NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Glossary of Terms Used in NERC Reliability Standards

Updated May 25, 2012

Introduction:

This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through May 25, 2012.

This reference is divided into two sections, and each section is organized in alphabetical order. The first section identifies all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the second section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards. (WECC, NPCC and Reliability*First* are the only Regions that have definitions approved by the NERC Board of Trustees. If other Regions develop definitions for approved Regional Standards using a NERC-approved standards development process, those definitions will be added to the Regional Definitions section of this glossary.)

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC approved" date added following a final Order approving the definition.

Immediately under each term is a link to the archive for the development of that term.

Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue. Definitions that have been remanded or retired are shaded in orange.

Any comments regarding this glossary should be reported to the following:
sarcomm@nerc.com with "Glossary Comment" in the subject line.

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Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Adequacy [Archive]		2/8/2005	3/16/2007	The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact [Archive]		2/7/2006	3/16/2007	The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Adverse Reliability Impact [Archive]		8/4/2011		The impact of an event that results in Bulk Electric System instability or Cascading.
After the Fact [Archive]	ATF	10/29/2008	12/17/2009	A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement [Archive]		2/8/2005	3/16/2007	A contract or arrangement, either written or verbal and sometimes enforceable by law.
Altitude Correction Factor [Archive]		2/7/2006	3/16/2007	A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Ancillary Service [Archive]		2/8/2005	3/16/2007	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter [Archive]		2/8/2005	3/16/2007	An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error [Archive]	ACE	2/8/2005	3/16/2007	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Area Interchange Methodology [Archive]		08/22/2008	11/24/2009	The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has received the Interchange information (initial or revised).
Automatic Generation Control [Archive]	AGC	2/8/2005	3/16/2007	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Available Flowgate Capability [Archive]	AFC	08/22/2008	11/24/2009	A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability [Archive]	ATC	2/8/2005	3/16/2007	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Available Transfer Capability [Archive]	ATC	08/22/2008	11/24/2009	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.
Available Transfer Capability Implementation Document [Archive]	ATCID	08/22/2008	11/24/2009	A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
ATC Path [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].

[1] See 18 CFR 37.6(b)(1)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Authority [Archive]	BA	2/8/2005	3/16/2007	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Base Load [Archive]		2/8/2005	3/16/2007	The minimum amount of electric power delivered or required over a given period at a constant rate.
Blackstart Capability Plan [Archive]		2/8/2005 Approved Retirement when EOP-005-2 becomes effective 8/5/2009	3/16/2007	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Blackstart Resource [Archive]		8/5/2009		A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan
Block Dispatch [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).
Bulk Electric System [Archive]	BES	2/8/2005	3/16/2007	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Burden [Archive]		2/8/2005	3/16/2007	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices [Archive]		8/22/2008	Not approved; Modification directed 11/24/09	Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Bus-tie Breaker [Archive]		8/4/2011		A circuit breaker that is positioned to connect two individual substation bus configurations.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Capacity Benefit Margin [Archive]	CBM	2/8/2005	3/16/2007	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document [Archive]	CBMID	11/13/2008	11/24/2009	A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency [Archive]		2/8/2005	3/16/2007	A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading [Archive]		2/8/2005	3/16/2007	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cascading Outages [Archive]		11/1/2006 Withdrawn 2/12/2008	FERC Remanded 12/27/2007	~~The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.~~
Clock Hour [Archive]		2/8/2005	3/16/2007	The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration [Archive]		2/8/2005	3/16/2007	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor [Archive]		2/8/2005	3/16/2007	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Confirmed Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has verified the Arranged Interchange.
Congestion Management Report [Archive]		2/8/2005	3/16/2007	A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss [Archive]		8/4/2011		All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Constrained Facility [Archive]		2/8/2005	3/16/2007	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency [Archive]		2/8/2005	3/16/2007	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve [Archive]		2/8/2005	3/16/2007	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path [Archive]		2/8/2005	3/16/2007	An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Control Performance Standard [Archive]	CPS	2/8/2005	3/16/2007	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan [Archive]		2/7/2006	3/16/2007	A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path [Archive]		5/2/2006	3/16/2007	A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets [Archive]		5/2/2006	1/18/2008	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Critical Cyber Assets [Archive]		5/2/2006	1/18/2008	Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment [Archive]		2/8/2005	3/16/2007	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold [Archive]		2/8/2005	3/16/2007	The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets [Archive]		5/2/2006	1/18/2008	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Security Incident [Archive]		5/2/2006	1/18/2008	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Delayed Fault Clearing [Archive]		11/1/2006	12/27/2007	Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand [Archive]		2/8/2005	3/16/2007	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management [Archive]	DSM	2/8/2005	3/16/2007	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Direct Control Load Management [Archive]	DCLM	2/8/2005	3/16/2007	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispatch Order [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.
Dispersed Load by Substations [Archive]		2/8/2005	3/16/2007	Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor [Archive]	DF	2/8/2005	3/16/2007	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Distribution Provider [Archive]	DP	2/8/2005	3/16/2007	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Disturbance [Archive]		2/8/2005	3/16/2007	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard [Archive]	DCS	2/8/2005	3/16/2007	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Disturbance Monitoring Equipment [Archive]	DME	8/2/2006	3/16/2007	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders[2]: • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions
Dynamic Interchange Schedule or Dynamic Schedule [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Dynamic Transfer [Archive]		2/8/2005	3/16/2007	The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

[2] Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Economic Dispatch [Archive]		2/8/2005	3/16/2007	The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy [Archive]		2/8/2005	3/16/2007	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter [Archive]	ESP	5/2/2006	1/18/2008	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Element [Archive]		2/8/2005	3/16/2007	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Emergency or BES Emergency [Archive]		2/8/2005	3/16/2007	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange [Archive]	Emergency RFI	10/29/2008	12/17/2009	Request for Interchange to be initiated for Emergency or Energy Emergency conditions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Energy Emergency [Archive]		2/8/2005	3/16/2007	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating [Archive]		2/7/2006	3/16/2007	The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
Existing Transmission Commitments [Archive]	ETC	08/22/2008	11/24/2009	Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Facility [Archive]		2/7/2006	3/16/2007	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating [Archive]		2/8/2005	3/16/2007	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault [Archive]		2/8/2005	3/16/2007	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk [Archive]		2/7/2006	3/16/2007	The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand [Archive]		2/8/2005	3/16/2007	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service [Archive]		2/8/2005	3/16/2007	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover [Archive]		2/7/2006	3/16/2007	An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate [Archive]		2/8/2005	3/16/2007	A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Flowgate [Archive]		08/22/2008	11/24/2009	1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
Flowgate Methodology [Archive]		08/22/2008	11/24/2009	The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage [Archive]		2/8/2005	3/16/2007	1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias [Archive]		2/8/2005	3/16/2007	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Bias Setting [Archive]		2/8/2005	3/16/2007	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Deviation [Archive]		2/8/2005	3/16/2007	A change in Interconnection frequency.
Frequency Error [Archive]		2/8/2005	3/16/2007	The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation [Archive]		2/8/2005	3/16/2007	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response [Archive]		2/8/2005	3/16/2007	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Generator Operator [Archive]	GOP	2/8/2005	3/16/2007	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner [Archive]	GO	2/8/2005	3/16/2007	Entity that owns and maintains generating units.
Generator Shift Factor [Archive]	GSF	2/8/2005	3/16/2007	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor [Archive]	GLDF	2/8/2005	3/16/2007	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Generation Capability Import Requirement [Archive]	GCIR	11/13/2008	11/24/2009	The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.
Host Balancing Authority [Archive]		2/8/2005	3/16/2007	1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value [Archive]		2/8/2005	3/16/2007	Data measured on a Clock Hour basis.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Implemented Interchange [Archive]		5/2/2006	3/16/2007	The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange [Archive]		2/8/2005	3/16/2007	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)
Independent Power Producer [Archive]	IPP	2/8/2005	3/16/2007	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc. [Archive]	IEEE	2/7/2006	3/16/2007	
Interchange [Archive]		5/2/2006	3/16/2007	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority [Archive]	IA	5/2/2006	3/16/2007	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Distribution Calculator [Archive]	IDC	2/8/2005	3/16/2007	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange Schedule [Archive]		2/8/2005	3/16/2007	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction [Archive]		2/8/2005	3/16/2007	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag [Archive]		2/8/2005	3/16/2007	The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service [Archive]		2/8/2005	3/16/2007	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection [Archive]		2/8/2005	3/16/2007	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection Reliability Operating Limit [Archive]	IROL	2/8/2005	3/16/2007 Retired 12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnection Reliability Operating Limit [Archive]	IROL	11/1/2006	12/27/2007	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.
Interconnection Reliability Operating Limit T_v [Archive]	IROL T_v	11/1/2006	12/27/2007	The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.
Intermediate Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities
Interruptible Load or Interruptible Demand [Archive]		11/1/2006	3/16/2007	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control [Archive]		2/8/2005	3/16/2007	Automatic Generation Control of jointly owned units by two or more Balancing Authorities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Limiting Element [Archive]		2/8/2005	3/16/2007	The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load [Archive]		2/8/2005	3/16/2007	An end-use device or customer that receives power from the electric system.
Load Shift Factor [Archive]	LSF	2/8/2005	3/16/2007	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity [Archive]	LSE	2/8/2005	3/16/2007	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon [Archive]		8/4/2011		Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.
Market Flow [Archive]		11/4/2010	4/21/2011	The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
Minimum Vegetation Clearance Distance [Archive]	MVCD	11/3/2011		The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Misoperation [Archive]		2/7/2006	3/16/2007	• Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. • Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). • Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Load [Archive]		2/8/2005	3/16/2007	The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon [Archive]		1/24/2011	11/17/2011	The transmission planning period that covers Year One through five.
Net Actual Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load [Archive]		2/8/2005	3/16/2007	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service [Archive]		2/8/2005	3/16/2007	Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Non-Consequential Load Loss [Archive]		8/4/2011		Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.
Non-Firm Transmission Service [Archive]		2/8/2005	3/16/2007	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve [Archive]		2/8/2005	3/16/2007	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing [Archive]		11/1/2006	12/27/2007	A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator [Archive]		5/2/2007	10/16/2008	Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power) [Archive]		5/2/2007	10/16/2008	The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Nuclear Plant Licensing Requirements [Archive]	NPLRs	5/2/2007	10/16/2008	Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Interface Requirements [Archive]	NPIRs	5/2/2007	10/16/2008	The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Off-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service [Archive]	OASIS	2/8/2005	3/16/2007	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff [Archive]	OATT	2/8/2005	3/16/2007	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Plan [Archive]		2/7/2006	3/16/2007	A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Procedure [Archive]		2/7/2006	3/16/2007	A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process [Archive]		2/7/2006	3/16/2007	A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve [Archive]		2/8/2005	3/16/2007	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve – Supplemental [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage [Archive]		2/7/2006	3/16/2007	The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis [Archive]		10/17/2008	3/17/2011	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Outage Transfer Distribution Factor [Archive]	OTDF	8/22/2008	11/24/2009	In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Overlap Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Participation Factors [Archive]		8/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand [Archive]		2/8/2005	3/16/2007	1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period [Archive]		2/7/2006	3/16/2007	The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Security Perimeter [Archive]	PSP	5/2/2006	1/18/2008	The physical, completely enclosed (“six-wall”) border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Planning Assessment [Archive]		8/4/2011		Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority [Archive]	PA	2/8/2005	3/16/2007	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Coordinator [Archive]	PC	8/22/2008	11/24/2009	See Planning Authority.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Point of Delivery [Archive]	POD	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt [Archive]	POR	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service [Archive]	PTP	2/8/2005	3/16/2007	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Postback [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.
Power Transfer Distribution Factor [Archive]	PTDF	08/22/2008	11/24/2009	In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pro Forma Tariff [Archive]		2/8/2005	3/16/2007	Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System [Archive]		2/7/2006	3/17/2007 Will be retired 4/1/2013	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Protection System[3] [Archive] [Implementation Plan]		11/19/2010	2/3/2012	Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.
Pseudo-Tie [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.

[3] This term becomes effective on April 1, 2013.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Purchasing-Selling Entity [Archive]	PSE	2/8/2005	3/16/2007	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Ramp Rate or Ramp [Archive]		2/8/2005	3/16/2007	(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions [Archive]		2/7/2006	3/16/2007	The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rating [Archive]		2/8/2005	3/16/2007	The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology [Archive]		08/22/2008	11/24/2009	The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reactive Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that supplies energy to the load.
Reallocation [Archive]		2/8/2005	3/16/2007	The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time [Archive]		2/7/2006	3/16/2007	Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment [Archive]		10/17/2008	3/17/2011	An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Receiving Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority importing the Interchange.
Regional Reliability Organization [Archive]	RRO	2/8/2005	3/16/2007	1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Regional Reliability Plan [Archive]		2/8/2005	3/16/2007	The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve [Archive]		2/8/2005	3/16/2007	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Service [Archive]		2/8/2005	3/16/2007	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment RFI [Archive]		10/29/2008	12/17/2009	Request to modify an Implemented Interchange Schedule for reliability purposes.
Reliability Coordinator [Archive]	RC	2/8/2005	3/16/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Coordinator Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System [Archive]	RCIS	2/8/2005	3/16/2007	The system that Reliability Coordinators use to post messages and share operating information in real time.
Remedial Action Scheme [Archive]	RAS	2/8/2005	3/16/2007	See "Special Protection System"
Reportable Disturbance [Archive]		2/8/2005	3/16/2007	Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Request for Interchange [Archive]	RFI	5/2/2006	3/16/2007	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reserve Sharing Group [Archive]	RSG	2/8/2005	3/16/2007	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Resource Planner [Archive]	RP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Response Rate [Archive]		2/8/2005	3/16/2007	The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way [Archive]	ROW	2/7/2006	3/16/2007	A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Right-of-Way [Archive]	ROW	11/3/2011		The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.
Right-of-Way [Archive]	ROW	5/9/12		The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Scenario [Archive]		2/7/2006	3/16/2007	Possible event.
Schedule [Archive]		2/8/2005	3/16/2007	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency [Archive]		2/8/2005	3/16/2007	60.0 Hertz, except during a time correction.
Scheduling Entity [Archive]		2/8/2005	3/16/2007	An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path [Archive]		2/8/2005	3/16/2007	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority exporting the Interchange.
Sink Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Special Protection System (Remedial Action Scheme) [Archive]	SPS	2/8/2005	3/16/2007	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve [Archive]		2/8/2005	3/16/2007	Unloaded generation that is synchronized and ready to serve additional demand.
Stability [Archive]		2/8/2005	3/16/2007	The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit [Archive]		2/8/2005	3/16/2007	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition [Archive]	SCADA	2/8/2005	3/16/2007	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Surge [Archive]		2/8/2005	3/16/2007	A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage [Archive]		2/7/2006	3/16/2007	The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System [Archive]		2/8/2005	3/16/2007	A combination of generation, transmission, and distribution components.
System Operating Limit [Archive]	SOL	2/8/2005	3/16/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator [Archive]		2/8/2005	3/16/2007	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Telemetering [Archive]		2/8/2005	3/16/2007	The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating [Archive]		2/8/2005	3/16/2007	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line [Archive]		2/8/2005	3/16/2007	A circuit connecting two Balancing Authority Areas.
Tie Line Bias [Archive]		2/8/2005	3/16/2007	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error [Archive]		2/8/2005	3/16/2007	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction [Archive]		2/8/2005	3/16/2007	An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
TLR Log [Archive]		2/8/2005	3/16/2007	Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Flowgate Capability [Archive]	TFC	08/22/2008	11/24/2009	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Transfer Capability [Archive]	TTC	2/8/2005	3/16/2007	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction [Archive]		2/8/2005	3/16/2007	See Interchange Transaction.
Transfer Capability [Archive]		2/8/2005	3/16/2007	The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g*enerally equal to the transfer capability from "Area B" to "Area A."

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transfer Distribution Factor [Archive]		2/8/2005	3/16/2007	See Distribution Factor.
Transmission [Archive]		2/8/2005	3/16/2007	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint [Archive]		2/8/2005	3/16/2007	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer [Archive]		2/8/2005	3/16/2007	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line [Archive]		2/7/2006	3/16/2007	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator [Archive]	TOP	2/8/2005	3/16/2007	The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Operator Area [Archive]		08/22/2008	11/24/2009	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner [Archive]	TO	2/8/2005	3/16/2007	The entity that owns and maintains transmission facilities.
Transmission Planner [Archive]	TP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
Transmission Reliability Margin [Archive]	TRM	2/8/2005	3/16/2007	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Reliability Margin Implementation Document [Archive]	TRMID	08/22/2008	11/24/2009	A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service [Archive]		2/8/2005	3/16/2007	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider [Archive]	TSP	2/8/2005	3/16/2007	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Vegetation [Archive]		2/7/2006	3/16/2007	All plant material, growing or not, living or dead.
Vegetation Inspection [Archive]		2/7/2006	3/16/2007	The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection [Archive]		11/3/2011		The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Vegetation Inspection [Archive]		5/9/12		The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Wide Area [Archive]		2/8/2005	3/16/2007	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.
Year One [Archive]		1/24/2011	11/17/2011	The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

Reliability*First* Regional Definitions

The following definitions were developed for use in Reliability*First* Regional Standards.

RFC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Resource Adequacy [Archive]		08/05/2009	03/17/2011	The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand [Archive]		08/05/2009	03/17/2011	Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period [Archive]		08/05/2009	03/17/2011	A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
Wind Generating Station [Archive]		11/03/2011		A collection of wind turbines electrically connected together and injecting energy into the grid at one point, sometimes known as a "Wind Farm."
Year One [Archive]		08/05/2009	03/17/2011	The planning year that begins with the upcoming annual Peak Period

NPCC Regional Definitions

The following definitions were developed for use in NPCC Regional Standards.

NPCC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time [Archive]		11/04/2010	10/20/2011	The time of the final current zero on the last phase to interrupt.
Generating Plant [Archive]		11/04/2010	10/20/2011	One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

WECC Regional Definitions

The following definitions were developed for use in WECC Regional Standards.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Area Control Error† [Archive]	ACE	3/12/2007	6/8/2007	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control‡ [Archive]	AGC	3/12/2007	6/8/2007	Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction [Archive]		3/26/2008	5/21/2009	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Average Generation‡ [Archive]		3/12/2007	6/8/2007	Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).
Business Day‡ [Archive]		3/12/2007	6/8/2007	Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.
Disturbance‡ [Archive]		3/12/2007	6/8/2007	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Extraordinary Contingency‡ [Archive]		3/12/2007	6/8/2007	Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: *means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).*
Frequency Bias‡ [Archive]		3/12/2007	6/8/2007	Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.
Generating Unit Capability‡ [Archive]		3/12/2007	6/8/2007	Means the MVA nameplate rating of a generator.
Non-spinning Reserve‡ [Archive]		3/12/2007	6/8/2007	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating‡		3/12/2007	6/8/2007	Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
[Archive]				is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.
Operating Reserve‡ [Archive]		3/12/2007	6/8/2007	Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit‡ [Archive]	OTC	3/12/2007	6/8/2007	Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.
Primary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Secondary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).
Spinning Reserve‡ [Archive]		3/12/2007	6/8/2007	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
WECC Table 2[†] [Archive]		3/12/2007	6/8/2007	Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.
Functionally Equivalent Protection System [Archive]	FEPS	10/29/2008	4/21/2011	A Protection System that provides performance as follows: • Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards. • Each Protection System may have different components and operating characteristics.
Functionally Equivalent RAS [Archive]	FERAS	10/29/2008	4/21/2011	A Remedial Action Scheme ("RAS") that provides the same performance as follows: • Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards. • Each RAS may have different components and operating characteristics.
Security-Based Misoperation [Archive]		10/29/2008	4/21/2011	A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.
Dependability-Based Misoperation [Archive]		10/29/2008	4/21/2011	Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Commercial Operation [Archive]		10/29/2008	4/21/2011	Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Qualified Transfer Path Curtailment Event [Archive]		2/10/2009	3/17/2011	Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.
Relief Requirement [Archive]		2/10/2009	3/17/2011	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Transfer Distribution Factor [Archive]	TDF	2/10/2009	3/17/2011	The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
Contributing Schedule [Archive]		2/10/2009	3/17/2011	A Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Qualified Transfer Path [Archive]		2/10/2009	3/17/2011	A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Qualified Controllable Device [Archive]		2/10/2009	3/17/2011	A controllable device installed in the Interconnection for controlling energy flow and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.

Endnotes

[†] FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.

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Glossary of Terms



Approved by the Reliability Standards Committee

October 26, 2011

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Actual Interchange		Metered electric **power** that flows from one entity to another.	D5
Applicable emergency limits		These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc. **Emergency** limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes. The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**. The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)	D1 D7
Area		An **Area** (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as **control areas** as defined by the North American Electric Reliability Council (NERC) (the definition can be found in this glossary).	D1 D7 D8 D12
Area Control Error	**ACE**	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. (Source: NERC Glossary of Terms)	D2 D5 D8

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Term	Acronym	Definition	Directories that use this term
Automatic Generation Control	**AGC**	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction. (Source: NERC Glossary of Terms)	D2 D5 D8
Basic Minimum Power System		Consists of one or more generating stations, transmission lines, and substations operating in the form of an island for the purpose of initiating the restoration process. The Reliability Coordinator and Transmission Operator shall each identify its area's basic minimum power system(s) within its system restoration plan.	D8
Bipolar		Operation of HVdc with two **poles** of opposite polarity with negligible ground current.	D1
Blackstart Capability		The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering **power** without assistance from the electric system.	D8
Bulk Power System	**BPS**	The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area.**	D1 D2 D3 D4 D7 D9 D10
Cable		An underground or underwater circuit.	D4 D5 D7 D8

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Term	Acronym	Definition	Directories that use this term
Capacity		The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of **generation**, transmission, or other electrical equipment.	D1 D2 D5 D8
Commutation Failure		A fault in a thyristor valve group where the current transfer from one valve to the next is interrupted.	D4
Component		Refers to components of equipment or protection systems rather than **elements** of a **power** system. See **Element**.	D1 D3 D7
Contingency		An event, usually involving the loss of one or more **elements**, which affects the power system at least momentarily.	D1 D2 D5 D7
Converter		An operative unit comprised of either a rectifier or inverter bridge connected to an ac system through transformers and switching devices with the associated control equipment.	D4
Converter Transformer		A **power** transformer which transfers the energy from the thyristor valves to the connected ac system and vice-versa.	D4
Critical Components		Equipment required for continued and proper operation of a **key facility** in the event of a total loss of grid supply. Critical components include but are not limited to the following: ▪ blackstart generating units; ▪ substation backup power supplies; ▪ control center and telecommunication center backup power supplies and computer systems;	D8

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Term	Acronym	Definition	Directories that use this term
		▪ control center and telecommunication center computer room HVAC; ▪ telecommunication facilities backup power supplies.	
Declared Capability (of a generator or generating facility)		The facility ratings submitted by the Generator Owner to the respective Transmission Operator as per NERC Standard FAC-009.	D10
Delayed Fault Clearing		Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay. (Source: NERC Glossary of Terms)	D1
Demand		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer. (Source: NERC Glossary of Terms)	D1 D5
Disturbance		Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.	D1 D2 D4 D5 D7
Disturbance Monitoring Equipment	**DME**	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders2 • Sequence of event recorders which record equipment response to the event; • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective	D4

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Term	Acronym	Definition	Directories that use this term
		relays; • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions (Source: NERC Glossary of Terms)	
Economic Dispatch		The allocation of demand to individual generating units on line to effect the most economical production of electricity. (Source: NERC Glossary of Terms)	D2
Element		Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. (Source: NERC Glossary of Terms)	D1 D2 D4 D5 D7 D9 D10
Emergency		Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system. NPCC Specific Definition: **Emergency** — An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.	D1 D2 D4 D5 D7
Emergency Regional Reserve Redispatch		The regional coordination of actions to enhance **reliability** among **Areas** in response to a **Regional Reserve Deficiency.**	D5

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Emergency Regional Reserve Dispatch Energy		Electrical energy that is received and delivered among **Areas** in response to a **Regional Reserve Deficiency** to enhance regional **reliability.**	D5
Emergency Transfer Capability		The amount of **power** transfer allowed between **Areas** or within an **Area** when ope**rating** to meet NPCC **emergency** criteria contingencies [as defined in Directory #1].	D2
Energize		To make a piece of equipment or circuit alive.	D4
Fault		An electrical **short circuit**.	D1 D4 D7
Firm Capacity		Capacity that is as firm as the seller's native **load** unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting **reserve** is carried by the seller.	D1
Firm Load		That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions. (Source: Firm Demand defined in NERC Glossary of Terms)	D1 D2
First Contingency Loss		The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element.**	D5
Forced Outage		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure. (Source: NERC Glossary of Terms)	D1
Generation (Electricity)		The process of producing electrical energy from other forms of energy;	D1

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Term	Acronym	Definition	Directories that use this term
		also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh). Gross Generation — The electrical output at the terminals of the generator, usually expressed in megawatts (MW). Net Generation — Gross generation minus station service or unit service **power** requirements, usually expressed in megawatts (MW).	D2 D4 (Appendix A) D5 D7 (Appendices) D12
Generation Facility		Generating units, which are modeled as a single entity by the Transmission Operator.	D8 D9 D10
Generation Rejection		The process of deliberately removing preselected **generation** from a **power** system, or initiating HVdc power runback, in response to a **contingency** or an abnormal condition in order to maintain the integrity of the system. Synonym: Generator Dropping.	D1 D7
Gross Real Power Capability (of a generator or generating facility)		The maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.	D9
Gross Reactive Power Capability (of a generator or generating facility)		The maximum lagging and leading reactive capability at the generator terminals and at a specified Gross Real Power output for a specific seasonal capability period.	D10
Grounded		Connected to earth or some extended conducting body that serves instead of the earth, whether the connection is intentional or accidental.	D4 D7
Harmonic		A sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency. Note: For example, a component, the frequency of which is twice the fundamental frequency, is called a second harmonic.	D4
HVdc Link		A high Voltage direct current connection between two **power** systems often	D4

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		used to interconnect two asynchronous **power** systems.	
Inadvertent Interchange		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (IA – IS) (Source: NERC Glossary of Terms)	D5
Interconnection		When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or **Control Areas**. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a **Control Area** or system.	D1 D2 D5 D8 D12
Interchange		Energy transfers that cross Balancing Authority boundaries. (Source: NERC Glossary of Terms)	D1 (Appendix B) D2 D5
Interchange Schedule		An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction. (Source: NERC Glossary of Terms)	D1 D5
Interface		The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.	D1 (Appendices)
Interruptible Load		Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (Source: NERC Glossary of Terms)	D1 (Appendix D) D5
Island		A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission	D1 D8

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Term	Acronym	Definition	Directories that use this term
		system **elements.**	D12
Key Facilities		Facilities required to establish a **basic minimum power system** following a system blackout. These facilities are essential to the restoration plan of the **Control Area** and include generating stations having blackstart units and other selected generating stations, transmission **elements** which are part of the **basic minimum power system,** control centers and telecommunication centers and telecommunication facilities which are necessary to support **protection** and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations.	D8
Load		An end-use device or customer that receives power from the electric system. (Source: NERC Glossary of Terms)	D1 D2 D3 D4 D5 D7 (Appendices) D8 D9 D10 D12
Load Relief		**Load** reduction accomplished by **voltage reduction** and/or **load shedding**.	D1
Load Shedding		The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.	D2 D3 D4 D12
Local area		An electrically confined or radial portion of the system. The geographic	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.	D4
Maintenance Outage		The removal of equipment from service **availability** to perform work on specific **elements** that can be deferred, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.	D1
Net Capacity		The maximum capacity (or effective **rating**), modified for ambient limitations, that a generating unit, **power** plant, or electric system can sustain over a specified period, less the capacity used to supply the **demand** of station service or auxiliary needs.	D1
Net Real Power Capability (of a generator or generating facility)		The Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.	D9
Net Reactive Power Capability (of a generator or generating facility)		The **Gross Reactive Power Capability** adjusted for any applicable losses and auxiliary loads incurred up to the point of interconnection and at a specified Gross Real Power output for a specific seasonal capability period.	D10
Normal Fault Clearing		Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system.**	D1

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Term	Acronym	Definition	Directories that use this term
Normal (Precontingency) Operating Procedures		Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.	D1 (Appendix F)
Normal Transfer Capability		The amount of **power** transfer allowed between **Areas** or within an **Area** when operating to meet NPCC normal criteria contingencies [as defined in Directory #1].	D1 D2
Operating Capability		The maximum load carrying ability of generating equipment or other electrical apparatus under specified conditions for a given time interval.	D9
Operating Limit		The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-**contingency** criteria as determined by equipment loading capability and acceptable voltage conditions; (b) **stability** criteria; (c) post-**contingency** loading and voltage criteria.	D1 (Appendix C) D2 D5
Operating Capacity		The **capacity** claimed for any generating source recognizing any temporary deratings, governor load limits, proven maximum loading rates, starting times and equipment limitations including transmission **operating limits**.	D5
Operating Procedures		A set of policies, practices, or system adjustments that may be automatically or manually implemented by the **system operator** within a specified time frame to maintain the operational integrity of the interconnected electric systems.	D1 D5 D7
Operating Reserve		The sum of **ten-minute** and **thirty-minute reserve**.	D1 D2
Phase Shifting Transformer		A transformer that advances or retards the phase angle relationship of one circuit with respect to another to control **power** flow. Synonyms: Phase angle regulator, phase shifter.	D1 D2 D4
Pilot Protection		A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.	D4
Planned Outage		Removing the equipment from service **availability** for inspection and/or general overhaul of one or more major equipment groups. This outage	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		usually is scheduled well in advance.	
Pole (HVdc term)		A rectifier and an inverter, with associated filter banks and control equipment, tied together by a transmission line or bus.	D1
Power		See definitions for Real Power and Reactive Power.	D8
Power Swing		A transient change in the **power** flows on a system, usually of an oscillatory nature.	D1 D4 (Appendix A)
Protected element		The power system **element** protected by the subject **protection system**. Examples: Line, bus, transformer, generator.	D4
Protection		The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.	D1 D2 D3 D4 D7
Protection group		A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups. Notes: (a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2. (b) Pilot protection is considered to be one protection group.	D1 D3 D4 D7
Protection System		Element Basis	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**. Terminal Basis One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.	D3 D4 D7
Protective relay		A **relay** that detects a power system **fault** or abnormal condition and initiates appropriate control system action.	D3 D4
Rating		The operational limits of an electric system, facility, or **element** under a set of specified conditions.	D1 D5
Reactive Power		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).	D1 D2 D10
Real Power		The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).	D1 D2

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Term	Acronym	Definition	Directories that use this term
			D9 D10
Reclosing		Autoreclosing — The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers. High-speed autoreclosing — The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle. Manual Reclosing — The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised. Supervision — A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**). Synchronism-check — refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	D1
Regional Reserve Deficiency		When two or more **Areas** are deficient in **ten minute reserve** after all **Area** coordinated actions have been deployed, including acquiring emergency energy and/or capacity but excluding the shedding of firm load.	D5
Relay		An electrical device designed to respond to input conditions in a prescribed	D1

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Term	Acronym	Definition	Directories that use this term
		manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).	D3 D4 D7 D12
Reliability		The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — Adequacy and **Security.** Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**. Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements.**	D1 D2 D5 D9 D10
Reportable Events		**System disturbances** involving losses of **load**, **generation** or transmission facilities within NPCC **Control Areas** which equal or exceed the following criteria are reportable events: (1) Actual net **interchange** deviations equal to or greater than 500 MW (Maritime: 300 MW). (2) Loss of **generation** or **load** equal to or greater than 500 MW (Maritime: 300 MW). (3) System frequency deviations equal to or greater than 0.03 Hz (Hydro-Quebec: 0.5 Hz). (System frequency deviations that occur for events outside of the NPCC are reported for analysis of frequency response, but are not included in the reporting for the NERC Disturbance Control Standard.)	D5

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Term	Acronym	Definition	Directories that use this term
Reserve		In normal usage, reserve is the amount of capacity available in excess of the demand	D1 D2 D5
Reserve on Automatic Generation Control (AGC)		That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load** without need for manual action.	D5
Reserve Requirement		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area supply adequacy.	D2 D5
Resource		Resource refers to the total contributions provided by supply-side and **demand**-side facilities and/or actions. Supply-side facilities include utility and non-utility **generation** and purchases from neighboring systems. **Demand**-side facilities include measures for reducing **load**, such as conservation, **demand** management, and **interruptible load.**	D1 D2 D5 D8 D9 D10
Scheduled Interchange		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time. (Source: Net Scheduled Interchange defined in NERC Glossary of Terms)	D5
Second Contingency Loss		The largest **capacity** outage which would result from the loss of a single **element** after allowing for the First Contingency Loss.	D5
Short Circuit		An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. *Note:* The term **fault** or short-circuit **fault** is used to describe a short circuit.	D4 D7
Short Time Emergency Rating	**STE**	The maximum loading of electrical equipment which can be sustained for 15 minutes based on nominal ambient conditions and recognizing preloading conditions.	D1 (Appendix C)

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Term	Acronym	Definition	Directories that use this term
Significant Adverse Impact		With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**: a. instability; • any instability that cannot be demonstrably contained to a well-defined **local area**. • any loss of synchronism of generators that cannot be demonstrably contained to a well-defined **local area** b. unacceptable system dynamic response; • an oscillatory response to a **contingency** that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event. c. unacceptable equipment tripping • tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a **protection system** in response to a stable **power swing** • operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required d. voltage levels in violation of applicable **emergency** limits; e. loadings on transmission facilities in violation of applicable **emergency** limits.	D1 (Appendix E) D5
Single Contingency		A single event, which may result in the loss of one or more **elements.**	D5
Special Protection System	**SPS**	**Special Protection System (SPS)** – A **protection system** designed to detect abnormal system conditions and take corrective action other than the	D1 D3

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Term	Acronym	Definition	Directories that use this term
		isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or **power** flows. However, the following are not considered **SPS's**: - Automatic underfrequency **load shedding;** - Automatic under voltage **load shedding**, and - Manual or automatic locally controlled shunt devices.	D4 (Appendix A) D7
Stability		The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: NERC Glossary of Tems)	D1 D4
Static Var Compensator	**SVC**	A combination of controlled shunt reactors and switched capacitor banks, used to affect the **reactive power** flow of the system or to regulate the system voltage.	D1 (Appendix G) D2 D4
Synchronize		The process of connecting two previously separated alternating current apparatuses or systems after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).	D8

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Term	Acronym	Definition	Directories that use this term
Synchronized Reserve		The unused portion of generating capacity which is synchronized to the system and ready to pick up **load** to claimed capacity and capacity which can be made available by curtailing pumping hydro units.	D5
Synchronous Condenser		A synchronous machine which operates without mechanical load to supply or absorb **reactive power** for voltage control purposes.	D2 D10
System Disturbance		An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.	D1 D2 D4 D5 D7
System Operator		An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time. (Source: NERC Glossary of Terms)	D2 D3 D8
Teleprotection		A form of **protection** that uses a communication channel.	D4 D7
Ten-Minute Reserve		The sum of **synchronized** and non-**synchronized reserve** that is fully available in ten minutes.	D1 D5
Thirty-Minute Reserve		The sum of **synchronized** and non-**synchronized reserve** that can be utilized in thirty minutes, excluding capacity assigned to **ten-minute reserve**.	D5
Tie Line		A circuit connecting two Balancing Authority Areas.	D1 D2 (Appendix B) D5
Tie Line Bias		A mode of operation under automatic **generation** control in which the **area control error** is determined by the actual net **interchange** minus the biased	D2

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Term	Acronym	Definition	Directories that use this term
		scheduled net **interchange.**	
Total Transfer Capability	**TTC**	The amount of electric **power** that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions: 1. For the existing or planned system configuration, and with **normal** (**precontingency**) **operating procedures** in effect, all facility loadings are within normal **ratings** and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric system **element**, such as a transmission line, transformer, or generating unit. 3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of any automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits 4. With reference to condition 1 above, in the case where precontingency facility loadings reach normal thermal **ratings** at a transfer level below that at which any first **contingency** transfer limits are reached, the transfer capability is defined as that transfer level at which such normal **ratings** are reached. 5. In some cases, individual system, **power pool,** subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of	D5

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Term	Acronym	Definition	Directories that use this term
		transfer capability limits. If the resulting transfer limits for these multiple **contingencies** are more restrictive than the single contingency considerations described above, the more restrictive **reliability** criteria or guides must be observed.	
Transfer Capability		The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A." (Source: NERC Glossary of Terms)	D1 D2 D5
Transient Stability		The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance** and to regain a state of equilibrium following that disturbance.	D1
Verified Capability (of a generator or generating facility)		The capability as demonstrated by the methods specified in NPCC Directories and accepted by the Transmission Operator.	D9 D10
Voltage Reduction		A means to reduce the **demand** by lowering the customer's voltage.	D1 D2 (Appendix B) D5 (Appendix 3)
Voltage Regulating Transformer		A transformer that increases or decreases the voltage magnitude relationship of one circuit with respect to another, most often used to control voltage but also to control **reactive power** flow.	D1
With Due Regard To Reclosing		This phrase means that before any manual system adjustments, recognition will be given to the type of **reclosing** (i.e., manual or automatic) and the kind of **protection.**	D1

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Term	Acronym	Definition	Documents that use this term
Automatic Operating Systems		**Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.	
Auto-reclosing		The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Auto-reclosing does not include automatic closing of capacitor or reactor circuit breakers.	
Available Transfer Capability	**ATC**	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the **Transmission Reliability Margin (TRM)**, less the sum of existing transmission commitments (which includes retail customer service) and the **Capacity Benefit Margin (CBM)**.	
Availability		A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.	
Average Demand		The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.	
Base load Capacity		Capacity used to serve an essentially constant level of customer **demand**. Base load generating units typically operate whenever they are available.	
Billing Demand		The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.	
Bottled Energy/Power/Capacity		Energy/Power/Capacity which is available at the source but which cannot be delivered to the point of use because of restrictions in the transmission	

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Term	Acronym	Definition	Documents that use this term
		system. Also referred to as Locked-In Energy/Power/Capacity.	
Capacity Benefit Margin	**CBM**	CBM is defined as that amount of transmission transfer capability reserved by **load** serving entities to ensure access to **generation** from interconnected systems to meet **generation reliability** requirements.	
Coincident Demand		The sum of two or more demands that occur in the same demand interval.	
Contingency Reserve Adjustment Factor		A factor used in determining the additional **ten-minute reserve** that each **Area**, not meeting the DCS requirement for a given quarter, must carry. It is calculated using the following formula: $CRA_{quarter} = 2 -$ {the average percentage DCS (expressed as a decimal) for the quarter of measurement}	
Continuous Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand indefinitely without loss of equipment life. (Normally not used in NPCC)	
Contract Demand		The amount of **capacity** that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.	
Control Area		An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling **generation** to maintain its net **interchange schedule** with other Control Areas and contributing to frequency regulation of the **Interconnection.**	
Demand Interval		The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.	

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Term	Acronym	Definition	Documents that use this term
Double Element Contingency		A **contingency** involving the loss of two **elements**.	
Emergency Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or **element** can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.	
Firm Demand		That portion of the Contract Demand that a **power** supplier is obligated to provide except when system **reliability** is threatened or during **emergency** conditions.	
First Contingency Incremental Transfer Capability	**FCITC**	The amount of **power**, incremental above normal base **power** transfers, that can be transferred over the transmission network in a reliable manner based on the following conditions: 1. For the existing or planned system configuration, and with normal (pre-**contingency) operating procedures** in effect, all facility loadings are within normal **ratings** and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric **element**, such as a transmission line, transformer, or generating unit. 3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency**	

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Term	Acronym	Definition	Documents that use this term
		ratings and all voltages are within **emergency** limits.	
First Contingency Total Transfer Capability	**FCTTC**	The algebraic sums of the FCITC values and the appropriate total interregional transfers assumed in the base load flow model used for the FCITC calculations.	
Forced Outage Rate		The hours a generating unit, transmission line, or other facility is forced out of service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.	
Harmonic Current		A periodic component of current having a frequency that is an integral multiple of that currents fundamental frequency. Harmonic currents are normally measured in amperes or in percent of the fundamental frequency current, generally at specific frequencies, such as second and third harmonics. Harmonic currents can, for example, be generated by HVdc converters, **Static Var Compensators** (SVC) and geomagnetically induced currents (GIC).	
High Speed Fault Clearing		Fault clearing consistent with correct operation of high-speed relays and the associated circuit breakers without intentional time delay. *Notes:* The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.	
High-Speed Auto reclosing		The auto reclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of auto reclosing is generally not supervised by voltage magnitude or phase angle.	
Integrated Demand		The average of the instantaneous demands over the demand interval.	

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Term	Acronym	Definition	Documents that use this term
Interchange Scheduling		The actions taken by scheduling entities to arrange transfer of electric **power**. The schedule consists of an agreement on the amount, start and end times, ramp rate, and degree of firmness.	
Instantaneous Demand		The rate of energy delivered at a given instant.	
Limiting Contingency		The **contingency** which establishes the **transfer capability**.	
Load Cycle		The normal pattern of **demand** over a specified time period associated with a device or circuit.	
Long Time Emergency (LTE) Rating		The maximum rating of electrical equipment based on nominal ambient conditions and recognizing the nominal **load cycle** for a long period such as 24 hours.	
Manual Reclosing		The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.	
Negative Shared Activation Reserve Energy		Energy received by an assisting **Area** from a contingent **Area** for an eligible **resource** loss having a concurrent effective loss of demand that exceeds the loss of energy from the **resource** loss, and is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Non coincident Demand		The sum of two or more demands that occur in different demand intervals.	
Non recallable Available Transfer Capability	**NATC**	Total Transmission Capability less the **Transmission Reliability Margin**, less non recallable reserved transmission service (including the **Capacity Benefit Margin**).	
Non-Synchronized Reserve		That portion of **operating capacity**, which is available for synchronizing to	

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Term	Acronym	Definition	Documents that use this term
		the network and that capacity which can be made available by applying load management techniques such as curtailing **interruptible loads** or implementing **voltage reductions**.	
Normal Incremental Transfer Capability	**NITC**	The amount of electric **power**, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-**contingency** loadings reach the normal thermal **rating** of a facility prior to any first **contingency** transfer limits being reached. When this occurs, NITC replaces FCITC as the most limiting transfer capability.	
Normal Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand through the daily **demand** cycles without loss of equipment life.	
NPCC Emergency Criteria Contingencies		The set of contingencies to be observed when operating the **bulk power system** under **emergency** conditions.	
NPCC Normal Criteria Contingencies		The set of contingencies to be observed when operating the **bulk power system** under normal conditions.	
Peak Demand		The highest electric **power** requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.	
Peaking Capacity		Capacity used to serve **peak demand**. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.	
Permanent Fault		A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.	

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Term	Acronym	Definition	Documents that use this term
Pole (of an ac switching device)		That portion of the device associated exclusively with one electrically separated conducting path of the main circuit of the device.	
Post contingency Operating Procedures		Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.	
Power		Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilo volt amperes (kVA) or megavoltamperes (MVA).	
Power Pool		Two or more interconnected electric systems operated and/or planned to supply **power** for their combined **demand** requirements.	
Recallable Available Transmission Capability	**RATC**	Total Transmission Capability less the **Transmission Reliability Margin**, less recallable transmission service, less non-recallable transmission service (including the **Capacity Benefit Margin**).	
Reclosing *This term by itself is not defined in the NPCC glossary.*		*Need to develop this definition.*	
Regional Reserve Sharing		Procedure that allows participating **Areas** to reduce the requirement for **reserve** within its **Area** due to the availability and deliverability of **reserve** from other **Areas.**	
Regional Reserve Sharing Energy		Energy delivered to a contingent **Area** from assisting **Areas** that is converted from delivered **Shared Activation Reserve Energy** after the **Shared Activation Reserve Energy** has been delivered for 30 minutes; maintained until the Contingent **Area** requests a return to normal but not longer than sixty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Shared Activation Reserve Energy		Energy delivered from an assisting **Area** to a contingent **Area** that is implemented at a zero time ramp rate immediately following allocation	

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Term	Acronym	Definition	Documents that use this term
		notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Single Element Contingency		A **contingency** involving the loss of one **element**.	
Small-Signal Stability		The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.	
Stability Limit		See NERC definition.	
Supervision		A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).	
Supervisory Control		A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.	
Surge		See NERC definition.	
Synchronism-check		Refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	
Synchronism-check Relay		A verification **relay** whose function is to operate when two input voltages satisfy predetermined operating parameters.	
Transient Fault		A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.	

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Term	Acronym	Definition	Documents that use this term
Transmission Reliability Margin	**TRM**	TRM is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.	
Wheeling		The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.	

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Term	Regional Standard	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time **(Archive)**	PRC-002-NPCC-01	DM	11/04/2010	10/20/2011	The time of the final current zero on the last phase to interrupt. (Source: NERC Glossary of Terms)
Generating Plant **(Archive)**	PRC-002-NPCC-01	DM	11/04/2010	10/20/2011	One or more generators at a single physical location whereby any single contingency can affect all the generators at that location. (Source: NERC Glossary of Terms)

NPCC, Inc.

1040 Avenue of the Americas - 10th Floor
New York, New York 10018-3703

NPCC Regional Standards Committee
Preliminary Agenda--Draft
Meeting # 12-3

May 2, 2012 10:00 a.m. - 5:00 p.m.
May 3, 2012 8:00 a.m. - 3:00 p.m.

Niagara Power Project
New York Power Authority
5777 Lewiston Road
Lewiston, New York 14092

Dress Business Casual

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Call in 719-785-1707, Guest Code 8287#

Note: Glossary of Terms Used in NERC Reliability Standards dated February 8, 2012, and the NPCC Glossary of Terms dated October 26, 2011 included in the Meeting Materials.

Items in red from the May 2, 2012 session.
Items in green from the May 3, 2012 session.

Guy Zito called the meeting to order at 10:00 a.m.
Guy Zito called the meeting to order at 8:32 a.m.

Attendees introduced themselves.

	Name	***Organization***	***Sector***
1.	Guy Zito	Northeast Power Coordinating Council	
2.	Lee Pedowicz	Northeast Power Coordinating Council	
3.	Bruce Metruck	New York Power Authority	6
4.	Ben Wu	Orange and Rockland Utilities	1
5.	Don Weaver	New Brunswick System Operator	2
6.	David Kiguel	Hydro One Networks Inc.	1
7.	Michael Lombardi	Northeast Utilities	1
8.	Greg Campoli	New York Independent System Operator	2
9.	Gerry Dunbar	Northeast Power Coordinating Council	
10.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	1
11.	Mack Argentieri	New York Power Authority (guest)	
12.	Brian Robinson	Utility Services	5
13.	Si Truc Phan	Hydro-Quebec TransEnergie	2
14.	Joel Charlebois	AESI (guest)	
15.	Diane Barney	State of New York Public Service Commission Department of Public Service	6
16.	Howard Gugel	NERC (guest)	

On the Phone

	Name	***Organization***	***Sector***
1.	Wayne Sipperly	New York Power Authority	4
2.	Mike Garton	Dominion Resources Services, Inc.	4
3.	Kal Ayoub (guest)	FERC	5/2/12 only
4.	Michael Jones	National Grid	3
5.	Helen Lainis (for Tina Teng)	IESO	5/2/12 only
6.	John Pearson	ISO - New England	5/2/12 only--for Item 7eComment (ALR) discussion
7.	John Lim	Consolidated Edison Co. of New York, Inc.	5/3/12 only--for Item 7a Comment discussion
8.	Nicholas Occhionero (guest)	State of New York Public Service Commission	5/3/12

		Department of Public Service	

Mack Argentieri (NYPA) identified the emergency exits and procedures for the meeting facility. Guy Zito thanked Mr. Argentieri for leading the tour of the power plant yesterday. The tour was exceptional in its thoroughness and information presented.

Lee Pedowicz read the NPCC Antitrust Guidelines.

Guy Zito reminded the attendees that the Meeting, its materials, and discussions are open and available to the public.

1. **Antitrust Guidelines, Agenda, Introductions, Roster**
   a. Nominations for RSC co-Vice Chairs, RSC Executive Committee at large members.
   b. Silvia Parada Mitchell from NextEra replacing Chantel Haswell. For National Grid Michael Jones will be replacing Saurabh Saksena.

Item 1a--Guy Zito asked Greg Campoli, Michael Lombardi and Mike Garton to leave the meeting for the discussions on their nominations for the positions of Vice-chair, and Executive Committee. Discussion ensued on the candidates. A motion was made by Guy Zito to approve Michael Lombardi for the Vice-chair position. David Kiguel nominated Michael Lombardi, and Chris de Graffenried seconded. A vote was taken, and Michael Lombardi was approved to be a Vice-chair.

Guy Zito remarked that there are opportunities for the RSC Vice-chair to encourage participation. Additional responsibilities will be written into the RSC Scope for the position.

Bruce Metruck nominated Greg Campoli for the second Vice-chair opening. It was seconded by David Kiguel. A vote was taken, and Greg Campoli was approved to be a Vice-chair.

David Kiguel indicated that he wanted to be considered for the position of Canadian Representative on the Executive Committee. Diane Barney nominated both David Kiguel and Mike Garton for the position, seconded by Don Weaver. Both were approved.

Item 1b--From the May 1, 2012 NPCC Board of Directors teleconference meeting, Guy Zito reported that Michael Jones was appointed to the RSC replacing Saurabh Saksena. Silvia Parada Mitchell was also appointed replacing Chantel Haswell.

2. **RSC March, 2012 Meeting Minutes** (in Meeting Materials Package)
   a. March, 2012 Meeting minutes for approval. Scott Nied's Joint RSC/CC Meeting Minutes for information.

Guy Zito opened discussion of the March, 2012 RSC Meeting Minutes. Michael Lombardi made a motion to approve as read. Greg Campoli seconded the motion. With one abstention, all the members voted to approve the Minutes as written.

3. Action Item List (expanded table in Appendix B, supporting materials in Meeting Materials Package)

Action Item Number	Description	Owner	Due	Status
63	Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Outgrowth of RSC/CC joint session April 21, 2010. Joint RSC/CC Meeting this meeting.

Greg Campoli reported that Gerry Dunbar coordinate with TFSP on Directories 4 and 7. There will be a face to face meeting May 8, 2012. David Kiguel will attend. Regarding Directories 4 and 7, Guy Zito commented that their contents are difficult to write into requirements that are auditable. There was a suggestion to write requirements that would be more readily auditable. David Kiguel commented that the contents of the existing requirements are valuable, and every effort should be made to retain that information. The May 8, 2012 Meeting will not include the entire TFSP, just select members.

a. NPCC Members on NERC Drafting Teams. Need caretaker for the document.

The NPCC Members on NERC Drafting Teams needs a new "owner". Michael Jones volunteered to take it over. Greg Campoli made a suggestion that the company affiliations of the Drafting Team members be listed, and that the list needs to be "cleaned up" for the next (July) RSC Meeting. Mike Jones will update the list, and will circulate to the RSC for its comments before the July RSC Meeting.

4. Items Requiring RSC Approval

There were no items requiring RSC approval.

5. Executive Tracking Summary (in Meeting Materials Package)

a. Review entries.

Michael Lombardi lead the discussion. Guy Zito reported that NERC's Andy Dressel gave him assurances that PRC-006-NPCC-01 will be filed with FERC by May 7, 2012.

Howard Gugel reported on the CIP ballot results that were posted May 1, 2012. Guy Zito suggested that line items be added for data requests, etc. Michael Lombardi will revise appropriately.

6. FERC

NOPRs					
Item	**NOPR**	**Docket No.**	**Posted**	**End Date**	**When Effective**
6N-1	Transmission Planning Reliability Standards--FERC Proposes to Remand TPL-001-2	RM12-1-000	4/19/12		

Petitions			
Item	**Docket No.**	**Posted**	**Title**
6P-1	RM06-16-000	3/16/12	Petition of the North American Electric Reliability Corporation For Approval of Proposed Reliability Standards, *North American Electric Reliability Corporation*, FERC Docket No. RM06-16-000--Correction of Cascading outages errata.
6P-2	RM12-4-000	4/24/12	Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard FAC-003-2—Transmission Vegetation Management, *North American Electric Reliability Corporation*, FERC Docket No. RM12-4-000--Errata filing.
6P-3	RD12-1-000	4/27/12	Errata to Petition of NERC for Approval of Proposed Texas Reliability Entity Regional Reliability Standard IRO-006-TRE-1 — IROL and SOL Mitigation in the ERCOT Interconnection, *North American Electric Reliability Corporation*, FERC Docket No. RD12-1-000

Final Rule			
Item	**Docket No.**	**Posted**	**Summary**
6F-1	RM11-16-000 - Order No. 759	3/15/12	FERC approved PRC-023-2 (Transmission Relay Loadability) submitted by NERC. PRC-023-2 requires transmission owners, generation owners, and distribution providers to set load-responsive phase protective relays according to specific criteria to ensure that the relays reliably detect, and protect the electric network from fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability.
6F-2	RM11-18-000	4/19/12	FERC remands proposed TPL-002-0b, submitted by NERC. The proposed TPL-002-b includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process. FERC finds that this provision is vague, unenforceable, and not responsive to previous Commission directives on this matter. NERC to utilize its Expedited Reliability Standards Development Process to develop timely modifications to TPL-002-0b, Table 1 footnote 'b' in response to the remand..

6F-3	RM11-11-000 - Order No. 761	4/19/12	FERC approves modified CIP Standards, CIP-002-4 through CIP-009-4. The Version 4 CIP Reliability Standards include "bright line" criteria for the identification of Critical Assets, which replace the risk-based assessment methodology developed and applied by applicable entities under the Version 3 CIP Reliability Standards. Version 4 includes other conforming modifications to the remaining CIP Reliability Standards, CIP-003-4 through CIP-009-4. FERC approves NERC's filing, as amended by its errata filing, with regard to the related VRFs, the VSLs with modifications, the implementation plan, and effective date proposed by NERC. FERC also approves the concurrent retirement of the currently effective Version 3 CIP Reliability Standards, CIP-002-3 to CIP-009-3.

Other			
Item	**Docket No.**	**Posted**	**Summary**
6O-1	RC11-6-000, RC12-1-000, RC12-2-000, RC12-6-000, RC12-7-000, RC12-8-000	3/15/12	Order Accepting With Conditions the Electric Reliability Organization's Petition Requesting Approval Of New Enforcement Mechanisms And Requiring Compliance Filing. FERC accepted with limited conditions NERC's proposal to make informational filings in a "Find, Fix, Track and Report" (FFT) spreadsheet

			format of lesser-risk, remediated possible violations of Reliability Standards.
6O-2	RM10-6-000	3/15/12	Informational Filing Of The North American Electric Reliability Corporation In Response To Order No. 754. Submitted for informational purposes in compliance with Paragraph 20 of Order No. 754, a report on the reliability issues concerning system protection associated with the Commission-approved interpretation of Requirement R1.3.10 of Reliability Standard TPL-002-0.
6O-3	RM96-1-037	3/23/12	Comments Of The North American Electric Reliability Corporation In Response To Notice Of Proposed Rulemaking On Standards For Business Practices For Interstate Natural Gas Pipelines. NERC urges FERC to clarify in its final order that pipelines must notify both Balancing Authorities *and* Reliability Coordinators of operational flow orders and other critical notices.
6O-4	RR12-	3/30/12	NERC Standards Report, Status and Timetable for Addressing Regulatory Directives.
6O-5	AD12-12-000	3/30/12	Comments Of The North American Electric Reliability Corporation on the Coordination Between Natural Gas and Electricity Markets.
6O-6	RM06-16-010	3/30/12	Motion For An Extension Of Time Of The North American Electric Reliability Corporation. Additional time is needed to properly implement FERC directives in Order No. 693 with respect to BAL-003.
6O-7	RC-11-5-000	4/19/12	Order Denying Appeal of Electric Reliability Organization

			Compliance Registry Determination. In this order, FERC denied the appeal of the City of Holland, Michigan Board of Public Works of a registry decision by NERC. FERC agreed with NERC that Holland is properly included in the NERC Compliance Registry as a transmission owner (TO) and transmission operator (TOP), based on findings that Holland is not entitled to an exemption from the definition of bulk electric system as a radial facility, and that Holland has not otherwise demonstrated that its system is not material to the reliability of the interconnected transmission system.
6O-8	IC12-11-000 (for information)	4/23/12	FERC is soliciting public comment on the currently approved information collection, FERC–725, Certification of ERO; Procedures for Electric Reliability Standards. Comments on the collection of information are due June 22, 2012.
6O-9	RM12-4-000	4/23/12	FERC is posting and inviting comment upon a report prepared by the Pacific Northwest National Laboratory on the "Applicability of the 'Gallet Equation' to the Vegetation Clearances of NERC Reliability Standard FAC-003-2". Comments due May 23, 2012.
6O-10	RR06-1-015	4/30/12	NERC's submission of its Analysis of NERC Standards Process Results for the Fourth Quarter 2011 ("Ballot Results Filing"). This filing is submitted in response to the FERC January

			18, 2007 Order[1] requiring NERC to closely monitor and report to FERC the voting results for NERC Reliability Standards each quarter for an initial three year period, later extended an additional three years. The Ballot Results Filing addresses ballot results during the January 1, 2012 to March 31, 2012 time frame and includes NERC's analysis of the voting results, including trends and patterns of stakeholder approval of NERC Reliability Standards.
6O-11	AD12-13-000	4/30/12	Statement of FERC Commissioner Philip D. Moeller on Solar Disturbances to Earth's Geomagnetic Field.

Item 6N-1--Guy Zito commented that loss of load is the issue. The Notice is states that FERC might remand back to NERC.
Item 6P-1--Guy Zito reported that it was issued for clarification.

Item 6P-2--Guy Zito reported that errata correction was made and filed.

Item 6P-3--Guy Zito reported on the errata.

Item 6F-1--Guy Zito described the content of the posting.

Item 6F-2--Guy Zito reported that FERC is not happy with the proposed load shedding provision. Diane Barney raised the question that maybe NERC is seeking a rehearing? Gerry Dunbar asked about how to have a rehearing. Diane Barney commented that FERC has the option of accepting or denying a request for a rehearing.

Guy Zito reported that there are plans for the CEAP to be brought to high level FERC management for discussion and review. David Kiguel reported that the CEAP was well received at the NERC SC.

Item 6F-3--Guy Zito reported that April, 2014 will be the mandatory enforcement date. David Kiguel commented that even with the April 1, 2014 "auditable" date, some activities to move into compliance will have to start earlier. The CIP Standards are on the agenda for the Compliance Workshop to be held later this month. David Kiguel commented that there is concern over how long Version 4 will be in effect before Version 5 takes effect, because items might have to be completed in Version 4 that will be unnecessary to satisfy Version 5. Guy Zito asked how Version 5 builds on Version 4. Anything in Version 4 not needed in Version 5? Michael Lombardi commented that

there is industry confusion over the dates--effective, enforcement, etc. Guy Zito remarked that entities just want to know what they have to do, and when they have to do it.

Item 6O-1--Guy Zito remarked that particular attention has to be paid to Paragraph 81 because it may have a significant impact. Guy Zito will be attending a NERC Meeting the third week in May that will be going over the Order. Compliance persons will also be attending. Guy Zito requested that any thoughts regarding the Order be sent to him prior to the Meeting. Michael Lombardi brought up and lead a discussion on the mitigation and remediation issue in Paragraph 14. FERC is aware that Paragraph 81 could reduce the number of standards.

Item 6O-2--Guy Zito reported that data request will be an integral part of the Standard.

Item 6O-3--This item for information.

Item 6O-4--Guy Zito commented that the numbers of Directives are decreasing.

Item 6O-5--This item for information.

Item 6O-6--Ongoing effort, more time needed.

Item 6O-7--Guy Zito remarked that this could have an impact on the BES definition. It gives an indication of how FERC views radial lines, etc. May give an indication of how local networks will be treated.

Item 6O-8--Guy Zito reported that no action is required.

Item 6O-9--Chris de Graffenried reported that the Gallet equation is applicable to line design clearances.

Item 6O-10--This item for information.

Item 6O-11--This item for information.

a. FERC Meeting Summaries.
    1. March, 2012.
    2. April 19, 2012 Open Meeting Agenda, Meeting Summaries.

Item 6a.1--For information.

Item 6a.2--For information.

7. <u>Posted Projects</u> (in Meeting Materials Package)
Concluded Ballots--See Appendix C
Comment Forms Submitted--See Appendix D

a. Voting position codification.

b. Project 2007-12 Frequency Response Technical Conferences--May 22 and 24, 2012.

Item 7a--Guy Zito lead the discussion. If there is a division within the RSC, information is to be given to Ed Schwerdt to make a decision in his capacity as President and CEO. It will be included in RSC documentation.

Item 7b--Both conferences listed will cover the same information. Howard Gugel mentioned that there is information on the Meetings on the NERC Website.

	Project and Supporting Materials	**Current and Pending Ballots**		**Join Ballot Pools**		**Posted for Comment**	
a.	Project 2008-06 - Cyber Security Order 706 Version 5 CIP CIP-002-5 - Redline CIP-003-5 - Redline CIP-004-5 - Redline CIP-005-5 - Redline CIP-006-5 - Redline CIP-007-5 - Redline CIP-008-5 - Redline CIP-009-5 - Redline CIP-010-1 - Redline CIP-011-1 - Redline Implementation Plan - Redline Definitions - Redline Mapping Document - Redline CIP-002-4 CIP-003-4 CIP-004-4 CIP-005-4a CIP-006-4c CIP-007-4 CIP-008-4 CIP-009-4 Consideration of Comments from June 2010 Informal Comment Period Draft Consideration of Issues and Directives - Redline Announcement	Successive Ballots 5/11/12	5/21/12			Comment Forms (click title below for Word version) Comment Form A Comment Form B Comment Form C Comment Form D 4/12/12	5/21/12

	Project and Supporting Materials	Current and Pending Ballots		Join Ballot Pools		Posted for Comment	
	CIP Standard Version 5 8-24-11 Webinar Slides CIP Standard Version 5 4-10-12 Webinar Slides						
b.	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-003-X Redline to Last Posted Redline to Last Approved Implementation Plan Redline to Last Posted FAC-003-3 Redline to Last Posted Redline to Last Approved Implementation Plan Redline to Last Posted Consideration of Comment Report (FAC-003-3, FAC-003-X) PRC-005-1.1b Redline to Last Posted Implementation Plan Redline to Last Posted Consideration of Comment Report (PRC-005-1.1b) Technical Justification Document Redline Announcement	Recirculation Ballot 4/24/12	5/3/12				
c.	Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for					4/24/12	5/4/12

	Project and Supporting Materials	Current and Pending Ballots		Join Ballot Pools		Posted for Comment	
	SPCS Informal comments to be sent to scott.barfield@nerc.net, hohlbaughdg@firstenergycorp.com						
d.	Project 2009-01 - Disturbance and Sabotage Reporting EOP-004-2 Redline to Last Posted Implementation Plan Mapping Document Consideration of Issues and Directions VRF/VSL Justification Proposed NERC RoP Section 812 CIP-001-2a CIP-008-3 EOP-004-1 Announcement	Successive Ballot and Non-binding Poll 5/15/12	5/24/12			Submit Comments (Word version--ctrl+click here) 4/25/12	5/24/12
e.	Adequate Level of Reliability Revised Definition and Associated Documents Definition: Adequate Level of Reliability for the Bulk Electric System Technical Report Supporting Definition of Adequate Level of Reliability Discussion Paper - Risk Tolerance for Widespread BES Outages Mapping of Adequate Level of					Submit Comments (Word version--ctrl+click here) 4/25/12	6/25/12

	Project and Supporting Materials	Current and Pending Ballots		Join Ballot Pools		Posted for Comment	
	Reliability for BES Announcement						
f.	Project 2007-03 - Real-time Transmission Operations TOP-001-2 - Redline to Last Posting TOP-002-3 - Redline to Last Posting TOP-003-2 - Redline to Last Posting Implementation Plan - Clean PRC-001-2 - Redline to Last Approved Issues Database VRF and VSL Assignment Documentation - Redline to Last Posting PER-001-0.1 TOP-001-1 TOP-002-2a TOP-003-1 TOP-004-2 TOP-005-2 TOP-006-2 TOP-007-0 TOP-008-1 Mapping Document - Redline to Last Posting	Recirculation Ballots 4/27/12	5/6/12				

For the items in the preceding Comment Table:

Item 7a--Guy Zito discussed, and said that Con Edison's John Lim of the Drafting Team will call in to the Meeting May 3 to discuss. David Kiguel reported that is being reviewed, and there is nothing definitive yet. Howard Gugel said that each Standard will be balloted separately. Guy Zito expressed the hope that the RSC will be able to support

with the changes incorporated. Michael Lombardi, referring to CIP-004-5, questioned the use of role based training. He wants to stay with general training rather than role based. Referring to Requirement R7 addresses a 24 hour period to revoke access. As per FERC Order 706, Paragraph 463, transitional employees need privileges if transferred and still being required to handle duties of their previous positions. "Reassignment" and "transfer" key the need for a date. Needs clarification. Chris de Graffenried indicated that Con Edison will approve all the ballots. John Lim called in. Guy Zito asked how the approval of Version 4 will filter into Version 5. John Lim considers Version 5 to be a substantial improvement over Version 4. Review is still going on by TFIST. They hoped to resolve differences over their recommendations in the afternoon. The first filing of Version 5 to be done by the end of the first quarter 2013. There is a chance that Version 4 might be skipped. John Lim did not see a problem if Version 4 has to be dealt with before Version 5. There may have to be another 30 day posting. Guy Zito commented that if Version 4 is implemented before Version 5, black start and cranking path entities may have to make what will ultimately be unnecessary expenditures before Version 5 becomes effective. David Kiguel remarked that because it is unknown what will happen with Version 5, Version 4 will have to be complied with. The issue is that Version 4 will be enforceable April 1, 2014. Work has to begin before that date to achieve compliance. Worried about spending money needlessly. The ESP (electronic security perimeter) has been reinstated because of comments received. Guy Zito mentioned that this will be a topic at the upcoming Standards and Compliance Workshop. There will be a presentation, and classroom sessions. These are opinions, not basis for compliance.

Item 7c--The comments that Pedro Rebellon provided will be submitted.

Item 7d--Feelings from entities outside NPCC have been expressed that the ERO, and RE shouldn't be in the Applicability Section. Guy Zito expressed agreement with that position. The assembled reviewed EOP-004-2, and Ralph Rufrano's comments. Lee Pedowicz is to put together a Comment Form using Ralph Rufrano's comments. Guy Zito asked the RSC to let him know their ballot positions by May 11, 2012.

Item 7e--Guy Zito started the discussion by saying that a standard is meant to achieve an adequate level of reliability. Diane Barney did not feel that items 4 and 5 in the document should not be included, and footnote 1 of the document should be looked at. Diane Barney will send comments. Mike Garton felt that the document goes beyond creating a definition. John Pearson (ISO-NE) joined the discussion via the telephone conference. Following refers to the Definition: Adequate Level of Reliability for the Bulk Electric System document.

- Items 2 and 3--What is meant by the use of the word "satisfied"?
- Item 3--"Normal operating conditions" should not be part of the definition because normal means that an adequate level of reliability is already being achieved. Normal voltages are maintained during normal operating conditions.
- Item 4--Insert "reliability" before "demands.
- Item 5--Insert "reliability" before "demands". Remove "obligations", and insert "system" before "load".
- Item 6--Discussed.

- Item 7--The use of "restores supply to load" introduces cranking paths into any BES definition.

The RSC was asked to provide comments to Lee Pedowicz by the end of May.

Item 7f--Recirculation ballot.

8. Drafting Team Nominations Open (Current and between RSC Meetings)

a.				

Item 8--No nominations open.

9. NERC (in Meeting Materials Package)

a. Operating Committee Meeting--Standards related topics.
   1. March 6-7, 2012 meeting.

b. NERC Board of Trustees.
   1. March 14, 2012 conference call.
   2. May 8-9, 2012 Meeting.
      a. Report on Status of Regional Standards Development Programs.

c. Member Representatives Committee.
   1. May 8-9, 2012 Meeting. Report on Status of Regional Standards Development Programs.
   2. May 1, 2012 Webinar--Member Representatives Committee Informational Session Conference Call and Webinar. Agenda and Background Materials.
   3. Standards Process Input Group (SPIG)--improve reliability standards development process.

d. RSG.
   1. March 12, 2012 Meeting notes.
   2. Charter, proposed charter, comparison document.
   3. April 12, 2012 Meeting.

e. Standards Committee.
   1. April 11-12, 2012 Meeting.
      a. The SC reviewed the BES Phase2 SAR and Project Schedule. The SC accepted the Phase 2 SAR for development and approved the Project Schedule.
   2. Special Election Segment 5--only members of Segment 5 of the Registered Ballot Body, or their proxies, are eligible to vote. Ballot closes May 7, 2012.

f. System Analysis and Modeling Subcommittee Meeting April 17-18, 2012.

g. Other
   1. 2012 Standards and Compliance Workshops:
      October 23-25, 2012--Westin Buckhead in Atlanta, Georgia
   2. Standards Development Project Candidates. Comments sought.
   3. Actively Monitored List Update.
      a. April 5, 2012.
   4. NERC Related Matters.
      a. April 10, 2012--Of interest, Item 2 therein--NERC Standards Report, Status and Timetable for Addressing Regulatory Directives (RR09-6).

5. FAC Alert Recommendation Update Webinar--March 20, 2012. Participant Question and Answers.
6. Standards Oversight and Technology Committee Meeting--May 8, 2012.

h. System Protection and Control Subcommittee--April 24-26, 2012 Meeting. (Addressed Item 7cComents above [Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for SPCS]).

Item 9a--Guy Zito discussed Item 2 on page 1 of the NERC Operating Committee Meeting Notes from March 6 and 7, 2012. Regarding the CIP Version 5 Standards, Howard Gugel mentioned that if black start resources are left medium, generators would take them off black start. He believes that black start and cranking paths were changed from medium to low. Some facilities that affected by the designation were built before computer controls, and don't use them.

Item 9b--Guy Zito discussed. For Item 9b2 in particular, Guy Zito said the MRC's Standards Process Input Group was a good concept in that it would bring in technical expertise to the process. Also for Item 9b2, David Kiguel contributed to the discussion.

Item 9c2--Guy Zito discussed. The Drafting Team wants to complete the BES work in 18 months.

Item 9d--Guy Zito discussed.

Item 9e--David Kiguel remarked that Guy Zito presented the CEAP. It is to be posted to the industry for a 60 day comment period.

Addressed ANSI requirements regarding ballots, what to do with negative ballots with comments, and what to do with negative ballots without comments. Some entities don't have the resources to submit comments. Should they be included as a submitter with the others? Should "No" votes without comments be counted? Guy Zito asked how do you encourage someone who wants to submit a "No" vote to give comments. Diane Barney suggested having an E-mail sent automatically to a person voting "No". Howard Gugel said that that opportunity already exists when casting a ballot. David Kiguel discussed options for fixing BAL-002-0 R4. If there is a reliability related problem that needs fixing, fix it in the most expeditious manner. Participants are being looked for from NPCC to work on how to address cold weather problems.

Item 9e2--For information.

Item 9f--Addressing the definition of SPS. The RSC will follow. Will affect Directory #7, and may necessitate a regional standard for SPS approvals.

Item 9g1--There is a conflict with the October, 2012 RSC Meeting. Because of RSC members wanting to attend the NERC Workshop, Guy Zito said that he and Lee Pedowicz will look at the possibilities of rescheduling the RSC Meeting, or cancelling it. It was noted that there is a RSC Meeting scheduled for Nov. 29-30, 2012.

Item 9g2--Standards Project Prioritization. There will be a posting in August for prioritizations, and comments. The current posting is for advance notice. There were no RSC comments on this posting, which were due May 11, 2012.

Item 9g3--For information.

Items 9g4 through 9h--Discussed.

10. NERC Compliance Application Notices (CANs) For Industry Review (in Meeting Materials Package)

CANs Reviews Completed--See Appendix E

a. CAN-0008 PRC-005-1 Requirement R2--High-Level Review request. High-Level Review process began on February 24, 2012.
   1. Trade Groups High-Level Review Request of CAN-0008
   2. NERC CEO High-Level Review Response
   3. Remanded CAN-0008 PRC-005 R2 Basis for First Maintenance and Testing Date

b. CAN Prioritization.

c. CAN Process (redline). Comments/suggestions can be submitted any time.

d. Should the RSC be reviewing RSAWs?

Item 10a1--Discussed. Concerns had been addressed by NERC.

Item 10b--Guy Zito discussed.

Item 10c--Mike Jones said that after NERC is satisfied with a CAN they expose it to the industry.

Item 10d--Guy Zito remarked that NERC will start posting RSAWs for comments. Michael Lombardi said that Northeast Utilities agrees with National Grid's (Mike Jones) comments on the RSAWs. Greg Campoli said that the same position is held by the ISOs. This has been discussed with Gerry Cauley. The desire is to get away from check box type audits, and move towards a controls type of audit. Auditors will need to be trained. It was asked when will this go into effect? An auditor gets material before he gets onsite, then addresses any issues. Is this addressing internal controls? Guy Zito remarked that what is going on with the RSAWs will have to be watched. Howard Gugel said than a RSAW will be issued when a standard is posted for comments. David Kiguel said that Mike Moon had said that RSAWs shouldn't address internal controls. Will an entity be held accountable for not meeting internal controls? Guy Zito questioned how thorough, or how deep should an audit go. Internal control to be part of culture and compliance. Mike Jones discussed the RSAWs presentation slides. Control questions should not be in RSAWs. The RSC

Scope is to be changed to reflect how RSC will consider RSAWs. Proposal that the RSC will review RSAWs. Not all RSAWs will have to be reviewed. Comments will only be submitted if something is wrong. How to manage? Preliminary screening by a smaller group, then send out if necessary.

	CAN Final Version -- Table 1	**Industry Comment Analysis Spreadsheet** (ctrl+click)	**Comment Analysis Summary** (ctrl+click)	**Industry Comment Redline** (ctrl+click)	**Industry Comments Received** (ctrl+click)
1.					

	Draft CANs--Table 2	**Industry Comment Analysis Spreadsheet** (ctrl+click)	**Comment Analysis Summary** (ctrl+click)	**Industry Comments Received** (ctrl+click)	**Industry Comment Redline** (ctrl+click)
1.	CAN-0019 CIP-007 R3.2 Implementation of Software Security Patches or Upgrades--Comments due 6/4/12 on Comment Form and send to cancomments@nerc.net				
2.	CAN-0023 CIP-005 R3 CIP-006 R6 Logging System Failures--Comments due 6/4/12 on Comment Form and send to cancomments@nerc.net				
3.	CAN-0034 EOP-002 R1 IRO-001 R2 and TOP-001 R1 Use of Authority Letters--Comments due 5/7/12				
4.	CAN-0038 PER-002 R4 Training Hours--Comments due 5/7/12				

Item 10 Table 2-3 (CAN-0034)--National Grid's comments were discussed. National Grid's comments will be used for the NPCC comment submission. Howard Gugel suggested that restriction shouldn't be to a specific list to show compliance.

Item 10 Table 2-4 (CAN-0038)--National Grid's comments were discussed. CANs are the wrong mechanism for defining time. Guy Zito commented that auditors need to be given guidance so they can be consistent in their performance of audits. Greg Campoli commented that he thought the CAN worked, but this issue would have been better addressed through an interpretation. Mike Jones' comments are addressing the process. The RSC agreed. This is a process issue, and should not be dealt with in a CAN.

11. NERC Standards Bulletins (link is to the current bulletin; in Meeting Materials Package)

a. NERC Standards Bulletin--March 12-18, 2012.
b. NERC Standards Bulletin--March 19-25, 2012.
c. NERC Standards Bulletin--March 26 - April 1, 2012.
d. NERC Standards Bulletin--April 2-8, 2012.
e. NERC Standards Bulletin--April 9-15, 2012.
f. NERC Standards Bulletin--April 16-22, 2012.
g. NERC Standards Bulletin--April 23-29, 2012.
h. NERC Standards Bulletin--April 30 - May 6, 2012.

Item 11--For information.

12. NPCC Regional Standards, and Related Items (in Meeting Materials Package)

a. Regional Reliability Standards Development Procedure.
b. PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding--anticipated second quarter FERC filing.
c. NPCC RSC Triage Process for Standards Related Matters.

Item 12a--Will be posted.

Item 12b--To be filed with FERC on or before May 7, 2012. When filed with FERC, it is also filed with Ontario.

Guy Zito--Lead a discussion of what happens with regional standards after NERC Board of Trustee approval. Regional or NERC standards will be found on the NERC Website. The effective date has to be done by NERC. NERC owns the filing and effective dates, and the display of those dates. For regional standards, if there is errata, a redline is to be made and then sent to Howard Gugel for him to handle.

Item 12c--Guy Zito lead the discussion. Wants to change the approach on how to solicit comments from members. Need to conduct a screening review of standards being posted for comment. Then develop a list of questions or issues to be addressed. RSC needs to take a more active role. Focus on issues, take an ownership role, have Webinars. Information will then be compiled and entered on a Comment Form. For the screening,

set up small groups to review. Who should review, and what resources are required must be identified. What can then be done to focus and move forward. A proposal was made to send the comment postings to the RCC Chair. Another proposal was to invite Task Forces to a conference call to discuss comment postings. A draft would then be put together and sent out. Guy Zito will put together a proposal for RSC consideration.

13. NPCC Directory and Regional Work Plan Status

a. Directory #6 Reserve Sharing Groups was posted for ballot March 14, 2012, approved April 6, 2012.
b. TFCP conference call April 17, 2012--Directory #1.
c. Directory Work Plan for Phase 2 Reformatting.

Item 13--Gerry Dunbar reported that on May 8, 2012 representatives from the RSC, CC, and TFSP will meet to discuss Directories #4, and #7 to get them moved into Phase 2. Directory #1 requires coordination between TFCP, and TFCO. There is concern that they are looking at different versions. TFCO is meeting on May 17, 2012. The Directory is not ready for posting. Hope to have it posted in 1-2 months. Directory #5 to be posted in 2-3 weeks.

14. New York Adoption of More Stringent/Specific NPCC Criteria

Item 14--In process is the development of a table listing the more stringent criteria.

15. Report on NERC, NAESB and Regional Activities (in Meeting Materials Package)
a. Monthly NERC, NAESB Regional Entity Update--March, 2012.
b. Monthly NERC, NAESB Regional Entity Update--April, 2012.

Item 15--For information.

16. Other
a. 2012 NERC Corporate Performance Measures.
b. NPCC's Regional Entity Ballot Process on NERC Standards.
c. Standard Driven Index (SDI) presentation for the March 14-15, 2012 CCC Meeting.
d. NERC Grid Exercise Increases Cybersecurity Readiness; Identifies Enhancements to Improve Security.
e. NERC News.
   1. March, 2012.
   2. April, 2012.
f. GMDTF Update.
g. TFCO Meeting Minutes--January 17-18, 2012.
h. MRO Standards Process Manual posted for ballot April 13, 2012 through April 23, 2012.
i. New York Energy Highway Initiative.

j. NPCC Board of Directors teleconference May 1, 2012.
k. Regional Approval Timelines.
l. The Midwest Reliability Organization move.
m. NERC cold weather study participants sought.
n. RCC April 30, 2012 teleconference Agenda and Materials. Modification of the Bruce Type I Special Protection System, and NPCC Reliability Assessment for Summer 2012.
o. NERC Draft 2013 Business Plan and Budget--Webinar May 3, 2012 10:00 a.m.

Item 16a--Guy Zito discussed.

Item 16b--Guy Zito discussed.

Item 16c--Diane Barney asked how the information is being gathered. Will a regional problem be diluted continent wide? Greg Campoli discussed. Is reliability improving?

Item 16d--For information.

Items 16e through 16j--For information.

Item 16k--Guy Zito discussed. Representatives from the Provinces to review. Gerry Dunbar will send out for comments.

Item 16l--For information.

Item 16m--For information. Bruce Metruck to send Guy Zito information.

Items 16n, 16o--For information.

Members reported that there is no confirmation sent when they register for a meeting on the NPCC Website.

Frantz Roc to check the RSCmembers distribution list is a subset of the RSC list.

Diane Barney made a motion to adjourn the meeting.
Michael Lombardi seconded the motion.

17. Meetings

RSC 2012 Meeting Dates

July 18-19, 2012 Day Pitney Offices Boston, Massachusetts	September 5-6, 2012 Hydro-Quebec Offices, Montreal
October 24-25, 2012 Toronto	November 29-30, 2012--Montreal (NPCC General Meeting)

2012 RSC Conference Call Schedule

(call 719-785-1707, Guest Code 8287#)

May 18, 2012	August 3, 2012	October 12, 2012
June 1, 2012	August 17, 2012	November 9, 2012
June 15, 2012	August 31, 2012	December 14, 2012
June 29, 2012	September 14, 2012	December 28, 2012
July 13, 2012	September 28, 2012	

BOD 2012 Meeting Dates

June 26, 2012--NPCC Offices
August 7, 2012 (Teleconference)
September 19, 2012--NPCC Offices
October 30, 2012 (Teleconference)
November 28, 2012--Montreal, Quebec

RCC, CC, and Task Force Meeting Dates--2012

RCC	June 13, Sept. 12, Nov. 27
CC	5/16 (Conference Call), 6/7-8 (NU, Berlin, Conn.), 7/17 (Conference Call), 8/15 (Conference Call), 9/13-14 (NPCC Offices, NYC), 10/17 (Conference Call), 11/29-30 (Montreal, Joint with RSC)
TFSS	
TFCP	May 9, August 15, Nov. 7
TFCO	May 16, August 30, October 17, November 29
TFIST	
TFSP	May 15-16, July 17-19, September 18-19, November 13-14

Item 17--Refer to the notes for Item 9g1.

The November, 2012 RSC Meeting will be held at the Hotel Omni Mont-Royal.

Meeting adjourned May 2, 2012 3:56 p.m.
Meeting adjourned May 3, 2012 at 12:34 p.m.

Respectfully Submitted,

Guy V. Zito, Chair RSC
Assistant Vice President-Standards
Northeast Power Coordinating Council Inc.

Appendix A

Northeast Power Coordinating Council, Inc. (NPCC)
Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment. Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Andrianne S. Payson at 212-259-8218.

Appendix B (Item 3)

Action Item List

Date	Action Item Number	Description	Owner	Due	Status
April 21-22, 2010	63	Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Outgrowth of RSC/CC joint session April 21, 2010. Joint RSC/CC Meeting this meeting.

Appendix C (Item 8)

Concluded Ballots (in Meeting Materials Package)

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
a.	Project 2010-11 - TPL Table 1, Footnote B	Recirculation Ballot	1/26/11	2/5/11	Quorum: 93.61% Approval: 86.54%	Yes 1/5/11
b.	Project 2007-07 - Vegetation Management - FAC-003	Successive Ballot and Non-Binding Poll	2/18/11	2/28/11	Quorum: 79.28% Approval: 79.34%	Yes 2/22/11
c.	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/11	3/7/11	Quorum: 87.10% Approval: 49.54%	Yes 3/2/11
d.	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/11	2/18/11	Ballot Pool: 310 Opinions: 141 72% Support	Yes 10/28/10

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
e.	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot and Non-Binding Poll	1/24/11	2/13/11	Quorum: 83.95% Approval: 65.71%	Yes 2/11/11
f.	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/11	3/6/11	Quorum: 87.35% Approval: 68.83%	Yes 2/11/11
g.	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Successive Ballot and Non-Binding Poll	4/19/11	4/28/11	Quorum: 79.66% Approval: 38.00%	No 4/19/11
h.	Project 2009-06 - Facility Ratings	Cast Ballot	4/21/11	5/2/11	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11
i.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Successive Ballot and Non-Binding Poll	5/3/11	5/12/11	Quorum: 78.33% Approval: 67.00%	No Recommendation
j.	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	Recirculation Ballot	5/12/11	5/23/11	Quorum: 91.25% Approval: 78.92%	Yes 5/12/11
k.	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot and Non-Binding Poll	5/18/11	5/31/11	Quorum: 92.07% Approval: 73.99	----
l.	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	Initial Ballot and Non-Binding Poll	5/31/11	6/9/11	Quorum: 88.47% Approval: 48.64%	Reject 5/31/11
m.	Project 2007-09 – Generator Verification – MOD-026-1 Ballot Results Revised because of NERC IT problem	Cast Ballot	7/22/11	8/1/11	Quorum: 90.25% Approval: 46.53%	No Consensus 7/28/11
n.	Project 2007-09 – Generator Verification – MOD-026-1	Cast Non-Binding Poll Opinion	7/22/11	8/1/11	Quorum: 88.75% Approval: 56.00%	----

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
o.	Project 2007-09 – Generator Verification – PRC-024-1 Ballot Results Revised because of NERC IT problem	Cast Ballot	7/22/11	8/1/11	Quorum: 90.82% Approval: 18.23%	No Consensus 7/28/11
p.	Project 2007-09 – Generator Verification – PRC-024-1	Cast Non-Binding Poll Opinion	7/22/11	8/1/11	Quorum: 88.35% Approval: 20.79%	----
q.	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot and Non-Binding Poll	6/20/11	6/30/11	Quorum: 82.97% Approval: 64.76%	Yes 6/28/11
r.	Project 2006-02 - Assess Transmission and Future Needs	Cast Ballot	7/13/11	7/22/11	Quorum: 94.33% Approval: 75.37%	----
s.	Project 2006-06 - Reliability Coordination - IRO-002-3	Cast Ballot	7/15/11	7/25/11	Quorum: 94.13% Approval: 76.99%	Yes 7/22/11
t.	Project 2006-06 - Reliability Coordination - IRO-005-4	Cast Ballot	7/15/11	7/25/11	Quorum: 94.13% Approval: 75.17%	Yes 7/22/11
u.	Project 2006-06 - Reliability Coordination - IRO-014-2	Cast Ballot	7/15/11	7/25/11	Quorum: 94.13% Approval: 76.27%	Yes 7/22/11
v.	Project 2006-06 - Reliability Coordination - IRO-002-3	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: 75.37% Approval: 93%	----
w.	Project 2006-06 - Reliability Coordination - IRO-005-4	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: 75.66% Approval: 93%	----
x.	Project 2006-06 - Reliability Coordination - IRO-014-2	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: 75.37% Approval: 89%	-----

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
y.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Initial Ballot	9/19/11	9/28/11 9/29/11-- Technical Difficulties	Quorum: 84.86% Approval: 61.10%	Yes 9/21/11
z.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Non-Binding Poll VRFs and VSLs	9/19/11	9/28/11 9/29/11-- Technical Difficulties	Quorum: 83.13% Approval: 68.68%	----
aa.	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	Initial Ballot	9/30/11	10/10/11	Quorum: 92.97% Approval: 71.68%	No Consensus 10/3/11
bb.	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Detailed Information to Support BES Exceptions Request	Initial Ballot	9/30/11	10/10/11	Quorum: 89.53% Approval: 64.03%	No Consensus 10/7/11
cc.	Project 2007-07 - Vegetation Management	Recirculation Ballot	10/4/11	10/13/11	Quorum: 87.17% Approval: 86.25%	Yes 2/22/11
dd.	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Initial Ballot	11/7/11	11/16/11	Quorum: 88.05% Approval: 85.53%	Yes 11/8/11
ee.	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Initial Ballot	11/8/11	11/17/11	Quorum: 91.2% Approval: 95.05%	Yes 11/8/11
ff.	Project 2010-07 - Generator Requirements at the Transmission Interface-- FAC-001-1	Initial Ballot	11/9/11	11/18/11	Quorum: 88.22% Approval: 86.94%	Yes 11/10/11
gg.	Project 2010-07 - Generator Requirements at the Transmission Interface-- FAC-003-3	Initial Ballot	11/9/11	11/18/11	Quorum: 85.08% Approval: 85.71%	Yes 11/10/11
hh.	Project 2010-07 - Generator Requirements at the Transmission Interface-- FAC-003-X	Initial Ballot	11/9/11	11/18/11	Quorum: 84.82% Approval: 85.31%	Yes 11/10/11

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
ii.	Project 2010-07 - Generator Requirements at the Transmission Interface--PRC-004-2.1	Initial Ballot	11/9/11	11/18/11	Quorum: 84.29% Approval: 96.09%	Yes 11/10/11
jj.	Project 2010-17 - Definition of Bulk Electric System and Implementation Plan	Recirculation Ballot	11/10/11	11/21/11	Quorum: 95.92% Approval: 81.32%	Yes 10/3/11
kk.	Project 2010-17 - Detailed Information to Support an Exception Request	Recirculation Ballot	11/10/11	11/21/11	Quorum: 93.02% Approval: 81.48%	Yes 10/3/11
kk1.	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Successive Ballot	11/11/11	11/21/11	Quorum: 83.53% Approval: 95.99%	Yes 11/14/11
ll.	Project 2007-12 - Frequency Response	Initial Ballot and Non-Binding Poll	11/30/11	12/9/11	Quorum: 93.92% Approval: 30.82%	No 12/5/11
mm.	Project 2009-01 - Disturbance and Sabotage Reporting - CIP-001 and EOP-004	Initial Ballot and Non-Binding Poll	12/2/11	12/12/11	Quorum: 87.97% Approval: 36.21%	No 12/5/11
nn.	Project 2008-06 - Cyber Security - Order 706 - CIP-002 through CIP)-009 (Version 5 CIP Standards	Initial Ballots Please Vote for each of the 10 CIP Standards Separately	12/16/11	1/6/11	See Table below	No 12/16/11

For Item nn above--

CIP-002-5 Cyber Security — BES Cyber System Identification	Quorum: 93.62% Approval: 22.09%
CIP-003-5 Cyber Security — Security Management Controls	Quorum: 93.62% Approval: 33.49%
CIP-004-5 Cyber Security — Personnel and Training	Quorum: 93.62% Approval: 26.82%
CIP-005-5 Cyber Security — Electronic Security Perimeter(s)	Quorum: 93.62% Approval: 28.04%
CIP-006-5 Cyber Security — Physical Security	Quorum: 93.61% Approval: 29.60%
CIP-007-5 Cyber Security — Systems Security Management	Quorum: 93.61% Approval: 24.15%
CIP-008-5 Cyber Security — Incident Reporting and Response Planning	Quorum: 94.02% Approval: 34.30%
CIP-009-5 Cyber Security — Recovery Plans for BES Cyber Assets and Systems	Quorum: 93.61% Approval: 27.28%
CIP-010-1 Cyber Security — Configuration Change Management	Quorum: 93.61% Approval: 26.61%
CIP-011-1 Cyber Security — Information Protection	Quorum: 93.61% Approval: 29.88%
CIP V5 Implementation Plan	Quorum: 92.15% Approval: 42.06%
CIP V5 Definitions	Quorum: 92.56% Approval: 25.34%

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
oo.	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Recirculation Ballot	12/12/11	12/22/11	Quorum: 90.10% Approval: 92.49%	Yes 11/8/11
pp.	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Recirculation Ballot	12/14/11	12/23/11	Quorum: 92.00% Approval: 94.58%	Yes 11/8/11
qq.	Project 2010-07 - Generator Requirements at the Transmission Interface--PRC-004-2.1 FAC-001-1 FAC-003-3 FAC-003-X PRC-004-2.1a	Recirculation Ballot	12/14/11	12/23/11	Quorum: 88.48% Approval: 90.10% Quorum: 87.17% Approval: 85.38% Quorum: 86.91% Approval: 85.03% Quorum: 86.65% Approval: 96.43%	Yes 11/10/11

rr.	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2 TOP-001-2 TOP-002-3 TOP-003-2	Successive Ballots	1/3/12	1/12/12	Quorum: 82.04% Approval: 59.93% Quorum: 82.04% Approval: 77.08% Quorum: 82.04% Approval: 78.95%	1/9/12 TOP-001-2--No TOP-002-3--Yes TOP-003-2--Yes
ss.	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Recirculation Ballot	12/9/11	12/19/11	Quorum: 88.02% Approval: 96.04%	Yes 11/14/11
tt.	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2 TOP-001-2 TOP-002-3 TOP-003-2	Non-Binding Polls	1/9/12	1/18/12 Extended to 1/19/12	Quorum: 81.50% Approval: 67.61% Quorum: 76.41% Approval: 71.42% Quorum: 81.50% Approval: 70.28%	----
uu.	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	Successive Ballots and Non-Binding Polls	1/30/12	2/8/12 Changed to 2/9/12	Quorum: Approval:	2/7/12 COM-001-02--No COM-002-3--Yes IRO-001-3--Yes
vv.	Project 2010-07 - Generator Requirements at the Transmission Interface--PRC-004-2.1	Non-Binding Poll	1/4/12	1/13/12	Quorum: 78.27% Approval: 93.00%	----

ww.	Project 2009-26 - Interpretation of CIP-004-1 by WECC		Successive Ballot	3/14/12	3/23/12	Quorum: 88.55% Approval: 79.61%	Yes 3/16/12
xx.	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy		Initial Ballot	3/14/12	3/23/12	Quorum: 89.63% Approval: 94.71%	Yes 3/16/12
yy.	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation		Initial Ballot	3/14/12	3/23/12	Quorum: 86.92% Approval: 63.09%	Yes 3/16/12
zz.	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3		Successive Ballots	3/30/12	4/9/12	Yes 4/5/12	
	FAC-003-3	Quorum: 80.37% Approval: 85.18%					
	FAC-003-X	Quorum: 80.10% Approval: 85.01%					
aaa.	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a		Initial Ballot	4/6/12	4/16/12	Quorum: 88.95% Approval: 92.41%	Yes 4/16/12
bbb.	Project 2007-03 - Real-time Transmission Operations - TOP-001 through TOP-008 and PER-001		Successive Ballots	4/11/12	4/20/12	Quorum: Approval:	
ccc.	Project 2007-17 Protection System Maintenance and Testing - PRC-005		Successive Ballot	3/19/12	3/28/12	Quorum: Approval:	Yes 3/19/12

ddd.	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1		Successive Ballot	3/19/12	3/29/12	Yes 3/19/12
	MOD-026-1	Quorum: 80.82% Approval: 61.25%				
	PRC-024-1	Quorum: 79.75% Approval: 40.99%				
eee.	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1 Announcement			4/6/12	4/16/12	Yes 4/16/12
		Initial Ballot	Non-binding Poll Results			
	MOD-025-2	Quorum: 88.28% Approval: 41.09%	Quorum: 86.82% Supportive Opinions: 43.72%			
	MOD-027-1	Quorum: 88.04% Approval: 36.84%	Quorum: 86.04% Supportive Opinions: 38.56%			
	PRC-019-1	Quorum: 88.04% Approval: 48.70%	Quorum: 86.53% Supportive Opinions: 46.38%			

fff.	Project 2007-03 - Real-time Transmission Operations		Successive Ballots	4/11/12	4/20/12		TOP-001 Abstain 4/19/12 TOP-002 Yes 4/19/12 TOP-003 Yes 4/19/12
	TOP-001-2	Quorum: 78.28% Approval: 75.65%					
	TOP-002-3	Quorum: 78.02% Approval: 87.22%					
	TOP-003-2	Quorum: 78.28% Approval: 80.11%					
ggg.						Quorum: Approval:	
hhh.						Quorum: Approval:	

Appendix D (Item 8)

Comment Forms Submitted (in Meeting Materials Package)

a.	Standards Project Prioritization Reference Document and Tool	Comment Form	1/21/11	2/10/11
b.	Project 2007-12 - Frequency Response	Comment Form	2/4/11	3/7/11
c.	Project 2007-07 - Vegetation Management - FAC-003	Comment Form	1/27/11	2/28/11
d.	Project 2007-23 - Violation Severity Levels	Comment Form	1/20/11	2/18/11
e.	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Comment Form	1/18/11	3/7/11
f.	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	Comment Form (no comments submitted)	1/10/11	2/24/11
g.	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	Comments	2/4/11	2/18/11
h.	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	Comments	2/4/11	2/18/11

i.	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	Comments	2/11/11	3/4/11
j.	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	Comments	2/4/11	2/18/11
k.	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	Comments	2/14/11	3/7/11
l.	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	Comment Form	3/17/11	5/2/11
m.	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	Comment Form	3/29/11	4/28/11
n.	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Comment Form	2/16/11	4/4/11
o.	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments	Comments (No comments submitted)	3/1/11	4/15/11
p.	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Comments	3/1/11	4/15/11
q.	Project 2010-07 - Generator Requirements at the Transmission Interface	Informal Comment Period	3/4/11	4/4/11
r.	Project 2009-01 - Disturbance and Sabotage Reporting	Comment Form	3/9/11	4/8/11
s.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Comment Form	4/13/11	5/12/11
t.	Project 2010-17 - Definition of Bulk Electric System	Comment Form	4/28/11	5/27/11
u.	Project 2006-02 - Assess Transmission and Future Needs	Comment Form	4/18/11	5/31/11
v.	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	Comment Form	4/26/11	6/9/11
w.	Project 2010-17 - Definition of Bulk Electric System	Comment Form	5/11/11	6/10/11
x.	Rules of Procedure Development Team: BES Definition Exception Process	Comment Form	5/11/11	6/10/11
y.	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	Comments	5/20/11	6/10/11
z.	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	Comments	5/20/11	6/10/11
aa.	CAN-0030--Draft CAN-0030 Attestations	Comments	5/20/11	6/10/11
bb.	CAN-0039--Draft CAN-0039 DOE Form 407	Comments	5/20/11	6/10/11

cc.	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)	Comment Form	6/10/11	7/11/11
dd.	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	Comment Form	6/15/11	7/15/11
ee.	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	Comment Form	6/15/11	8/1/11
ff.	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Comment Form	6/17/11	7/17/11
gg.	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Sent Comments to ROPcomments@nerc.net	6/30/11	8/15/11
hh.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Comment Form	8/15/11	9/29/11 (Extended from 9/28/11 because of NERC network problems)
ii.	Compliance Application Notice (CAN) Process	Comment Form	8/15/11	9/6/11
jj.	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	Comment Form	8/15/11	9/6/11
kk.	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	Comment Form	8/26/11	10/10/11
mm.	Proposed Changes to NERC Rules of Procedure and All Appendices	Sent Comments to cancomments@nerc.net No Comments Submitted	9/2/11	10/17/11
nn.	NERC 2012-2014 Reliability Standards Development Plan	Comment Form	9/12/11	9/26/11
oo.	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004 (See note below table)	Sent Comments to cancomments@nerc.net	8/31/11	9/21/11
pp.	New CAN Template, five DRAFT CANs for Industry review, and CANs Status posted to NERC Compliance's Web site.	Sent Comments to cancomments@nerc.net	9/23/11	10/14/11

qq.	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	Comment Form	9/13/11	10/27/11
rr.	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Comment Form	10/3/11	11/16/11
ss.	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Comment Form	10/4/11	11/17/11
tt.	Project 2010-07 - Generator Requirements at the Transmission Interface	Comment Form	10/5/11	11/18/11
uu.	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	Sent Comment Form to cancomments@nerc.net	10/19/11	11/9/11
vv.	CAN-0030--Attestations	No Comments	10/19/11	11/9/11
ww.	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Comment Form	10/12/11	11/21/11
xx.	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
yy.	CAN-0011--PRC-005-1 R2: New Equipment	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
zz.	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
aaa.	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	No Comments	10/10/11	10/31/11
bbb.	CAN-0015--Unavailability of NERC Software Tools	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
ccc.	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	No Comments	10/10/11	10/31/11
ddd.	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
eee.	CAN-0026--TOP-006 R3 Protection Relays	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11

fff.	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	No Comments	10/10/11	10/31/11
ggg.	Draft Directive Regarding Generator Transmission Leads (comments also submitted by CC)	Comments forwarded to NERC Staff: Jim Hughes, Jack Wiseman, Stacia Ann-Chambers	10/17/11	11/18/11 (originally 11/15/11)
hhh.	CAN-000040 - BAL-003 Frequency Bias Calculation	No Comments	11/2/11	11/23/11
iii.	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	Comment Form (submitted to cancomments@nerc.net)	11/2/11	11/23/11
jjj.	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	No Comments	11/22/11	12/14/11
kkk1.	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Comment Form	11/7/11	1/6/12
lll.	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	Comment Form	12/14/11	1/12/12
mmm.	Proposed Changes to the NERC Rules of Procedure and Associated Appendices	No Comments	11/7/11	12/22/11
nnn.	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011	No Comments	11/22/11	12/22/11
ooo.	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding (NPCC Website Link)	No Comments	11/22/11	12/22/11
ppp.	Order 754 - Request for Data or Information	Comment Form	12/22/11	2/6/11
qqq.	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Comment Form	1/4/12	2/3/12
rrr.	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	Comment Form	1/9/12	2/8/12 Date Changed to: 2/9/12
sss.	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	No Comments	1/23/12	3/9/12

ttt.	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	No Comments	1/23/12	3/9/12
uuu.	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Comment Form	2/8/12	3/23/12
vvv.	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Comment Form	2/8/12	3/23/12
www.	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	Comment Form	2/8/12	3/23/12
xxx.	NERC Functional Model Demand Response Functions and Entities	No Comments	2/13/12	3/14/12
yyy.	Project 2007-17 Protection System Maintenance and Testing - PRC-005	Comment Form	2/28/12	3/28/12
zzz.	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1	Comment Form	2/29/12	3/29/12
aaaa.	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1	Comment Form	2/29/12	4/16/12
bbbb.	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3	Comment Form	3/9/12	4/9/12
cccc.	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a	Comment Form	3/2/12	4/16/12
dddd.	Project 2007-03 - Real-time Transmission Operations	Comment Form	3/22/12	4/20/12

Appendix E (Item 11)

NERC Compliance Application Notices (CANs) For Industry Review

	CAN Final Version -- Table 1	**Industry Comment Analysis Spreadsheet** (ctrl+click)	**Comment Analysis Summary** (ctrl+click)	**Industry Comment Redline** (ctrl+click)	**Industry Comments Received** (ctrl+click)
1.	CAN-0006: EOP-005 R7 Verification of Restoration Procedure (Revised)	AA1	BB1	CC1	
2.	CAN-0009: FAC-008 and FAC-009 Facility Rating and Design Specifications (Revised)	DD1	EE1	FF1	
3.	CAN-0017: CIP-007 R5 Technical and Procedural System Access and Password Controls	GG1	HH1	II1	
4.	CAN-0018: FAC-008 R1.2.1 Terminal Equipment (Revised)	JJ1	KK1	LL1	
5.	CAN-0008: PRC-005 R2 Basis for First Maintenance and Testing Date (Revised)	MM1	NN1	OO1	
6.	CAN-0010: Implementation of Annual in Reliability Standard Requirements (Revised)	PP1	QQ1	RR1	
7.	CAN-0011: PRC-005 R2 Interval Start Date for New Equipment (Revised)	SS1	TT1	UU1	
8.	CAN-0012: Completion of Periodic Activity Requirements During Implementation Plan (Revised)	VV1	WW1	XX1	

	CAN Final Version -- Table 1	**Industry Comment Analysis Spreadsheet** (ctrl+click)	**Comment Analysis Summary** (ctrl+click)	**Industry Comment Redline** (ctrl+click)	**Industry Comments Received** (ctrl+click)
9.	CAN-0013: PRC-023 R1 And R2 Effective Dates for Switch-On-To-Fault Schemes (Revised)	YY1	ZZ1	AAA1	
10.	CAN-0028: TOP-006 R1.2 Reporting Responsibilities (Revised)	BBB1	CCC1	DDD1	
11.	CAN-0005: CIP-002 R3 Critical Cyber Asset Designation for System Operator Laptops (Revised)	EEE1	FFF1	GGG1	
12.	CAN-0007: CIP-004 R4.2 Revocation of Access to Critical Cyber Assets (Revised)	HHH1	III1	JJJ1	
13.	CAN-0015: Unavailability of NERC Software Tools (Revised) It was determined that the SDT Project 2009-02: Real-Time Reliability Monitoring and Analysis Capabilities that was mentioned in CAN-0015 does not cover the material in this CAN; thus, that reference was removed.	KKK1	LLL1	MMM1	
14.	CAN-0022: VAR-002 R1 and R3: Generator AVR Operation in Alternative Mode (Revised)	NNN1	OOO1	PPP1	

	CAN Final Version -- Table 1	**Industry Comment Analysis Spreadsheet** (ctrl+click)	**Comment Analysis Summary** (ctrl+click)	**Industry Comment Redline** (ctrl+click)	**Industry Comments Received** (ctrl+click)
15.	CAN-0026: TOP-006 R3 Protective Relays (Revised)	QQQ1	RRR1	SSS1	
16.	CAN-0029: PRC-004 R1 – R3 Protection System Misoperations	TTT1	UUU1	VVV1	
17.	CAN-0030: Attestations (See Item 4 in Table 2 following)	WWW1	XXX1	YYY1	
18.	CAN-0031: CIP-006 R1 Acceptable Opening Dimensions	ZZZ1	AAAA1	BBBB1	
19.	CAN-0039: EOP-004 R3 Filing DOE Form OE-417 Event Reports	CCCC1	DDDD1	EEEE1	
20.	CAN-0020: TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Outages	FFFF1	GGGG1	HHHH1	
21.	CAN-0024: CIP-002 R3 Routable Protocols and Data Diode Devices	IIII1	JJJJ1	KKKK1	
22.	CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	LLLL1	MMMM1	NNNN1	OOOO1
23.	CAN-0040: BAL-003 Calculating Frequency Bias			PPPP1	
24.	CAN-0043: PRC-005 Protection System Maintenance and Testing Evidence			QQQQ1	

	Draft CANs--Table 2	**Industry Comment Analysis Spreadsheet** (ctrl+click)	**Comment Analysis Summary** (ctrl+click)	**Industry Comments Received** (ctrl+click)	**Industry Comment Redline** (ctrl+click)
1.	DRAFT CAN-0029: PRC-004 R1, R2 and R3 Protection System Misoperations	AA2	BB2		
2.	DRAFT CAN-0039: EOP-004-1 Filing DOE Form OE-417 Event Reports	CC2	DD2		
3.	DRAFT CAN-0031: CIP-006 R1 Acceptable Opening Dimensions	EE2	FF2		
4.	DRAFT CAN-0030: Attestations	GG2	HH2	II2	
5.	DRAFT CAN-0024: CIP-002 R3 Routable Protocols and Data Diode Devices	JJ2	KK2	LL2	LL22
6.	DRAFT CAN-0040: BAL-003 R2 and R5 Frequency Bias Calculation	MM2	NN2	OO2	
7.	DRAFT CAN-0043: PRC-005 Protection System Maintenance and Testing Evidence	PP2	QQ2	RR2	

Project No.	Project Title	DT Type	NPCC Representatives	Company	Telephone	E-mail Address	Comments
2006-02	Assess Transmission Future Needs & Develop Transmission Plans	Standard	Dana Walters	New York Independent System Operator	518-356-8582	dwalters@nyiso.com	
2006-02	Assess Transmission Future Needs & Develop Transmission Plans	Standard	Yury Tsimberg	Kinectrics	416-207-6000 X6106	Yury.Tsimberg@Kinectrics.com	Observer
2006-06	Reliability Coordination	Standard	Earl Barber	National Grid	315-428-5532	earl.barber@us.ngrid.com	
2006-06	Reliability Coordination	Standard	Allan D. Miller	Independent Electricity System Operator	905-855-6158	al.miller@ieso.ca	
2007-02	Operating Personnel Communications Protocols	Standard	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com	
2007-03	Real-time Operations	Standard	Phil Lavallee	National Grid	508-389-2827	phil.lavallee@us.ngrid.com	
2007-03	Real-time Operations	Standard	Karl Tammar - Vice Chair	Northeast Utilities			
~~2007-06~~	~~System Protection Coordination~~	~~Standard~~	~~Aaron Cooperberg~~	~~Hydro One Networks~~	~~416-345-5172~~	~~cooperberg@HydroOne.com~~	
2007-06	System Protection Coordination	Standard	David Cirka	National Grid	781-907-3240	david.cirka@us.ngrid.com	
2007-07	Vegetation Management	Standard	Dave Morrell	New York State Dept of Public Svc	518-486-7322	david_morrell@dps.state.ny.us	
2007-08	Vegetation Management	Standard	Orville Cocking	Con Edison			
~~2007-07~~	~~Vegetation Management~~	~~Standard~~	~~George Czerniewski~~	~~Con Edison~~			
2007-09	Generator Verification	Standard	Les Hajagos	Kestrel Power Engineering Ltd.	905-272-2191	les@kestrelpower.com	
~~2007-12~~	~~Frequency Response~~	~~Standard~~	~~Harvey Happ~~	~~New York State Dept of Public Svc~~	~~518-486-2939~~	hhh@dps.state.ny.us	
2007-12	Frequency Response	Standard	Mike Potishnak	ISO-NE	413-535-4308	mpotishnak@iso-ne.com	
2007-17	Protection System Maintenance & Testing	Standard					
	CIP Interpretations	Interpretation	Mark Engels	Dominion	804-775-5263	mark.engels@dom.com	
2008-06	Cyber Security for Order 706	Standard	John Lim	Con Edison	212-460-2712	limj@coned.com	Chair
2008-06	Cyber Security for Order 706	Standard	Rene Bourassa	Hydro Quebec - TransEnergie	514.858.8500		
2008-06	Cyber Security for Order 706	Standard	Doug Johnson	Exelon-Commonwealth Edison	630-691-4593	douglas.johnson@comed.com	
2008-06	Cyber Security for Order 706	Standard	Robert Antonishen	Ontario Power Generation	905-262-2674	rob.antonishen@opg.com	
2008-06	Cyber Security for Order 706	Standard	Thomas Stevenson	Constellation Energy	410-787-5260	thomas.w.stevenson@constellation.com	
2009-01	Disturbance and Sabotage Reporting	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com	Vice-Chair
2009-01	Disturbance and Sabotage Reporting	Standard	Michelle Draxton	Constellation Energy Group	410-474-2993	Michelle.l.draxton@constellation.com	
2009-01	Disturbance and Sabotage Reporting	Standard	Drew Phillips	IESO	905-855-4114	drew.phillips@ieso.ca	
~~2009-01~~	~~Disturbance and Sabotage Reporting~~	~~Standard~~	~~Thomas J Curran~~	~~Con Edison~~	~~347-672-4621~~	currant@coned.com	
2009-22	Interpretation of COM-02-2	Interpretation	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com	
2010-05	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One	647-328-7068	paul.difilippo@hydroone.com	
2010-05	Protection Systems: Phase 1 (Misoperations)	Standard	Richard A. Purdy	Dominion Virginia Power			
2010-05	Protection Systems: Phase 1 (Misoperations)	Standard	Tim Seeber	ComEd/Exelon			
2010-07	Generator Requirements at the Transmission Interface	SAR	Louis Slade	Dominion			
2010-14	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard	Michael Potishnak	ISO-New England	413-535-4308	mpotishnak@iso-ne.com	
2010-14	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard	Guy Quintin	Hydro Quebec - TransEnergie	514-289-2211 X3150	Quintin.Guy@hydro.qc.ca	
2010-14	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard	Jerry Rust	NPCC			
2010-17	Definition of Bulk Electric System	Standard	Jennifer Dering	NYPA		Jennifer.Dering@nypa.gov	
2010-17	Definition of Bulk Electric System	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com	
2010-17	Definition of Bulk Electric System	Standard	Phil Fedora	NPCC	212-840-4909	pfedora@npcc.org	
2010-17	Definition of Bulk Electric System	Standard	Ajay Garg	Hydro One Networks	416.345.5420	ajay.garg@HydroOne.com	
2010-17	Definition of Bulk Electric System	Standard	Jennifer T. Sterling	Exelon			
2010-17	Definition of Bulk Electric System - Rules of Procedure	Standard	Martin Boisvert	Hydro Quebec - TransEnergie			
2010-17	Definition of Bulk Electric System - Rules of Procedure	Standard	Ajay Garg	Hydro One Networks	416.345.5420	ajay.garg@HydroOne.com	

NPCC Members on NERC Drafting Teams

Updated: February 3, 2012							
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**	**Comments**
2006-02	Assess Transmission Future Needs & Develop Transmission Plans	Standard	Dana Walters	New York Independent System Operator	518-356-8582	dwalters@nyiso.com	
2006-02	Assess Transmission Future Needs & Develop Transmission Plans	Standard	Yury Tsimberg	Kinectrics	416-207-6000 X6106	Yury.Tsimberg@Kinectrics.com	Observer
~~2006-03~~	~~System Restoration & Blackstart~~	~~Standard~~	~~Steve Cooper~~	~~IESO~~	~~905-855-6159~~	~~steve.cooper@ieso.ca~~	
2006-03	System Restoration & Blackstart	Standard	David Mahlmann	NYISO	518-356-6101	dmahlmann@nyiso.com	
2006-03	System Restoration & Blackstart	Standard	Will Houston	National Grid	508-421-7690	will.houston@us.ngrid.com	
2006-04	Backup Facilities	Standard	John Procyk	Hydro One Networks	705-792-3210	john.procyk@hydroone.com	
2006-04	Backup Facilities	Standard	Mike Schiavone	National Grid	315-460-2472	michael.schiavone@us.ngrid.com	Vice-Chair
2006-06	Reliability Coordination	Standard	Earl Barber	National Grid	315-428-5532	earl.barber@us.ngrid.com	
2006-06	Reliability Coordination	Standard	Allan D. Miller	Independent Electricity System Operator	905-855-6158	al.miller@ieso.ca	
2006-07	ATC/TTC/AFC & CBM/TRM Revisions	Standard	Cheryl Mendrala	ISO-NE	413-535-4184	cmendrala@iso-ne.com	
2006-08	Transmission Loading Relief	Standard	Ben Li	Ben Li Associates, Inc.	647-388-1498	Ben@BenLi.ca	Chair
2007-01	Underfrequency Load Shedding	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com	Pending Regulatory Approval
2007-01	Underfrequency Load Shedding	Standard	Si Truc Phan	Hydro Quebec - TransEnergie	514-879-4100 X3610	Phan.Si_Truc@hydro.qc.ca	Pending Regulatory Approval
2007-02	Operating Personnel Communications Protocols	Standard	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com	
2007-03	Real-time Operations	Standard	Phil Lavallee	National Grid	508-389-2827	phil.lavallee@us.ngrid.com	
2007-04	Certifying System Operators	Standard	Rob MacDonald	Hydro One Networks	705-792-3095	Rob.Macdonald@HydroOne.com	
2007-05	Balancing Authority Controls	Standard	Guy Quintin	Hydro Quebec - TransEnergie	514-289-2211 X3150	Quintin.Guy@hydro.qc.ca	
2007-06	System Protection Coordination	Standard	Aaron Cooperberg	Hydro One Networks	416-345-5172	cooperberg@HydroOne.com	
2007-06	System Protection Coordination	Standard	David Cirka	National Grid	781-907-3240	david.cirka@us.ngrid.com	
2007-07	Vegetation Management	Standard	Dave Morrell	New York State Dept of Public Svc	518-486-7322	david_morrell@dps.state.ny.us	
2007-07	Vegetation Management	Standard	Orville Cocking	Con Edison			
2007-09	Generator Verification	Standard	Les Hajagos	Kestrel Power Engineering Ltd.	905-272-2191	les@kestrelpower.com	
2007-11	Disturbance Monitoring	Standard	Jeff Pond	National Grid	781-907-3222	jeff.pond@us.ngrid.com	
2007-12	Frequency Response	Standard	Harvey Happ	New York State Dept of Public Svc	518-486-2939	hhh@dps.state.ny.us	
2007-12	Frequency Response	Standard	Mike Potishnak	ISO-NE	413-535-4308	mpotishnak@iso-ne.com	
2007-14	Permanent Change to CI Table	Standard	No representation				
~~2007-17~~	~~Protection System Maintenance & Testing~~	~~Standard~~	~~John Ciufo~~	~~Hydro One Networks~~	~~416-345-5258~~	~~john.ciufo@hydroone.com~~	
~~2007-17~~	~~Protection System Maintenance & Testing~~	~~Standard~~	~~Leonard Swanson~~	~~National Grid~~	~~315-428-5250~~	~~leonard.swanson@us.ngrid.com~~	
2007-18	Reliability-based Control	Standard	Mike Potishnak	ISO-NE	413-535-4308	mpotishnak@iso-ne.com	
2007-23	Replace Levels of Noncompliance w/VSL	Standards	No representation				
2008-01	Reactive Planning and Control	SAR	Edwin E Thompson,	Con Edison	212-460-8199	thompsonedwin@coned.com	
2008-04	Facility Ratings for Order 705	Standard	No representation				
2008-06	Cyber Security for Order 706	Standard	John Lim	Con Edison	212-460-2712	limj@coned.com	Chair
2008-06	Cyber Security for Order 706	Standard	Frank Kim	Hydro One Networks	705-792-3033	Frank.Kim@HydroOne.com	
2008-06	Cyber Security for Order 706	Standard	Doug Johnson	Exelon-Commonwealth Edison	630-691-4593	douglas.johnson@comed.com	
2008-06	Cyber Security for Order 706	Standard	Robert Antonishen	Ontario Power Generation	905-262-2674	rob.antonishen@opg.com	
2008-06	Cyber Security for Order 706	Standard	Thomas Stevenson	Constellation Energy			
2008-08	Revise VSLs for Emergency Operations Standards	Standard	No Representation				
2008-12	Coordinate Interchange Modifications	Standard	Cheryl Mendrala	ISO-NE	413-535-4184	cmendrala@iso-ne.com	
2008-14	Cyber Security Violation Severity Levels	Standard	Mark Engels	Dominion	804-775-5263	mark.engels@dom.com	Pending Regulatory Approval
2008-14	Cyber Security Violation Severity Levels	Standard	David Dunn	IESO	905-855-6286	david.dunn@ieso.ca	Pending Regulatory Approval
2009-01	Disturbance and Sabotage Reporting	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com	Vice-Chair
2009-01	Disturbance and Sabotage Reporting	Standard	Michelle Draxton	Constellation Energy Group	410-474-2993	Michelle.I.draxton@constellation.com	

NPCC Members on NERC Drafting Teams

Updated: February 3, 2012							
2009-01	Disturbance and Sabotage Reporting	Standard	Drew Phillips	IESO	905-855-4114	drew.phillips@ieso.ca	
2009-01	Disturbance and Sabotage Reporting	Standard	Thomas J Curran	Con Edison	347-672-4621	currant@coned.com	
2009-02	Real-time Best Tools	SAR	Scott Vidler	Hydro One Networks	705-627-1436	scott.vidler@hydroone.com	
2009-07	Reliability of Protection Systems	SAR	Xiaodong Sun	Ontario Power Generation	289-257-0405	xiaodong.sun@opg.com	
2009-07	Reliability of Protection Systems	SAR	Dean V. Sorensen	National Grid	508-389-2301	Dean.Sorensen@us.ngrid.com	
2009-07	Reliability of Protection Systems	SAR	Stanley J. Lewis	Con Edison	212-780-2845	lewiss@coned.com	
2009-05	Resource Adequacy Assessments	Standard	Curt Dahl	National Grid	516-545-3662	cdahl@keyspanenergy.com	
2009-05	Resource Adequacy Assessments	Standard	Greg Drake	NYISO	518-356-6038	gdrake@nyiso.com	
2009-05	Resource Adequacy Assessments	Standard	Phil Fedora	NPCC	212-840-4909	pfedora@npcc.org	Vice-Chair
2010-05	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One	647-328-7068	paul.difilippo@hydroone.com	
2010-07	Generator Requirements at the Transmission Interface	SAR	Benjamin Church	FPL Group - NextEra Energy	561-304-5463	benjamin.church@fpl.com	
2010-10	FAC Order 729	Standard	No representation				
2010-17	Proposed Definition of Bulk Electric System	Standard	Jennifer Dering	NYPA		Jennfer.Dering@nypa.gov	
			Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com	
			Phil Fedora	NPCC	212-840-4909	pfedora@npcc.org	
			Ajay Garg	Hydro One Networks	416.345.5420	ajay.garg@HydroOne.com	
IRO-004	Require Timely Submission of Data	SAR	No representation				
NUC-001-1	Nuclear Plant Interface Coordination for FERC Order 716	SAR	Michael Schiavone	National Grid	315-460-2472	Michael.Schiavone@us.ngrid.com	
RRSWG	Regional Reliability Standards Working Group	N/A	Guy Zito	NPCC	212-840-1070	gzito@npcc.org	
FMWG	Functional Model Working Group	N/A	Mike Yealland	IESO			
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Standard Drafting Team Rosters

June 2012

RELIABILITY | ACCOUNTABILITY






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Standard Drafting Team Rosters

Assess Transmission Future Needs
Standard Drafting Team

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Balancing Authority Reliability-based Control, Phase 1: Reserves Standard Drafting Team

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Cyber Security for Order 706
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Definition of Bulk Electric System
Standard Drafting Team

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Standard Drafting Team

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Interpretation of COM-02-2
Standard Drafting Team

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Operating Personnel Communications Protocols Standard Drafting Team

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Real-Time Operations
Standard Drafting Team
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Revised: 7/16/2012

Tab Name	Last Revised	Summary of Changes
NERC RS Exec Tracking Summary	7/16/2012	For updates see: Project 2006-06 — Reliability Coordination Project 2010-07 — Generator Requirements at the Transmission Interface Project 2010-07 — Generator Requirements at the Transmission Interface Project 2007-17 — Protection System Maintenance & Testing_RE-INITIATED Project 2010-INT-01 Interpretation of TOP-006-2 R1.2 and R3 for FMPP Project 2011-INT-02 — Interpretation of VAR-002 for Constellation Project 2012-08.1 — Phase 1 of Glossary Updates: Statutory Definitions Project 2010-14.1 — Phase 1 of Balancing Authority Reliability-based Control: Reserves Project 2012-INT-02 — Interpretation of TPL-003-0a and TPL-004-0 for SPCS Project 2012-INT-05 — Interpretation of CIP-002-3 for OGE
NERC CANs	7/16/2012	For updates see: CAN-0019, CIP-007 R3.2 Implementation of Software Security Patches or Upgrades CAN-0023, CIP-005 R3, CIP-006 R6 Logging System Failures CAN-0033, PRC-023-1 Transmission Relay Loadability Criteria Selection CAN-0034, EOP-002 R1, IRO-001 R2 and TOP-001 R1 Use of Authority Letters CAN-0038, PER-002 R4 Training Hours CAN-0044, TOP-001 R1, R2 and R5 Operating Emergencies and Emergency Conditions
NPCC RRS Tracking Summary	7/16/2012	PRC-006-NPCC-01, Automatic Underfrequency Load Shedding Program - 5/4/12 FERC petitioned for approval
NPCC Doc Tracking Summary	7/16/2012	B-01: Draft Revised NPCC Guide for the Application of Autorelosing to the Bulk Power System - Posted to Open Process A-07 (retired), Revise Critical Component Definition (Glossary of Terms) - retirement date corrected.
NPCC Directory Tracking Summary	7/16/2012	Directory #5, Reserves - Open process posting for comment ended 6/25/12

NERC Reliability Standards Executive Tracking Summary

Revised: 7/16/2012

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status	
1	Project 2006-02 — Assess Transmission and Future Needs	High	TPL-001-2	Yes 3rd (Thru 3/16/07)	Yes 5th (Formal Thru 5/31/11)	Yes (Recirculation Thru 7/22/11)	Yes (7/22/11)	Yes (8/4/11)	Yes (10/19/11)			Under Development	
2	Project 2007-01 — Underfrequency Load Shedding	No	EOP-003-1 and PRC-006-1	Yes 3rd (Thru 3/29/07)	Yes 3rd (Thru 7/16/10)	Yes 6th (Recirc Thru 10/28/10)	Yes (10/28/10)	Yes (11/4/10)	Yes (3/31/11)		NOPR Issued 10/20/11. NOPR proposes to approve Reliability Standards PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans) submitted by NERC. Comments are due 60 days after publication in the Federal Register.	Pending Regulatory Approval	
3	Project 2007-07 — Vegetation Management	Normal	FAC-003-2	Yes 3rd (Thru 7/17/07)	Yes 5th (Thru 2/28/11)	Yes 6th (Recirculation Thru 10/13/11)	Yes (10/13/11)	Yes (11/3/11)	Yes (12/21/11)			Under Development	
4	Project 2008-14 — Cyber Security Violation Severity Levels	No	CIP family of standards	Yes 2nd (Thru 04/20/09)	Yes 1st (Thru 04/20/09)	Yes (Recirc Thru 7/16/09)	Yes (7/16/09)	Date?	Date?			Pending Regulatory Approval	
5	Project 2010-11 — TPL Table 1 Order	No	TPL-002 Footnote b	Yes 1st (Thru 5/26/10)	Yes 3rd (Thru 1/5/11)	Yes 3rd (Recirc Thru 2/5/11)	Yes (2/5/11)	Yes (2/17/11)	Yes (3/31/11)		- FERC NOPR issued 10/20/11. This Notice of Proposed Rulemaking (NOPR) proposes to remand to NERC its proposed modification to Reliability Standard TPL-002, Table 1, footnote 'b' because it does not adequately clarify or define the circumstances in which an entity can plan to shed firm load for a single contingency. Comments are due 60 days after publication in the Federal Register. - Ref: FERC 3/18/10 Order Setting Deadline for Compliance [Docket RM06-16-009] -- NERC to clarify Std TPL 002-0	Pending Regulatory Approval	
6	Project 2010-17 — Definition of Bulk Electric System	High	NERC Glossary Of Terms	Yes 1st (Thru 1/21/11)	- Yes 3rd (Definition Thru 10/10/11) - Yes 2nd (ROP & Tech Principles Thru 10/10/11)	Yes (Recirc Thru 11/21/11)	Yes 11/21/11	Yes (1/18/12)	Yes (1/25/12)				
7	Urgent Action SAR for Revision	No	BAL-004-1	Yes 2nd (Thru 10/18/07)	Yes 2nd (Thru 10/18/07)	Yes 1st (Recirc Thru 12/4/07)	Yes (12/4/07)	Yes (3/26/08)	Yes (3/11/09)		- NERC Motion to Further Defer Action Issued 8/11/11 - NERC Motion to Defer Action Issued 8/20/10 - FERC NOPR [Docket RM09-13-000 (March 18, 2010)] - Commission proposes to remand BAL-004-1	Pending Regulatory Approval	
8	Project 2006-06 — Reliability Coordination	Normal	IRO-002-3, IRO-005-4, IRO-014-2 COM-001-2, COM-002-3, IRO-001-3 and IRO-014-2	Yes 3rd "Supp" (Thru 9/3/10)	Yes (Thru 7/6/12) COM-001-2 COM-002-3 IRO-001-3	Yes (Successive Thru 7/6/12) COM-001-2 Yes (Recirculation Thru 7/6/12) COM-002-3 IRO-001-3	IRO-002-3 IRO-005-4 IRO-014-2 Yes (7/25/11)	IRO-002-3 IRO-005-4 IRO-014-2 Yes (8/4/11)				Under Development	x
9	Project 2007-03 — Real-time Operations	High	TOP-001-2, TOP-002-3, TOP-003-2 and PER-001-2	Yes 2nd (Thru 9/07/07)	Yes (Thru 4/20/12)	Yes (Successive Thru 4/20/12)	Update 5/6/12	Update 5/9/12				Under Development	
10	Project 2008-10 — Interpretation of CIP-006-1 R1.1 by Progress Energy	No	CIP-006, R1.1	x	Yes (thru 11/21/11)	Yes (Recirculation Thru 12/19/11)	Yes 12/19/11	Yes (2/9/12)				Under Development	
11	Project 2009-22 — Interpretation of COM-002-2 R2 by the IRC	High - Interp.	COM-002-2	x	2nd (45 day Formal thru 11/17/11)	Yes (Recirculation Thru 12/23/11)	Yes (12/23/11)	Yes (2/9/12)			Project 2009-22 (COM-002-2),which applies to real-time emergency communications, was approved by NERC BOT with an amendment that calls for the prioritization of a revised standard and a best practices memorandum shared with industry.	Under Development	
12	Project 2010-07 — Generator Requirements at the Transmission Interface	High	FAC-001-1, ~~FAC-003-3, FAC-003-X~~	Yes 1st (Thru 3/15/10)	Yes 3rd (45 Day Formal Thru 11/18/11)	Yes (Recirculation Thru 12/23/11)	Yes (12/23/11)	Yes (2/9/12)			FAC-001-1 NERC BOT Approved	Under Development	
13	Project 2010-07 — Generator Requirements at the Transmission Interface	High	PRC-004-2	Yes 1st (Thru 3/15/10)	Yes 1st (45 Day Formal Thru 11/18/11)	Yes (Recirculation Thru 12/23/11)	Yes (12/23/11)	Yes (2/9/12)			PRC-004-2.1a NERC BOT Approved	Under Development	
14	Project 2010-07 — Generator Requirements at the Transmission Interface	High	FAC-003-3, FAC-003-X	Yes 1st (Thru 3/15/10)	Yes (30 Day Formal Thru 4/9/12)	Yes (Recirculation Thru 5/3/12)	Yes (5/3/12)	Yes (5/9/12)			Exelon Appeal upheld - 12/23/11 Recirc Ballot overturned	Under Development	x
15	Project 2010-07 — Generator Requirements at the Transmission Interface	High	PRC-005-1.1a	x	Yes (45 Day Formal Thru 4/16/12)	Yes (Recirculation Thru 5/3/12)	Yes (5/3/12)	Yes (5/9/12)					x
16	Project 2010-09 — Cyber Security Order 706B — Nuclear Plant Implementation Plan	No	Various CIP Standards	Yes 1st (Thru 3/15/10)	Yes 1st (Thru 3/15/10)	Yes (Recirc Thru 7/2/10)	Yes (7/2/10)	Yes (8/5/10)				Pending Regulatory Filing	
17	Project 2011-INT-01 Interpretation of MOD-028 for FPL	No	MOD-028	Yes 1st (Thru 11/16/11)	Yes 1st (Thru 11/16/11)	Yes (Recirculation Thru 12/22/11)	Yes (12/22/11)	Yes (2/9/12)				Under Development	
18	Project 2009-20 — Interpretation of BAL-003-0 R2 and R5 by Energy Mark, Inc.	No	BAL-003-0.1b	x	x	Yes (Recirc Thru 2/26/10)	Yes (2/26/10)					Under Development	
19	Project 2007-02 — Operating Personnel Communications Protocols	High	COM-003-1 and COM-002-2	Yes 2nd (Thru 5/2/07)	Update 6/20/12	Update IB 6/20/12						Under Development	
20	Project 2007-06 — System Protection Coordination	High	PRC-027-1 Update	Yes 1st (Thru 7/10/07)	Update 7/5/12	Update IB 7/5/12						Under Development	
21	Project 2007-09 — Generator Verification	High	MOD-026-1 and PRC-024-1* MOD-024-2** MOD-025-2, MOD-027-1, PRC-019-1***	Yes 1st (Thru 5/21/07)	*Yes (Thru 3/29/12) **Yes 1st (Thru 2/18/10) ***Yes (Thru 4/16/12)	*Yes (Successive Thru 3/29/12) ** *** Yes (Initial Thru 4/16/12)						Under Development	
22	Project 2007-12 — Frequency Response	High	BAL-003-1	Yes 3rd (Thru 3/09/07)	Yes 2nd (45 Day Formal Thru 12/8/11)	Yes 1st (Initial Thru 12/8/11) Failed						Under Development	
23	Project 2007-17 — Protection System Maintenance & Testing RE-INITIATED	High	PRC-005-2	Yes 1st (Thru 9/28/11)	Yes (Thru 6/27/12)	Yes (Successive Thru 6/27/12)						Under Development	x

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Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status	
24	Project 2008-06 — Cyber Security — Order 706 -- CIP Version 5 Standards	High	CIP-002-5 thru CIP-009-5, CIP-010-1 and CIP-011-1	x	Yes (Thru 5/21/12)	Yes (Successive Thru 5/21/12)						Under Development	
25	Project 2009-01 — Disturbance and Sabotage Reporting	High	EOP-004-2	Yes 1st (Thru 5/21/09)	Update 5/24/12	Update SB 5/24/12						Under Development	
26	Project 2009-24 — Interpretation of EOP-005-1 R7 by FMPA	No	EOP-005-1, R7	x	x	Yes 1st (Intitial Thru 1/15/10)					Balloting Deferred per Standards Committee	Under Development	
27	Project 2009-26 — Interpretation of CIP-004-1 by WECC	No	CIP-004-1, R2, R3 and R4	x	Yes (Thru 3/23/12)	Yes (Recirculation Thru 4/30/12)						Under Development	
28	Project 2010-INT-01 Interpretation of TOP-006-2 R1.2 and R3 for FMPP	No	TOP-006-3, R1.2 and R3	NA	Yes - Draft #1 (Thru 7/30/12)	Yes - Draft #1 (Initial Thru 7/30/12)					Requester has been contacted to see if CAN provides necessary clarication - awaiting response	On Hold	x
29	Project 2010-INT-05 CIP-002-1 Requirement R3 for Duke Energy	No	CIP-002-1, R3	x	Yes (Thru 3/23/12)	Yes (Recirculation Thru 4/30/12)						Under Development	
30	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	No	VAR-002-1.1b, R2	x	Yes (Thru 6/27/12)	Yes (Successive Thru 6/27/12)					"Rapid Revision"	Under Development	x
31	Project 2012-08.1 — Phase 1 of Glossary Updates: Statutory Definitions	No	NERC Glossary Of Terms	For Comment (Thru 8/2/12)	Yes (Thru 8/2/12)	Yes (Intitial Thru 8/2/12)							x
32	Project 2007-11 — Disturbance Monitoring	No	PRC-002-1 and PRC-018-1	Yes 1st (Thru 4/20/07)	Yes 1st (Thru 3/18/09)							Under Development	
33	Project 2008-12 — Coordinate Interchange Standards	No	INT-004-, INT-006-4, INT-009-2, INT-010-2 and INT-011-1	Yes 1st (Thru 7/31/08)	Yes 1st (Thru 12/11/09)							Under Development	
34	Project 2009-02 — Real-time Reliability Monitoring and Analysis Capabilities	No	"New"	Yes 2nd (Thru 2/18/10)	Yes 1st (Informal Thru 4/4/11)						Concept White Paper posted for informal comment period	Under Development	
35	Project 2010-05.1 — Protection Systems: Phase 1 (Misoperations)	High	PRC-004-3	Yes 1st (Informal Thru 7/11/11)	Yes 1st (30 Day Formal Thru 7/11/11)						".1" refers to Phase 1 of the Project		
36	Project 2010-14.1 — Phase 1 of Balancing Authority Reliability-based Control: Reserves	No	BAL-001-1, BAL-002-2, BAL-012-1, BAL-013-1	NA	Yes - Draft #1 Thru 7/3/12						As of July 28, 2010 this project has merges Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control into a single project	Under Development	x
37	Project 2010-16 — Definition of System Operator	No	NERC Glossary Of Terms	Yes 1st (Thru 12/3/10)	Yes 1st (Thru 12/3/10)							Under Development	
38	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	No	TPL-003 and TPL-004	NA	Yes - Draft #1 (Thru 7/19/12)								x
39	Project 2012-INT-05 – Interpretation of CIP-002-3 for OGE	No	CIP-002	NA	Yes - Draft #1 (Thru 7/27/12)								x
40	Project 2008-01 — Voltage and Reactive planning and control	No	VAR-001 and VAR-002	Yes 2nd (Thru 3/26/10)								Under Development	
41	Project 2008-02 — Undervoltage Load Shedding	No	PRC-010-0 and PRC-022-1	Yes 1st (Thru 02/19/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred	
42	Project 2009-03 — Emergency Operations	No	EOP-001, EOP-002, EOP-003 and IRO-001	Yes 1st (Thru 1/15/10)								Under Development	
43	Project 2009-05 — Resource Adequacy Assessments	No	"New"	Yes 2nd (Thru 3/30/06)								Under Development	
44	Project 2009-07 — Reliability of Protection Systems	No	"New"	Yes 1st (Thru 2/18/09)							Pending prioritization - may be postponed	Under Development	
45	Project 2010-08 — Functional Model Glossary Revisions	No		Yes 1st (Thru 2/22/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred	
46	Project 2010-17 — Definition of Bulk Electric System - Phase 2	High	NERC Glossary Of Terms	For Comment (Thru 2/3/12)								Under Development	
47	Project 2009-04 — Phasor Measurement Units	No										Project has not started	
48	Project 2010-01 — Support Personnel Training	No									2/15/12 - FERC has granted NERC a two-year extension of time to and including September 30, 2014 to complete the Project pursuant to the Commission's Order No. 742. [Docket No. RM09-25-000]	Project has not started	
49	Project 2010-02 — Connecting New Facilities to the Grid	No										Project has not started	
50	Project 2010-03 — Modeling Data	No										Project has not started	
51	Project 2010-04 — Demand Data	No										Project has not started	
52	Project 2010-06 — Results-based Reliability Standards	No	Results-based Reliability Standards Transistion Plan								Transistion Plan posted 7/26/10		
53	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	No									- ".2" refers to Phase 2 of the Project - 2/15/12 - FERC has granted NERC a one-year extension of time to and including September 30, 2013 to complete the Project pursuant to the Commission's Order No. 733. [Docket No. RM08-13-001]		
54	Project 2010-INT-02 Interpretation of TOP-003-1 R2 for FMPP	No	TOP-003-1, R2								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold	
55	Project 2010-INT-03 Interpretation of TOP-002-2a R2, R8, and R19 for FMPP	No	TOP-002-2a, R2, R8 and R19								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold	
56	Project 2012-01 Equipment Monitoring and Diagnostic Devices	No	FUTURE										
57	Project 2012-02 Physical Protection	No	FUTURE										
58	Pre-2006 — Operate Within Interconnection Reliability Operating Limits	No	IRO-008-1, IRO-009-1 and IRO-010-1a	Yes 2nd (Thru 9/23/02)	Yes 9th (Thru 4/25/08)	Yes 1st (Recirc Thru 8/21/08)	Yes (8/21/08)	Yes (10/17/08)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 - Rule published in Federal Register on March 23, 2011	Completed	
59	Project 2006-01 — System Personnel Training	No	PER-004-2 and PER-005-1	Yes 2nd (Thru 3/20/06)	Yes 4th (Thru 7/17/08)	Yes 5th (Recirc Thru 12/22/08)	Yes (12/22/08)	Yes (04/01/09)	Yes (9/30/09)	Yes (11/18/10)		Completed	
60	Project 2006-03 — System Restoration and Blackstart	No	EOP-001-1, EOP-005-2 and EOP-006-2	Yes 2nd (Thru 3/09/07)	Yes 4 th (Thru 11/18/08)	Yes 5th (Recirc Thru 5/18/09)	Yes (5/18/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 (Effective Std EOP-001-2) - Rule published in Federal Register on March 23, 2011	Completed	
61	Project 2006-04 — Backup Facilities	No	EOP-008-1	Yes 2nd (Thru 3/16/07)	Yes 5th (Thru 3/8/10)	Yes 7th (Recirc Thru 7/26/10)	Yes (7/26/10)	Yes (8/5/010)	Yes (2/11/11)	Yes (4/21/11)	Posted in Federal Register on 4/28/11	Completed	

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Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
62	Project 2006-08 — Transmission Loading Relief	No	IRO-006-5 and IRO-006-East-1	Yes (For DT Nomination 1/12/07)	Yes 4th (Thru 11/30/09)	Yes 6th (Recirc Thru 8/30/10)	Yes (8/30/10)	Yes (11/4/10)	Yes (1/13/11)	Yes (4/21/11)		Completed
63	Project 2007-04 — Certifying System Operators	Normal	PER-003-1	Yes 2nd (Thru 1/31/08)	Yes 1st (Thru 11/20/09)	Yes 3rd (Recirc Thru 12/13/10)	Yes (12/31/10)	Yes (2/17/11)	Yes (4/29/11)	Yes (9/15/11)		Completed
64	Project 2007-05 — Balancing Authority Controls	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
65	Project 2007-17 — Protection System Maintenance & Testing	High	PRC-005-2	Yes 1st (Thru 7/10/07)	Yes 4th (30 day formal Thru 5/12/11)	Yes 8th (Recirculation Thru 6/30/11)	Failed to reach ballot pool aproval	NA	NA	NA	After PRC-005-2 failed to reach ballot pool approval in the recirculation ballot that ended on 6/30/11, the drafting team revised the standard. The Standards Committee authorized re-initiating the project with a posting of the SAR and revised standard for a 45-day comment period, with an initial ballot of the standard conducted during the last 10 days of the comment period.	Re-initiated
66	Project 2007-18 — Reliability-based Control	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
67	Project 2007-23 — Violation Severity Levels	No	Six sets of VSLs for various standards	Yes 2nd "Supp" (Thru 9/16/10)	Yes 6th (Thru 2/18/11)	Yes (Non-Binding Poll Thru 2/18/11	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
68	Project 2007-24 - Interpretation of TPL-002 and TPL-003	No	TPL-002-0a and TPL-003-0a	x	x	Yes 2nd (Thru 7/7/08)	Yes (7/7/08)	Yes (7/30/08)	Yes (10/24/08)	Yes (4/23/10)		Completed
69	Project 2007-27 — Interpretation of CIP-006 R1.1 by SCE&G	No	CIP-006, R1.1	x	x	Yes (Recirc Thru 12/4/07)	Yes (12/4/07)	Yes (2/12/08)	Yes (12/22/09)	Yes (5/19/11)		Completed
70	Project 2008-06 — Cyber Security — Order 706 (CIP-002-4)	High	CIP-002-4 thru CIP-009-4	x	Yes 1st (Thru 11/3/10)	Yes Recirc Thru 12/30/10) - passed	Yes (12/30/10)	Yes (1/24/11)	Yes (2/10/11)	Yes (4/19/12)		Completed
71	Project 2008-06 — Cyber Security — Order 706 (VRFs and VSLs)	No	CIP VRFs and VSLs	x	Yes 1st (Thru 4/20/09)	Yes (Recirc Thru 11/12/09)	Yes (11/12/09)	Yes (12/16/09)	Yes (12/18/09)	Yes (1/20/11)		Completed
72	Project 2008-07 — Interpretation of EOP-002-2 R6.3 and R7.1 by Brookfield Power	No	EOP-002-2, R6.3 and R7.1	x	x	Yes (Recirc Thru 8/31/09)	Yes (8/31/09)	No (Remanded 2/16/10)	NA	NA	2/16/10 NERC BOT: (1) Remands the proposed interpretation of EOP-002-2, Requirements R6.3 and R7.1, to the Standards Committee because the proposed interpretation adds requirements not in the standard, thereby exceeding the permissible scope of an interpretation, and (2) Directs the Standards Committee to initiate action to revise EOP-002-2 as appropriate	NA
73	Project 2008-08 — EOP VSL Revisions	No	EOP family of standards	Yes 1st (Thru 5/19/08)	Yes 2nd (Thru 12/3/09)	Yes (Non-Binding Poll Thru 2/18/11	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
74	Project 2008-09 — Interpretation of EOP-001-0 R1 by Regional Entity Compliance Managers	No	EOP-001-0, R1	x	x	Yes 4th (Recirc Thru 10/14/10)	Yes (10/14/10)	Yes (11/4/10)	Yes (9/9/11)	Yes (12/15/11)	The standard will now be referred to as EOP-001-2b	Completed
75	Project 2008-11 — Interpretation of VAR-002a by ICF Consulting	No	VAR-002-1.1b	x	x	Yes (Recirc Thru 1/6/09)	Yes (1/6/09)	Yes (2/10/09)	Yes (3/5/09)	Yes (9/16/10)		Completed
76	Project 2008-15 — Interpretation of CIP-006-1a By US Army Corps of Engineers	No	CIP-006-1a, R4	x	x	Yes (Recirc Thru 2/16/09)	Yes (2/16/09)	Yes (8/5/09)	Yes (12/22/09)	Yes (5/19/11)		Completed
77	Project 2008-18 — Interpretation of TOP-005-1 and IRO-005-1 by Manitoba Hydro	No	TOP-005-1 , R3 and IRO-005-1, R12	x	x	Yes (Recirc Thru 4/27/09)	Yes (4/27/09)	Yes (11/5/09)	Yes (11/24/09)	Yes (4/21/11)	Posted in Federal Register on 4/26/11	Completed
78	Project 2009-06 — Facility Ratings	Normal	FAC-008-3 (was FAC-008-2)	Yes 2nd (Thru 9/9/09)	Yes 3rd (Formal Thru 5/2/11)	Yes 6th (Recirculation Thru 5/23/11)	Yes (5/23/11)	Yes (5/24/11)	Yes (6/15/11)	Yes (11/17/11)	FAC-008-3 is effective the first day of the first calendar quarter that is twelve months after issuance of the FERC Order. FAC-008-3 combines FAC-008-1 and FAC-009-1 into a single standard.	Completed
79	Project 2009-08 — Nuclear Plant Interface Coordination	No	NUC-001-2	Yes 1st (Thru 3/18/09)	Yes 1st (Thru 3/18/09)	Yes (Recirc Thru 7/20/09)	Yes (7/20/09)	Yes (8/5/09)	Date?	Yes (1/21/10)		Completed
80	Project 2009-09 — Interpretation of CIP-001-1 by Covanta	No	CIP-001-1a	x	x	Yes (Recirc Thru 10/9/09)	Yes (10/09/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
81	Project 2009-10 — Interpretation of PRC-005-1 R1 by Compliance Monitoring Processes Working Group (CMPWG)	No	PRC-005-1, R1	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (2/3/12)	Posted in Federal Register 2/13/12 - Effective 3/14/12	Completed
82	Project 2009-11 — Interpretation of IRO-010-1 R1.2 and R3 by WECC Reliability Coordination Subcommittee	No	IRO-010-1 R1.2 and R3 --> IRO-010-1a	x	x	Yes (Recirc Thru 6/5/09)	Yes (6/5/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	NOPR issued 11/18/10, Comments were due 1/24/11	Completed
83	Project 2009-12 — Interpretation of CIP-005-1 by PacifiCorp	No	CIP-005-3a	x	x	Yes (Recirc Thru 10/26/09)	Yes (10/26/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
84	Project 2009-13 — interpretation of CIP-006-1 by PacifiCorp	No	CIP-006-2c	x	x	Yes (Recirc Thru 12/23/09)	Yes (12/23/09)	Yes (2/16/10)	Yes (4/20/10)	Yes (7/15/10)		Completed
85	Project 2009-14 — Interpretation of TPL-002-0 R1.3.10 by PacifiCorp	No	TPL-002-0, R1.3.10	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (9/15/11)	Posted in Federal Register on 9/22/11 - Effective Date: This rule will become effective October 24, 2011	Completed
86	Project 2009-15 — Interpretation of MOD-001-1 R2 and R8 and MOD-029-1 R5 and R6 by NYISO	No	MOD-001-1, R2 and R8 and MOD-029-1 R5 and R6	x	x	Yes (Recirc Thru 7/17/09)	Yes (7/17/09)	Yes (11/5/09)	Yes (12/2/09)	Yes (9/16/10)		Completed
87	Project 2009-16 — Interpretation - CIP-007-1, R2 — Systems Security Management	No	CIP-007-2a	x	x	Yes (Intitial Thru 9/21/09)	Yes (9/21/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (3/18/10)		Completed
88	Project 2009-17 — Interpretation of PRC-004-1 and PRC-005-1 R2 by Y-W Electric and Tri-State G & T	No	PRC-004-1 and PRC-005-1	x	x	Yes 3rd (Recirc Thru 12/3/10)	Yes (12/3/10)	Yes (2/17/11)	Yes (4/15/11)	Yes (9/26/11)		Completed
89	Project 2009-18 — Withdraw Three Midwest ISO Waivers	No	BAL-006-2 and INT-003-3	x	x	Yes (Intitial Thru 9/8/09)	Yes (9/8/09)	Yes (11/5/09)	Yes (11/20/09)	Yes (1/6/11)		Completed
90	Project 2009-19 — Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group	No	BAL-002-0 R4 and R5	x	x	Yes (Intitial Thru 2/26/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
91	Project 2009-21 — Cyber Security Ninety-day Response — CIP Family of Standards	No	CIP-002 through CIP-009, V3	Yes 1st (Thru 11/12/09)	Yes 1st (Thru 11/12/09)	Yes (Recirc Thru 12/14/09)	Yes (12/14/09)	Yes	Yes (1/19/10)	Yes (3/18/10)		Completed
92	Project 2009-23 — Interpretation of CIP-004-2 R3 by Army Corps of Engineers	No	CIP-004-2	x	x	Yes 2nd (Intitial Thru 4/8/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11

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93	Project 2009-25 — Interpretation of BAL-001-01 and BAL-002-0 by BPA	No	BAL-001-0.1a and BAL-002-0	x	x	Yes 1st (Intitial Thru 1/15/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
94	Project 2009-27 — Interpretation of TOP-002-2a R10 by FMPP	No	TOP-002-2a, R10	x	x	Yes (Recirc Thru 10/16/10)	Yes (10/16/10)	Yes (11/4/10)	Yes (4/15/11)	Yes (10/20/11)		Completed
95	Project 2009-28 — Interpretation of EOP-001-1 and EOP-001-2 R2.2 by FMPP	No	EOP-001-1 and EOP-001-2	x	x	Yes (Recirc Thru 10/15/10)	Yes (10/15/10)	Yes (11/4/10)	Yes (9/9/11)	Yes (12/15/11)	The standard will now be referred to as EOP-001-2b	Completed
96	Project 2009-29 — Interpretation of TOP-002-2a R6 by FMPP	No	TOP-002-2a, R6	x	x	Yes 1st (Intitial Thru 2/22/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
97	Project 2009-30 — Interpretation of PRC-001-1 R1 by WPSC	No	PRC-001-1	x	x	Yes 1st (Intitial Thru 2/26/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
98	Project 2009-31 — Interpretation of TOP-001-1 R8 by FMPP	No	TOP-001-1, R8	x	x	Yes 1st (Intitial Thru 3/16/10)	Yes (3/16/10)	Yes (5/12/10)	Yes (7/16/10)	Yes (9/15/11)	Posted in Federal Register on 9/20/11 - Effective Date: This rule will become effective November 21, 2011	Completed
99	Project 2009-32 — Interpretation of EOP-003-1 R3 and R5 by FMPP	No	EOP-003-1, R3 and R5	x	x	Yes 2nd (Re-ballot Thru 3/31/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
100	Project 2010-10 — FAC Order 729	No	FAC-013-2	Yes 1st (Thru 4/29/10)	Yes 3rd (Thru 1/8/11)	Yes 3rd (Recirc Thru 1/23/11)	Yes (1/23/11)	Yes (1/24/11)	Yes (1/28/11)	Yes (11/17/11)	FAC-013-2 is effective the first day of the calendar quarter twelve months after Commission approval.	Completed
101	Project 2010-12 — Order 693 Directives	No	BAL-002-1, EOP-002-3, FAC-002-1, MOD-021-1, PRC-004-2 and VAR-001-2	Yes 1st (Thru 7/13/10)	Yes 1st (Thru 7/13/10)	Yes 2nd (Recirc Thru 7/31/10)	Yes (7/31/10)	Yes (8/5/10)	Yes (9/9/10)	Yes (1/10/11)		Completed
102	Project 2010-13 — Relay Loadability Order	Normal	PRC-023-2	Yes 1st (Thru 9/19/10)	Yes 3rd (Thru 12/16/10)	Yes 3rd (Recirculation Thru 3/6/11)	Yes (3/6/11)	Yes (3/10/11)	Yes (3/18/11)	Yes (3/15/12)	Posted in Federal Register 3/21/12 - Effective Date 5/7/12	Completed
103	Project 2010-15 — Urgent Action Revisions to CIP-005-3	Urgent	CIP-005-4	Yes 1st (Thru 9/27/10)	Yes 3rd (Thru 4/28/11)	Yes 3rd (Thru 4/28/11)	NA	NA	NA	NA	Absorbed into Project 2008-06; Project 2010-15 curtailed	Project Curtailed
104	Project 2010-INT-04 Interpretation of EOP-001-1 R2.4 for FMPP	No	EOP-001-1, R2.4	x	x	x	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11

Acronyms:
SAR- Standards Authorization Request
RS- Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOT- NERC Board of Trustee

NERC Compliance Application Notice Executive Tracking Summary

Revised: **7/16/2012**

Further details regarding the individual documents may be found at: http://www.nerc.com/page.php?cid=3%7C22%7C354

CAN#	Project No. / Title	Associated Standard or Issue	Requirement	Advance Notice?	Posted for Comment?	Comments Posted?	CAN Issued?	Comments
~~CAN-0001~~	~~INT-004-2 R1: Compliance Application Notice~~	~~INT-004-2~~	~~1~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0002~~	~~TOP-003-0 R1.3: Compliance Application Notice~~	~~TOP-003-0~~	~~1.3~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0003~~	~~IRO-006-4.1 R2: Compliance Application Notice~~	~~IRO-006-4.1~~	~~2~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0004~~	~~IRO-004-1 R3: Compliance Application Notice~~	~~IRO-004-1~~	~~3~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
CAN-0005	CIP-002-3 R3: Compliance Application Notice (Revised)	CIP-002-3	3	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0006	EOP-005 R7: Verification of Restoration Procedure (Revised)	EOP-005-1	7	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (11/11/11)	Yes (11/11/11)	Revised CAN posted 11/11/11
CAN-0007	CIP-004-2 R4.2 and CIP-004-3 R4.2: Compliance Application Notice	CIP-004-2, CIP-004-3	4.2, 4.2	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0008	PRC-005 R2: Basis for First Maintenance and Testing Date (Revised)	PRC-005-1	R2 Pre-June 18 evidence	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (11/16/11)	Yes (4/10/12 - Revised)	Revised CAN posted 4/10/12
CAN-0009	FAC-008 and FAC-009: Facility Ratings and Design Specifications (Revised)	FAC-008 & FAC-009	R1, R1, R2	x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (11/11/11)	Revised CAN issued 11/11/11
CAN-0010	Implementation of Annual in Reliability Standards Requirements (Revised)	Definition of "Annual"		x	x	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0011	PRC-005 R2: Interval Start Date for New Equipment (Revised)	PRC-005-1	R2 - new equipment	x	x	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0012	Completion of Periodic Activity Requirements During Implementation Plan (Revised)			x	Yes 1/21/11 (Thru 2/4/11)	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0013	PRC-023 R1 and R2: Effective Dates for Switch-On-To-Fault Schemes (Revised)	PRC-023		x	Yes 1/21/11 (Thru 2/4/11)	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0015	Unavailability of NERC Software Tools			x	Yes 2/4/11 (Thru 2/18/11)	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
~~CAN-0016~~	~~CIP-001 R1: Sabotage Reporting Procedure (Revised)~~	~~CIP-001~~		~~x~~	~~Yes 8/15/11 (Thru 9/6/11) - Revision~~	~~Yes (10/14/11)~~	~~Yes (10/14/11)~~	REMANDED 2/8/12 and then WITHDRAWN 2/16/12
CAN-0017	CIP-007 R5: Technical and Procedural System Access and Password Controls	CIP-007	R5	x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (11/11/11)	Revised CAN posted 11/11/11
CAN-0018	FAC-008 R1.2.1: Terminal Equipment (Revised)	FAC-008		x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (11/11/11)	Yes (11/11/11)	Revised CAN posted 11/11/11
CAN-0019	CIP-007 R3.2 Implementation of Software Security Patches or Upgrades	CIP-007	R3.2	x	Yes 4/10/12 (Thru 6/4/12)	Yes (4/26/12)		x
CAN-0020	Draft CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002	TPL-002, TPL-003, TPL-004		x	Yes 10/19/11 (Thru 11/9/11)	Yes (12/15/11)	Yes (12/15/11)	
CAN-0021	Draft CAN-0021 COM-002 Definition of Directive and Use of Three-Part Communications	COM-002		Yes (5/9/11)				
CAN-0022	CAN-0022 VAR-002-1.1b R1 and R3	VAR-002		x	Yes 4/19/11 (Thru 5/11/11)	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0023	CIP-005 R3, CIP-006 R6 Logging System Failures	CIP-005	R3	x	Yes 4/10/12 (Thru 6/4/12)	Yes (4/26/12)		x
CAN-0024	Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CIP-002 through CIP-009		x	Yes 5/20/11 (Thru 6/10/11)	Yes (11/30/11)	Yes (12/15/11)	
CAN-0026	CAN-0026 TOP-006-X R3 Protection Relays	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0027	Draft CAN-0027 TOP-003 R1.1 and R2 Generator	TOP-003		x	Yes (Thru 12/14/11)	Yes (12/21/11)	Yes (12/21/11)	
CAN-0028	TOP-006 R1.2: Reporting Responsibilities (Revised)	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0029	Protection System Misoperations, PRC-004-1 R1, R2, R3	PRC-004	R1, R2, R3	x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (12/9/11)	
CAN-0030	Draft CAN-0030 Attestations	Attestations		x	Yes 10/19/11 (Thru 11/9/11)	Yes (11/22/11)	Yes (12/9/11)	
CAN-0031	Acceptable Opening Dimensions, CIP-005 and CIP-006	CIP-005 and CIP-006		x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/16/11)	Yes (12/9/11)	
CAN-0033	PRC-023-1 Transmission Relay Loadability Criteria Selection	PRC-023		x	Yes 6/8/12 (thru 7/27/12			x
CAN-0034	EOP-002 R1, IRO-001 R2 and TOP-001 R1 Use of Authority Letters	EOP-002 IRO-001 TOP-001	R1 R2 R1	x	Yes 4/10/12 (Thru 5/7/12)	Yes (5/8/12)		x
CAN-0038	PER-002 R4 Training Hours	PER-002	R4	x	Yes 4/10/12 (Thru 5/7/12)	Yes (5/8/12)		x
CAN-0039	Filing DOE Form OE-417 Event Reports, EOP-004-1	EOP-004		x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (12/9/11)	
CAN-0040	BAL- 003 Frequency Response Calculation	BAL-003		x	Yes 11/2/11 (Thru 11/23/11)	Yes (12/9/11)	Yes (12/30/11)	
CAN-0043	PRC-005 Protection System Maintenance and Testing Evidence	PRC-005		x	Yes 11/2/11 (Thru 11/23/11)	Yes (12/9/11)	Yes (2/16/12 - Revised)	Revised CAN posted 2/16/12

NERC Compliance Application Notice Executive Tracking Summary

Revised: **7/16/2012**

Further details regarding the individual documents may be found at: http://www.nerc.com/page.php?cid=3%7C22%7C354

CAN#	Project No. / Title	Associated Standard or Issue	Requirement	Advance Notice?	Posted for Comment?	Comments Posted?	CAN Issued?	Comments
CAN-0044	TOP-001 R1, R2 and R5 Operating Emergencies and Emergency Conditions	TOP-001	R1, R2, R5	x	Yes 6/8/12 (thru 7/27/12			

Acronyms:
CAN - Compliance Application Notice

NPCC Regional Reliability Standards Executive Tracking Summary

Revised: 7/16/2012

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/UnderDev.aspx

Line No.	Regional Standard ID	Regional Reliability Standard Title	RSAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NPCC BOD Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
1	BPS-501-NPCC-01	Classification of Bulk Power System Elements (Withdrawn by RSC 8/07/09)	Yes (Thru 2/4/08)	NA	NA	NA	NA	NA	NA	NA	Withdrawn by RSC 8/07/09	Withdrawn
2	PRC-002-NPCC-01	Disturbance Monitoring	Yes (Thru 9/10/08)	Yes (Thru 10/24/09)	Yes (Thru 1/6/10)	Yes (1/6/10)	Yes (1/9/10)	Yes (11/4/10)	Yes (5/31/11)	Yes (10/20/11)	10/24/11 - Approved Standard posted publicly	Completed
3	PRC-006-NPCC-01	Automatic Underfrequency Load Shedding Program	Yes (Thru 8/25/08)	Yes (Thru 11/2/11)	Yes (Pre-ballot Thru 11/2/11)	Yes (11/18/11)	Yes (11/30/11)	Yes (2/9/12)	Yes (5/4/12)		-Will replace Directory #12, Under frequency Load Shedding Program Requirements	Pending FERC Approval
4	BAL-002-NPCC-01	Regional Reserve Sharing	Yes (Thru 11/2/10)	Yes (Thru 12/16/11)	Yes (Thru 1/6/10)						Nomination Form posted - nominations due by 11/10/11	Under Development
5	PRC-012-NPCC-01	Special Protection Systems	Yes (thru 8/18/08)									On Hold

Acronyms:
RSAR- Regional Standards Authorization Request
RRS- Regional Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOD- NPCC Board of Directors
BOT- NERC Board of Trustee

NPCC Document Open Process Executive Tracking Summary

Revised: **7/16/2012**

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Type	Document	Description	Effective Date	Comments	Status
1	Criteria	A-01	Criteria for Review and Approval of Documents			
2	Criteria	A-10	Classification of BPS Elements			
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria			
4	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System			Open Process - comment period through 8/27/12
5	Guideline	B-12	Guidelines for On-Line Computer System Performance During Disturbances			
6	Guideline	B-25	Guide to Time Suynchronization			
7	Guideline	B-26	Guide for Application of Disturbance Recording Equipement			
8	Guideline	B-27	Regional Critical Asset Identification Methodology			
9	Guideline	B-28	Guide for Generator Sequence of Events Monitoring			
10	Procedure	C-00	Listing of NPCC Documents by Type			
11	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures			
12	Procedure	C-05	Monitoring Procedures for Emergency Operation Criteria			
13	Procedure	C-07	Monitoring Procedures for the Guide for Rating Generating Capability			
14	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems			
15	Procedure	C-17	Procedures for Monitoring and Reporting Critical Operating Tool Failures			Open Process - Comment period ended 5/7/12
16	Procedure	C-21	Monitoring Procedures for Conformance with Normal and Emergency Transfer Limits			
17	Procedure	C-25	Procedure to Collect Power System Event Data			
18	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings			
19	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations			
20	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems			Open Process - comment period ended 3/27/11
21	Procedure	C-36	Procedures for Communications During Emergencies			
22	Procedure	C-39	Procedure to Collect Major Disturbance Event Data			
23	Procedure	C-42	Procedure for Reporting and Reviewing System Disturbances			
24	Procedure	C-43	NPCC Operational Review for the Integration of New facilities			
25	Procedure	C-44	NPCC Regional Methodology and Procedures for Forecasting TTC and ATC			
26	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	5/25/2011	[C-45 was previously reserved for CO-12 Seasonal Assessment Methodology (previously proposed but not issued - information included in the CO-12 Working Group scope instead)]	
27	Criteria	A-03 (retired)	Emergency Operation Criteria		A3 retired	Directory #2 established
28	Criteria	A-05 (retired)	Bulk Power System Protection Criteria		A5 retired	Directory #4 established
29	Criteria	A-07 (retired)	Revise Critical Component Definition (Glossary of Terms)		To be retired - pending approval of Glossary	Retired 10/26/11 (correction)
30	Criteria	A-08 (retired)	NPCC Reliability Compliance and Enforcement Program		A-08 retired	CCEP-1 established
31	Guideline	B-21 (retired)	NPCC Guide for Analysis and Reporting of Protection System Misoperations		Superseded by C-45	Replaced by Procedure C-45
32	Guideline	B-22 (retired)	Guidelines for Implementation of the NPCC Compliance Program		B-22 retired	CCEP-1 established
33	Procedure	C-32 (retired)	Review Process for NPCC Reliability Compliance Enforcement Program		C-32 retired	CCEP-1 established
34	Criteria	A-02 (retired)	Basic Criteria for Design and Operation Of Interconnected Power Systems		A2 retired	Directory #1 established
35	Criteria	A-04 (retired)	Maintenance Criteria for Bulk Power System Protection		A4 retired 7/11/2008	Directory #3 established
36	Criteria	A-06 (retired)	Operating Reserve Criteria		A6 retired 12/2/2010	Directory #5 established
37	Criteria	A-11 (retired)	Special Protection System Criteria			Directory #7 established
38	Criteria	A-12 (retired)	System Restoration Criteria		A12 draft replaced by Directory #8 10/21/08	Directory #8 established
39	Criteria	A-13 (retired)	NPCC Inc. Verification of Generator Gross and Net Real Power Capability		A13 retired 12/22/2008	
40	Criteria	A-14 (retired)	Verification of Generator Gross and Net Reactive Power Capability		A14 retired 12/22/2008	
41	Guideline	B-02 (retired)	Control Performance Guide		B2 retired	Content transferred to Directory #5 App. 5
42	Guideline	B-03 (retired)	Guidelines for Inter-AREA Voltage Control		B3 retired	Replaced by Procedure C-40
43	Guideline	B-04 (retired)	Guidelines for NPCC Area Transmission Reviews		B4 retired	Content transferred to Directory #1 App.B

NPCC Document Open Process Executive Tracking Summary

Revised: **7/16/2012**

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Type	Document	Description	Effective Date	Comments	Status
44	Guideline	B-05 (retired)	Bulk Power System Protection Guide		B5 retired	Content transferred to Directory #4 App. A
45	Guideline	B-06 (retired)	Automatic Load Shedding Employing Underfrequency Threshold Relays		B6 retired	Replaced by Guideline B-07
46	Guideline	B-07 (retired)	Automatic Underfrequency Load Shedding Program		B7 retired	Content transferred to Directory #4 App. A
47	Guideline	B-08 (retired)	Guidelines for Area Review of Resource Adequacy		B8 retired	Content transferred to Directory #1 App.D
48	Guideline	B-09 (retired)	Guide for Rating Generating Capability		B9 retired	Replaced by Criteria A-13 Document on July 18, 2007
49	Guideline	B-10 (retired)	Guidelines for Requesting Exclusions		B10 retired	Content transferred to Directory #1 App. E
50	Guideline	B-11 (retired)	Special Protection System Guideline		B11 retired	Replaced by Criteria A-11
51	Guideline	B-13 (retired)	Guide for Reporting System Disturbances		B13 retired	Replaced by Procedure C-42
52	Guideline	B-24 (retired)	Security Guidelines for Protection System IEDS		B24 retired	Content transferred to Directory #4 App. A
53	Procedure	C-03 (retired)			C3 retired	Replaced by Procedure C-36
54	Procedure	C-04 (retired)	Monitoring Procedure for Guides Inter-AREA Volt Control		C4 retired	Content transferred to Directory #1 App. G
55	Procedure	C-08 (retired)	Monitoring Procedures for Control Performance Guide		C8 retired	Content transferred to Directory #5 App. #5
56	Procedure	C-09 (retired)	Monitoring Procedures for Operating Reserve Criteria		C9 retired	Content transferred to Directory #5 App. #2
57	Procedure	C-10 (discontinued)			C10 discontinued	
58	Procedure	C-11 (retired)	Monitoring Procedures for Interconnected System Freq Response		C11 retired	Content transferred to Directory #5 App. #1
59	Procedure	C-12 (retired)	Procedure Shared Activation Ten Minute Reserve		C12 retired	Content transferred to Directory #5 Sect 5.8 & App. #4
60	Procedure	C-13 (retired)	Operational Planning Coordination		C13 retired	Content transferred to Directory #1 App. F
61	Procedure	C-14 (retired)			C14 retired	Procedure C-14 was incorporated in Procedure C-13
62	Procedure	C-16 (retired)	Procedure for Review of New or Modified BPS SPS		C16 retired	Content transferred to Directory #7 App.B
63	Procedure	C-18 (retired)	Procedure for Test & Analysis Extreme Contingencies		C18 retired	Content transferred to Directory #1 App.C
64	Procedure	C-20 (retired)	Procedures During Abnormal Operating Conditions		C20 retired	Content transferred to Directory #5 App. #3
65	Procedure	C-22 (retired)	Procedure for Reporting & Review Proposed BPS Protection Systems		C22 retired	Content transferred to Directory #4 App. A
66	Procedure	C-35 (retired)	NPCC Inter-Area Power System Restoration Procedure		C35 retired	Incorporated within Directory #8 System Restoration
67	Procedure	C-37 (retired)	Operating Procedures for ACE Diversity Interchange		C37 retired	Content transferred to Directory #5 Sect.5.11
68	Procedure	C-38 (retired)	Procedure for Operating Reserve Assistance			Content will be transferred to new Directory #5 Reserve
69	Procedure	C-40 (retired)	Procedures for Inter-AREA Voltage Control		C40 retired	Content transferred to Directory #1 App. G & Directory #2 App. B
70	Procedure	Cost Effectiveness Analysis Procedure - CEAP				Open Process - Comment period through 9/19/11
71	Glossary	NPCC Glossary of Terms				Open Process - Comment period through 9/12/11

Acronyms;

NPCC Directory Executive Tracking Summary

Revised: 7/16/2012 Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Document	Developed From	Description	Version Date	Phase	Task Force Review	Posted Open Process?	RCC Approval?	Full Membership Ballot?	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	12/1/09 (V0)		Under TFCO/CO-8 review				Open Process posting expected in mid December, 2011	Revision Under Development
2	Directory #2	Criteria A-3	Emergency Operations	1/6/11 (V3)		TFCO Review					
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	6/3/09 (V1)						Phase 2 reformatting pending	
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	12/1/09 (V0)						TFSP expects to begin Phase 2 review of Directory #4 in early 2012.	
5	Directory #5	Criteria A-6	Reserve	12/2/10 (V0)			Yes (Thru 6/25/12)				Revision Under Development
6	Directory #6		Regional Reserve Sharing		2		Yes (Thru 4/6/12)		Passed 04/09/2012		
7	Directory #7	Criteria A-11	Special Protection Systems	12/27/07 (V0)						Post for member comment is expected after the November 2011 TFSP Meeting	
8	Directory #8	Criteria A-12	System Restoration	10/22/10 (V1)						Reformatting of Directory #8 which will be addressed by CO-8 early next year	
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	7/7/09 (V1)	2		Yes (Thru 12/28/11)		Passed 12/28/11		Phase 2 Reformatting
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	7/7/09 (V1)	2		Yes (Thru 12/28/11)		Passed 12/28/11		Phase 2 Reformatting
11	Directory #11										
12	Directory #12		Under frequency Load Shedding Program Requirements	1/6/11 (V2)			Yes (Thru 1/21/11)			V2 - Errata	Will be replaced by Regional Standard PRC-006-NPCC-01

Acronyms:
MC - Members Committee
RCC - Reliability Coordinating Committee

May 17, 2012

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Docket No. RM10-23-001

FERC Denies Rehearing of Transmission Planning and Cost Allocation Rule

The Federal Energy Regulatory Commission (FERC) today upheld its Order No. 1000 reforms to transmission planning and cost allocation, finding that existing requirements are inadequate and threaten to thwart the development of transmission that is more efficient or cost-effective for users of the grid.

Today's order denies rehearing of the July 2011 final rule establishing minimum criteria that a transmission planning process must satisfy, including general principles for cost allocation methods. These transmission planning requirements involve the development of regional plans, consideration of transmission needs driven by public policy requirements established by state or federal laws or regulations, and coordination between pairs of neighboring transmission planning regions.

Regional and interregional cost allocation methods must meet certain principles, including that allocated costs be "roughly commensurate" with estimated benefits, and that those who do not benefit from transmission do not have to pay for it. Participant-funding of new transmission facilities is permitted but cannot be used as the regional or interregional cost allocation method.

The order also affirms the Commission's actions in Order No. 1000 to promote competition in regional transmission planning by removing from Commission-approved tariffs and agreements any federal right of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, subject to certain limitations.

While denying rehearing, the order provides a number of clarifications, including:

- Each planning region must have a clear enrollment process that defines how entities, including non-public utility transmission providers, make the choice to become part of the region.
- Claims that a federal right of first refusal in a Commission-approved agreement is protected by a *Mobile-Sierra* provision are properly made as part of an Order No. 1000 compliance filing. Before addressing proposed tariff revisions to comply with the rule, FERC will decide whether the agreement is protected by a *Mobile-Sierra* provision, and if so, whether the applicable standard of review to require removal of the right of first refusal has been met.
- The transmission planning process is not intended to assess the merits of federal or state public policy requirements, but to help utilities comply with those requirements by considering new transmission facilities driven by such requirements.

Each public utility transmission provider must submit its Order No. 1000 compliance filing by October 11, 2012. Compliance filings for interregional transmission coordination and interregional cost allocation are due in April 2013.

R-12-18

(30)

May 17, 2012

Commissioner Cheryl A. LaFleur

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. RM10-23-001

Item No. E-1

Statement of Commissioner Cheryl A. LaFleur on Rehearing of Transmission Planning and Cost Allocation Rule

"Today, we act on the petitions for rehearing of Order No. 1000, affirming the determinations of our earlier order, while clarifying several points. I am pleased to support today's Order.

Our nation is making a substantial investment in its interstate transmission network. As noted in the Order, a study by the Brattle Group estimated that between 2010 and 2030, close to $300 billion in new transmission facilities may be required. Transmission is needed to strengthen reliability, reduce congestion costs, and connect new resources driven by state and federal public policy requirements. I continue to believe that the Commission's rule on planning and cost allocation will help ensure that the most efficient and cost-effective transmission solutions are the ones that are chosen and constructed.

There is one particular point in the Order that I wish to emphasize.

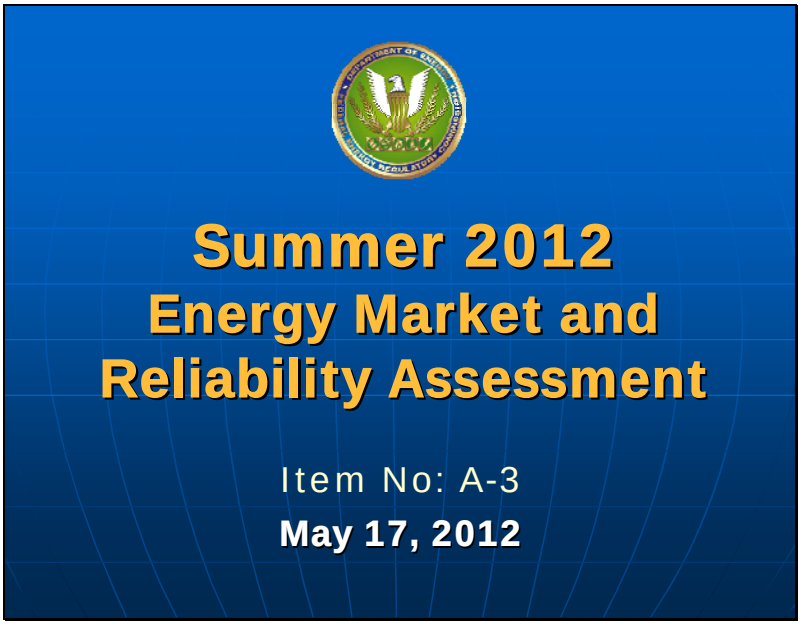
Today's Order, in discussing the Commission's jurisdiction over transmission under Section 201 of the Federal Power Act, notes previous findings that the interconnected transmission grid functions as a "single machine" whose flows are determined by the laws of physics. However, as the Order also correctly notes, this physical reality does not in itself dictate beneficiaries and the just and reasonable allocation of the costs of new transmission. The fact that electric energy flows broadly across a given interconnection does not imply that costs must be correspondingly allocated. Rather, a regional cost allocation method must satisfy the principles set forth in Order No. 1000 and affirmed here, including that the costs of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is roughly commensurate with estimated benefits.

I view this as the central principle of cost allocation in Order 1000. In addition, as I indicated in my dissenting opinion in the Commission's recent order in the Opinion No. 494 proceeding,[1] I believe on compliance we should be open to different applications of this principle that reflect the facts and circumstances of different regions.

I know that public utility transmission providers across the country are working hard on compliance with Order No. 1000. I appreciate the FERC staff's work to draft Order No. 1000-A in a timely manner, and hope that it helps these compliance efforts move forward. I look forward to reviewing the compliance filings we receive, and to supporting the efforts of regions across the country to build transmission that is needed by customers for reliability, economic, and public policy reasons."

[1] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 (2012).

Slide 1



Mr. Chairman, Commissioners, good morning. We are pleased to present the Summer 2012 Energy Market and Reliability Assessment, which is a joint effort of the Office of Enforcement and the Office of Electric Reliability.

Slide 2



The key takeaways from today's presentation are as follows:
Robust supplies of natural gas have led to the lowest sustained natural gas prices since 2001. This market trend is expected to continue to place pressure toward generally lower electricity market prices;

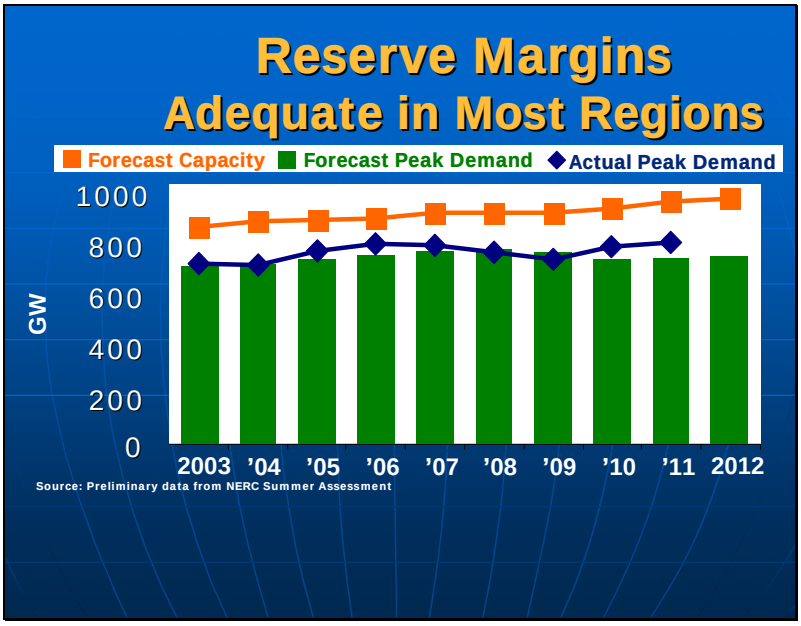
With the outage of two San Onofre nuclear units, supply-demand conditions in Southern California, and particularly in the San Diego area, warrant close attention to electric grid operations and electricity market prices if the two units should remain offline during high load periods this summer;

The generation supply in Texas may be strained if the state experiences another hot summer like last year;

However, overall in the rest of the country, capacity reserves appear adequate; and

The shift from coal-fired to natural gas-fired generation will have limited market effects.

Slide 3



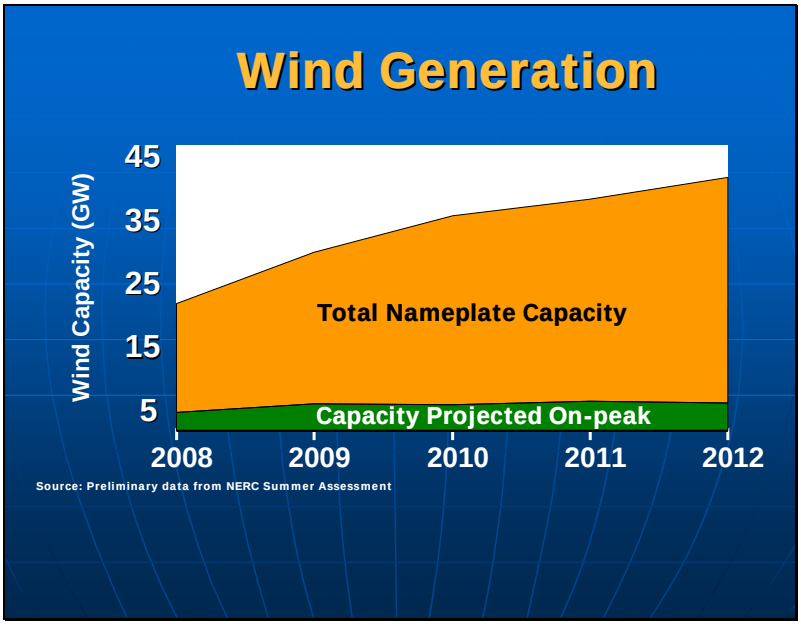
Thank you Alan.

Preliminary data from NERC's Summer Assessment indicates that reserve margins are projected to be adequate in most, but not all, regions of the country this summer. Some areas, such as ERCOT, are projecting a small amount of load growth, while other areas, such as New England are projecting that loads will remain flat or decline. Overall, NERC forecasts that the total US load, when weather adjusted, will decline by less than one percent when compared to last year.

In Texas, ERCOT is forecasting a reserve margin of 13.3 percent, which is below its reserve margin target of 13.75 percent. For California, WECC is forecasting a reserve margin of 15.2 percent, slightly above the reserve margin target of 15.1 percent.

Under normal weather and system conditions, New England's electric power supplies are expected to be adequate this summer. However, reduced and uncertain supplies of Liquefied Natural Gas to fuel the Mystic Generating Station could result in an inadequate supply to the Greater Boston area during extremely high loading periods and multiple contingency conditions. ISO New England is reaching out and working with asset owners in North East Massachusetts and the Boston area to alert them to the situation and is working with local generation and transmission companies to develop special operating plans that can be used to manage a shortage situation.

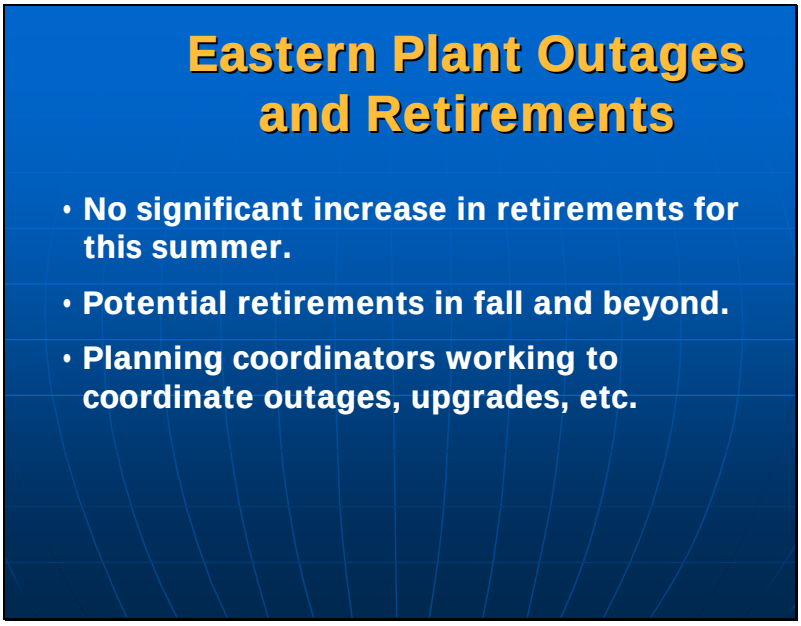
Slide 4



The NERC Summer Assessment reports that the projected summer installed nameplate wind capacity will increase by about 3.4 GW, or about 9 percent from 2011, for a total nameplate capacity across the nation of approximately 40 GW.

The average on-peak wind capacity for the 2012 summer is forecast to be 11 percent of nameplate capacity. The on-peak capacity forecasts reflect the differing wind characteristics across the country, and range from lows of 2.2 percent of the nameplate capacity of 4.5 GW in the Southwest Power Pool to a high of 26 percent of the nameplate of 1.2 GW in Mid-Continent Area Power Pool.

Slide 5

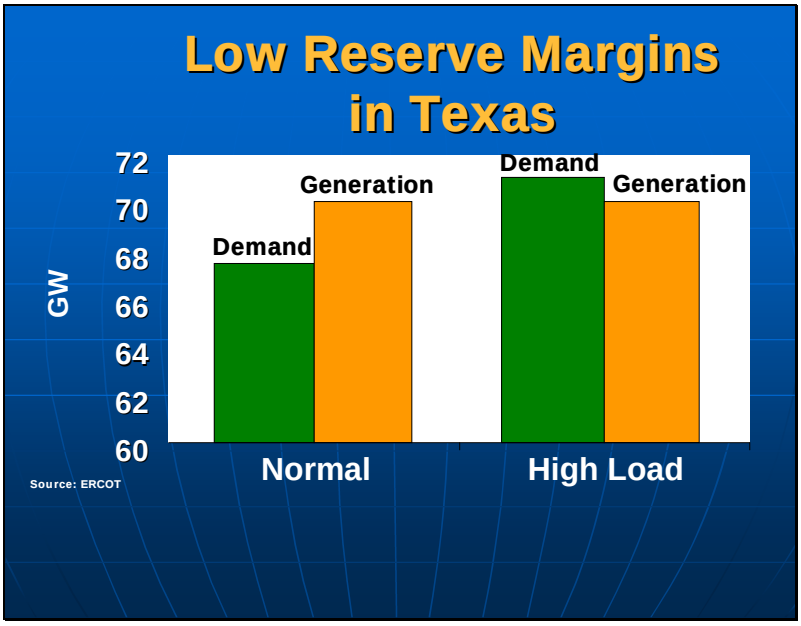


A number of utilities in the Eastern Interconnection have announced intentions to retire older fossil fuel generating units over the next few years, with some retirements in PJM beginning as early as this fall. According to NERC and the Regions, plant retirements are not projected to affect reliability for this summer, and appear to represent normal generation fleet turnover. Similarly, NERC and the Regions report that the planning coordinators continue to work with their generation and transmission owners to manage any maintenance outages related to plant retrofits or upgrades.

Looking ahead to the fall, FirstEnergy has announced plans to retire generating units totaling approximately 3.4 GW in its service territory in northern Ohio and western Pennsylvania. PJM and the transmission owners are coordinating transmission upgrades, reliability must-run agreements, and projects and procedures to allow continued reliable operations in this area.

The NERC Long-Term Reliability Assessment, which will be released in the fall, will provide additional information on projected resource adequacy in future years.

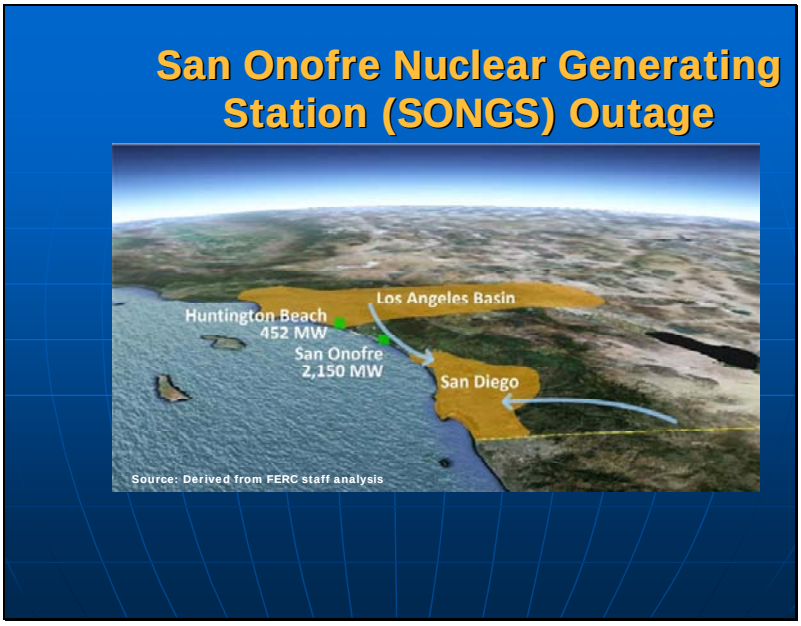
Slide 6



ERCOT is projecting a reserve margin of 13.2 percent, assuming that normal weather conditions occur in Texas this summer. This projected reserve margin will be approximately one half of a percentage point below its reserve margin. ERCOT also projects that forecasted load could exceed projected capacity during an extreme heat wave with higher-than-normal forced generation outages. ERCOT forecasts that over 1.4 GW of demand response will be available to operators during periods of peak demand, and may obtain additional load reductions from public appeals for conservation and price-sensitive demand.

According to NERC and ERCOT, the low reserve margins in Texas are due largely to load growth outpacing generation development. ERCOT has continued to experience load growth through the recession, and several years of hot summer weather have contributed to an increasing load forecast. While drought remains a concern in Texas, ERCOT projects that winter precipitation was sufficient to maintain reservoir levels and provide sufficient cooling water through the summer months.

Slide 7



In Southern California, the San Onofre Nuclear Generating Station between Los Angeles and San Diego has been shut down for repairs. Without the 2.3 GW from this plant, NERC forecasts that projected reserve margins in California may be close to, but still be above, the regional target of 15.1 percent. The extended plant outage will also limit transfers into the San Diego area from the Los Angeles basin. Two mothballed units at Huntington Beach have been reactivated, and will provide additional capacity in the Los Angeles basin and support additional transfers into San Diego. Entities in the area are also working to increase demand response and conservation measures in southern Orange County and San Diego. Alan…

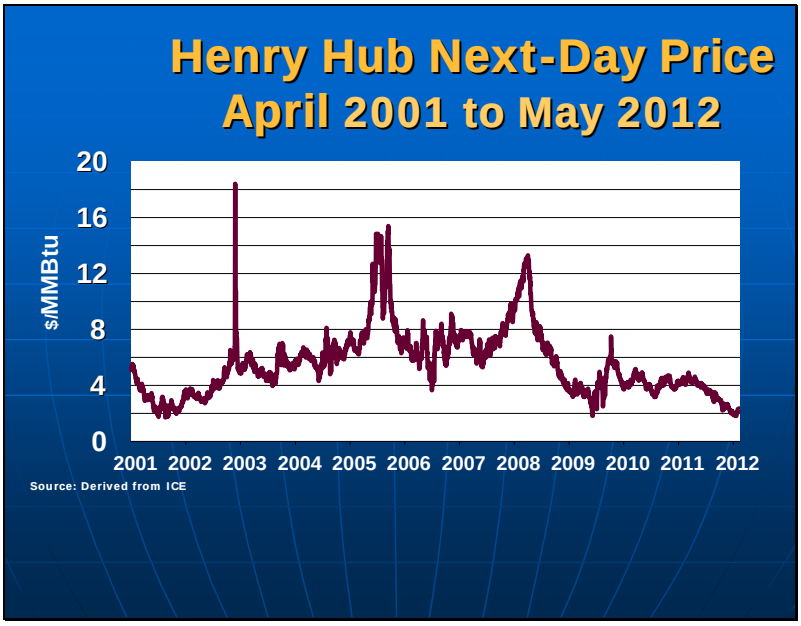
Thank you, David.

In addition to the reliability concerns David just described, if the San Onofre Nuclear Generating Station units continue on outage into the summer the market impacts could extend beyond the San Diego area. In particular, Southern California, which includes the transmission zones of both San Diego Gas & Electric and Southern California Edison, may see elevated prices compared to Northern California and neighboring regions, especially during periods of high demand. With the region reliant on imports, the removal of the two SONGS units means the region will need to rely on plants with higher costs. Greater price volatility typically occurs under such situations.

The ultimate impact on customers should be at least partially buffered, with the local load-serving entities having physical capacity, purchase agreements, and Congestion Revenue Rights. Few customers pay bills based on the real-time price, but high real-time prices work their way into day-ahead prices and longer-term instruments if they are sustained.

Staff will follow the market operations closely, including the supply and demand conditions and any market participant behavioral issues.

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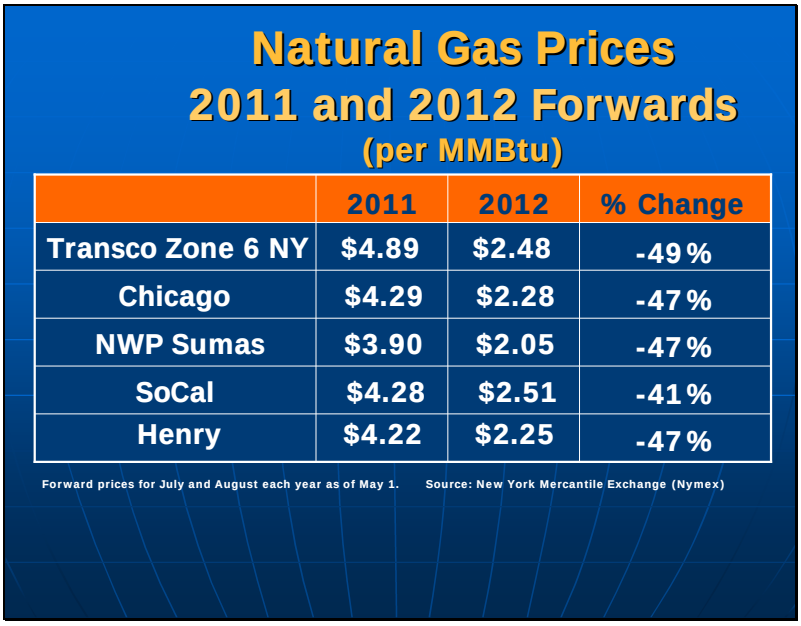


The most prominent market driver for energy markets this summer will be the cost of natural gas, which has fallen to prices last seen a decade ago. In staff's 2011 State of the Markets Report last month, staff showed how prices have declined throughout 2011. This decline to below $3 per MMBtu has continued into 2012.

Gas prices at the recent lower level can be expected to have a significant impact on electric markets. Gas prices in the $2-$2.50 price range place downward pressure on electricity prices generally, and moves some dispatch to natural gas from coal, which I will discuss later.

Staff expects that surplus-gas conditions will continue through the summer. Overall, with these market conditions, natural gas prices can be expected to stay near their present levels.

Slide 9

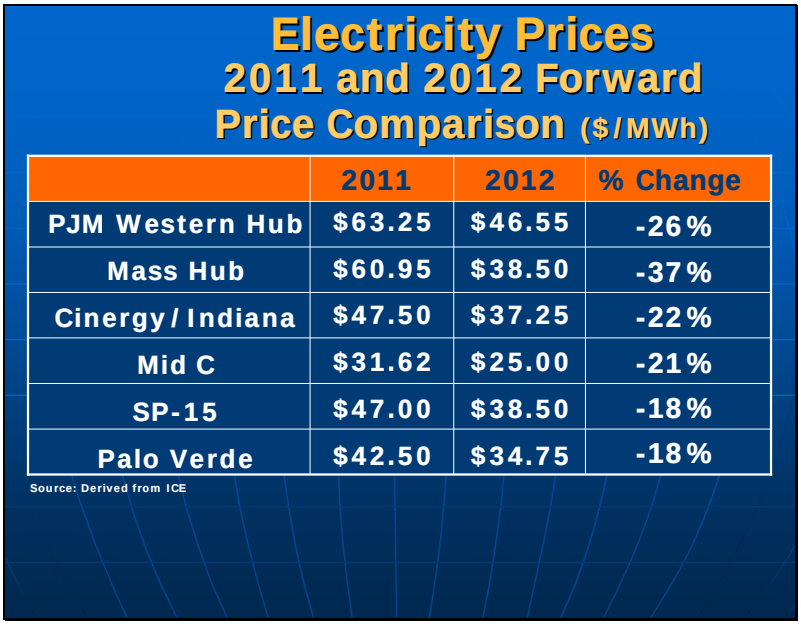


This chart compares forward natural gas prices for last summer with forwards for this summer. Staff looks at forward prices for the peak summer months of July and August for perspective on how market participants currently view the dynamics affecting seasonal prices. Staff does not view forward prices as a predictor of actual prices, but analyzing the trends in the forward prices can help to understand market factors heading into summer. The sharp contrast between what summer forwards are today and what they were in 2011 shows that the forward markets expect that the current natural gas surplus in supply will continue to be the price driver over this period.

With storage already filling as we enter summer and production levels continuing at a robust level, physical fundamentals indicate that natural gas prices will continue at lower levels compared to recent years.

While regional differentials persist, there is much less variation than in years past. New pipeline infrastructure, such as the Ruby Pipeline, the new Florida Gas Transmission expansion and Rockies Express has linked new supply sources to demand markets and reduced bottlenecks significantly. The differences that do arise in basis are limited in magnitude. Also, basis differences derive from temporary conditions such as weather-driven demand in the Northeast, driving basis higher, or from supply surplus in the Northwest, driving basis lower.

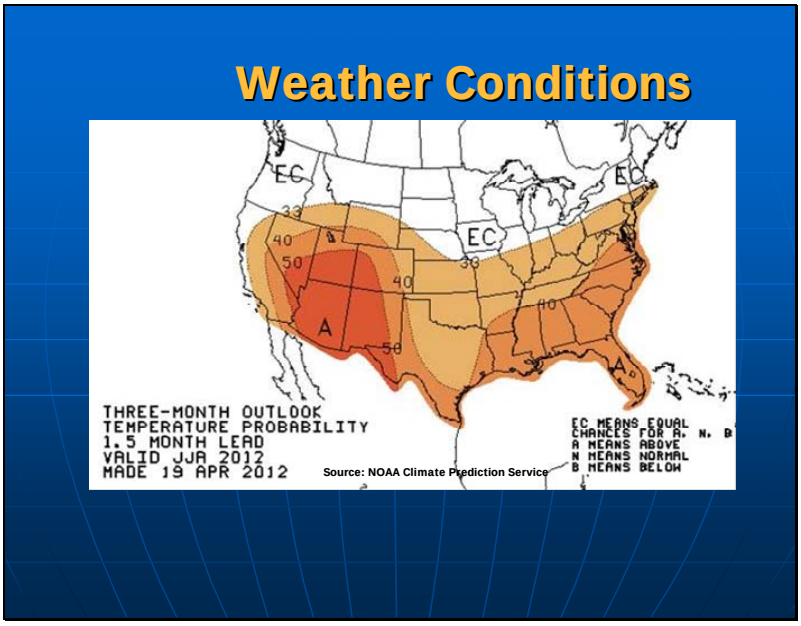
Slide 10



This chart compares electricity forward prices for this summer as of May 1st with electricity forwards from last year. The forward prices indicate that market participants expect lower prices than a year ago. The chart shows that prices for the forward summer strip this year are $7 to $22/MWh less than similar forwards a year ago.

As noted, staff does not view forwards as a price forecast, but, rather, perspective on how the various market participants view market conditions. This is particularly true for electric prices. The weather impact on electric prices can introduce large swings that cannot be predicted months in advance. Typically, because the market does not know for certain how hot the summer will be, it takes a weather-normalized view of load levels and their effect on price when contracting forward.

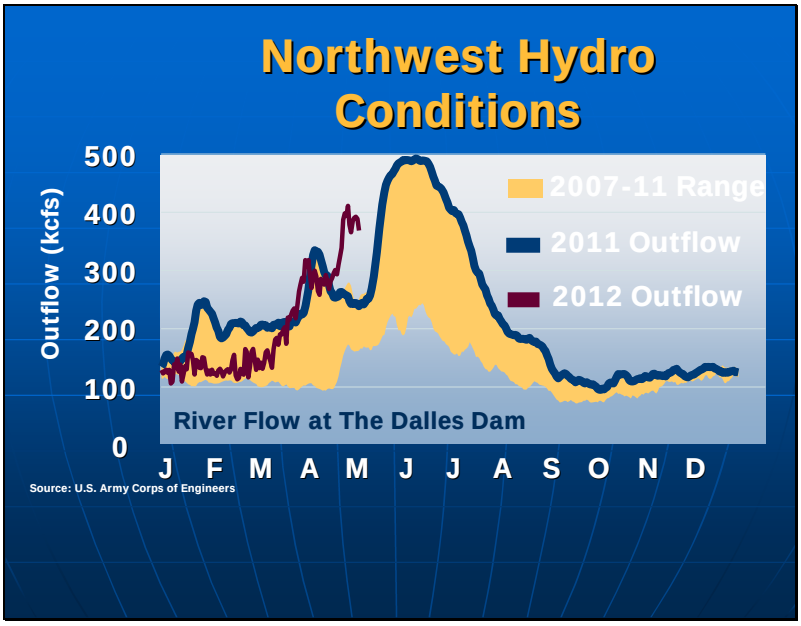
Slide 11



NOAA predicts a warmer-than-normal summer across most of the country. The only exceptions are parts of the Pacific Coast and the northern tier of the nation, where normal temperatures are expected. The greatest chance of above-average temperatures is the area centered around Arizona and New Mexico. NOAA also sees an increased chance of below-normal precipitation in the Northwest through the summer months.

Early forecasts for the hurricane season from Colorado State University call for lower-than-normal activity for the Atlantic this summer. It predicts 10 named storms, of which 4 will become hurricanes, and 2 of those 4 will become major hurricanes, category 3 or greater. Six hurricanes are considered normal for a season. When assessing the impact of hurricanes, an important factor to keep in mind is the geographical change in U.S. production. In 2005, before the shale gas revolution, the double hit from hurricanes Katrina and Rita sent gas prices soaring through large portions of the U.S. market. By 2008, shale gas added more than 9 Bcf to daily production, and another double-hurricane hit that summer (hurricanes Gustav and Ike) caused barely a ripple in gas prices. New onshore production less vulnerable to hurricanes, pipeline infrastructure additions, additional Gulf Coast storage and LNG terminals have added diversity of supply options and flexibility to the system that minimize the effects of hurricanes on natural gas markets.

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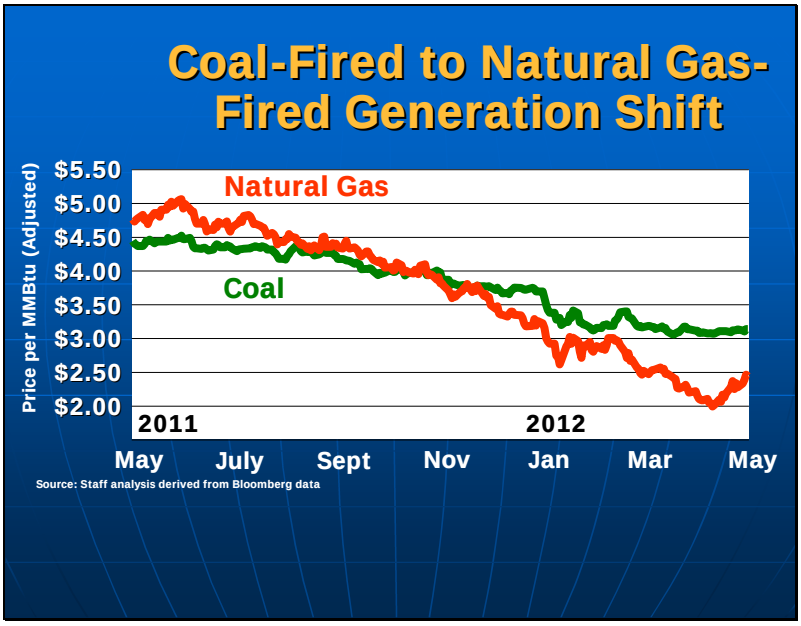


Conditions for hydroelectric generation in the West are mixed. Snowpack in British Columbia and parts of the U.S. Northwest came in at average or above-average levels. California, on the other hand, is well below average. The Pacific Northwest reached 98 percent of average snowpack as of April 1, the historical peak snow accumulation date, while California was 60 percent.

This means that conditions likely will support significant hydroelectric production in the Northwest. Inside California, available hydroelectric generation is expected to be somewhat below average. While snowpack levels are low, reservoir levels are closer to normal owing to good hydrologic conditions last year. The expected abundance of hydro production in the Northwest will benefit the California and Southwest markets. As is typical of normal hydro conditions, transmission lines from the Northwest into California can be expected to be well loaded during the spring and going into the summer.

Even though hydro conditions are not expected to be as flush as a year ago, BPA sees a high likelihood that there will be some over-generation as a result of river and hydro-electric facility protocols designed to protect fish. Over-generation may, in turn, lead to curtailments of non-hydro resources, which has already occurred this spring. The financial markets may see negative prices during some over-generation conditions. Other regions such as ISO New England, New York ISO, and MISO use hydroelectric generation as part of their generation mix, both from internal generation within each region and from Canadian imports. None of these areas is as dependent on, or influenced by, hydro conditions as the Northwest and California. Based on hydro conditions in the eastern regions, we do not see any notable market issues to report. In the past there have been concerns about drought conditions in some areas and the availability of cooling water. Some regions, such as the Southeast and the Southwest are expected to be under drought conditions this summer, but these conditions are not expected to be severe enough to cause concern about the reliability of generators that depend on water supplies for cooling.

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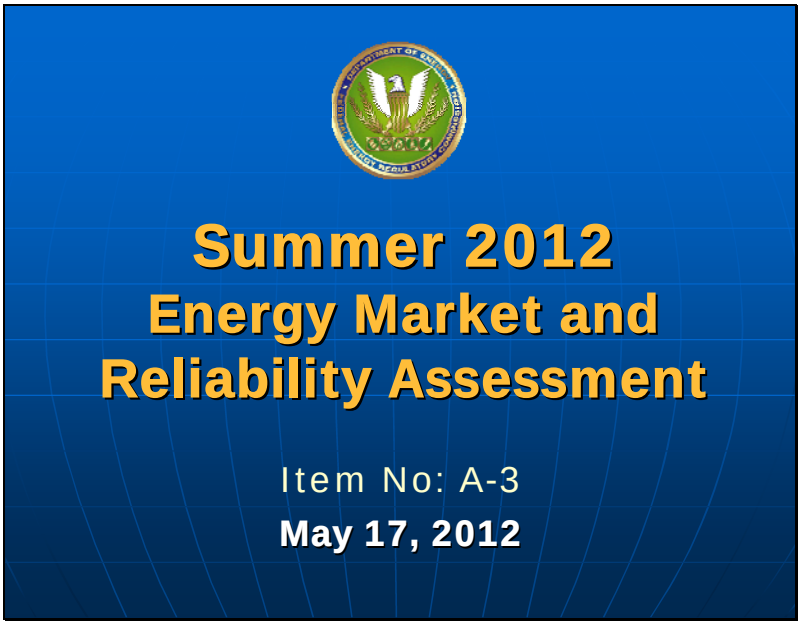


As noted, the low cost of natural gas is expected to continue to exert downward pressure on electricity prices this summer. We expect the ongoing substitution of natural gas-fired generation for coal-fired generation to continue as a result of these low gas prices. When the cost of natural gas dropped below $4 per MMBtu, combined cycle units started competing on price with coal-fired steam units using Central Appalachian coal. The graph above shows a crossover in favor of natural gas in the fall of 2011. The comparison is on an MMBtu basis adjusted for typical heat rate of natural gas and coal-fired units. In regions such as MISO, PJM, and the Southeast for example, where there is significant coal-fired capacity as well as natural gas-fired capacity, use of the installed natural gas-fired generation has grown as use of coal resources has dropped.

The ability of the natural gas-fired plants to obtain sufficient fuel does not appear to be a significant factor or a market concern during the upcoming summer. In particular, capacity in long-haul pipelines is generally sufficient to avoid disruptions in the use of natural gas for electric generation for this summer.

The switch-over from coal to natural gas can be expected to lower coal plant revenues. In addition, some coal plant owners may reduce their offers in order to keep running because they need to manage their coal piles. This is because many coal-fired plant owners entered into contracts determining price and delivery schedules when conditions were different.

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This concludes our prepared presentation. I would like to express gratitude to the many staff members in the Office of Electric Reliability and the Office of Enforcement who contributed to this report.

We are happy to answer any questions you may have.

May 17, 2012

Commissioner John R. Norris

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-23-001

Item No. E-1

Statement of Commissioner John R. Norris on Rehearing of Transmission Planning and Cost Allocation Rule

"As I have been traveling the country and talking with the public about the Commission's work over this past year, Order No. 1000 has, understandably, been one of the biggest topics of discussion. I know that the Final Rule is viewed from many different perspectives, but it is clear that everyone sees it as a major rulemaking with significant implications for the future. Regions are now working their way through the process of structuring their compliance filings. My hope is that today's order provides entities that must comply and other stakeholders much needed guidance and certainty as they work through that process.

It is important to view Order No. 1000 in the broader context of the systemic changes confronting the transmission grid. We are at a crossroads with respect to our energy future. This is an important moment, one that is defined by rapid change and uncertainty. New resources are providing more and more of our generation mix. Natural gas is abundant and cheap. Industry is responding to multiple challenges, from the integration of renewables, to new mandatory reliability standards, to compliance with environmental regulations. This industry and all of us in it have a lot of on our plate.

I believe that how we respond will say a lot about us. Do we decide to work together and plan for the most efficient and cost-effective modern grid that responds to all of these challenges and meets regional needs in an open and transparent manner? Or, do we respond to these problems with disjointed planning that can lead to the construction of duplicative or inefficient solutions to meet regional needs, and ultimately result in higher costs for consumers?

Order No. 1000 is a call for those within each region to work together to find efficient and cost-effective solutions that meet that particular region's needs. We recognize that there should not be a one-size-fits-all solution so we allowed significant regional flexibility in meeting the requirements of the Final Rule. I see this as an essential element of this rulemaking.

Non-jurisdictional utilities are also looking carefully at the implications of Order No. 1000. Today's order responds to the issues these entities brought before us on rehearing and compliance. I encourage non-jurisdictional utilities to engage in the compliance process in their regions, and ultimately in the regional transmission planning process that result from the compliance process. Non-jurisdictional utilities are no less impacted by the profound changes in our energy system, and the enhanced regional planning Order No. 1000 will establish can greatly benefit these entities in managing this transition. Moreover, many of the regional transmission planning processes being contemplated would be severely impaired if they did not include non-jurisdictional entities. The bottom line is that we need each other to move forward. While today's order may not give non-jurisdictional utilities all of the answers they were hoping for, I'm committed to continuing to work with such entities to find ways for them to meaningfully engage in the process and meet the needs of their customers.

Finally, I know that states are assessing what Order No. 1000 means for them. As a former state regulator, I understand the pressures that states are under to meet diverse needs within their own states. You are the ones on

the ground in each of your states and you know best how to meet those needs. I believe that the Final Rule does not take anything away from your ability to do just that. Instead, it gives you more tools in your toolbox to accomplish your many goals. I heartily encourage states to utilize these tools and participate in the compliance process, and in the actual regional transmission planning processes that will follow. The states' input is essential to making this all work. I look forward to proposals from public utilities that would formalize a state role in these processes."

Document Content(s)

E-1-NORRIS-05-17-12[1].DOC.....1-2

May 17, 2012

News Media Contact
Craig Cano | 202-502-8680

Docket No. PL12-1-000

FERC Approves Policy Outlining its Role in EPA's New Mercury Rule

The Federal Energy Regulatory Commission (FERC) today approved a policy statement outlining how it will advise the Environmental Protection Agency (EPA) on requests for extra time for electric generators to comply with the new mercury and air toxics standards rule. The process addresses the need for timeliness, fairness and transparency while respecting FERC jurisdiction over reliability of the bulk power system.

FERC's policy takes into account comments filed in response to the January 30 staff White Paper, and is limited in scope as to how the Commission will provide advice to EPA. This is not a policy regarding how FERC will handle all electric reliability concerns arising from compliance with EPA regulations.

"This policy statement outlines FERC's advisory role within a narrow provision of the EPA rule," FERC Chairman Jon Wellinghoff said. "Outside the narrow scope of this advisory role, FERC will continue to address these matters in our public forums, review information regarding the impact of compliance on reliability of the grid and consider if we need further steps to monitor how these regulations will affect the reliability of the grid."

EPA gives generators three years to comply with its rules. Some generators will be eligible for a one-year extension and, if necessary, an additional year if they need to meet specific reliability concerns. FERC's policy statement deals with this final year to comply. Any decision on whether to grant this additional time, and the extent to which FERC's advice is considered, rests entirely with EPA.

Under the FERC policy statement:

- Generators should submit to FERC as informational filings copies of their requests to EPA for extra time for compliance.
- FERC's Office of Electric Reliability will lead the review of the filings under the Commission's general investigative authority; the reviews will examine whether compliance with EPA's rule could result in a violation of a FERC-approved reliability standard or other issues within FERC's jurisdiction.
- There are no specifically required analyses to show that operation of a generating unit beyond the compliance date is critical to maintain reliability, though informational filings should provide the types of data used by the Commission to examine potential violations of its mandatory reliability standards, such as system planning and operations studies, system restoration studies or plans, operating procedures and mitigation plans.
- The Commission will not seek comment on the informational filings, though EPA requires that requests for extra time contain any written comments by other parties. The EPA policy encourages such comments, which should be included in the informational filings.

FERC also encouraged EPA to seek advice from other reliability experts, including state regulators, regional market operators, planning authorities and the North American Electric Reliability Corp. and its affiliated regional entities.

Finally, the Commission will vote on its comments before providing them to EPA, but this will not constitute a final determination that a reliability standard has or will be violated, nor will it be considered a final agency action that would trigger civil penalties or other enforcement actions.

R-12-19

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Document Content(s)

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20120525-3031 FERC PDF (Unofficial) 05/25/2012

May 25, 2012

Commissioner John R. Norris

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Statement of Commissioner John R. Norris on U. S. Senate Confirmation

"I am honored to be confirmed for a full term as a Commissioner at FERC and thank President Obama and the U.S. Senate for the opportunity to continue serving the American people. The energy issues we work on at FERC are critical to our nation's economy and to the safety and well-being of our citizens. I look forward to continuing to form partnerships that strive to ensure consumers have access to reliable and efficient energy services."

20120525-3031 FERC PDF (Unofficial) 05/25/2012

Document Content(s)

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June 21, 2012

Chairman Jon Wellinghoff

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket No. IN12-16-000

Item No. A-3

Statement of Chairman Jon Wellinghoff on Vegetation Management Best Practices

"A recurring cause in this and many blackouts has been vegetation-related outages. Environmental issues, property rights and cost, among other things, play an important role in every company's vegetation management program. In my view, the most successful vegetation management program have, as one of the core elements, a strategy to engage the property owners in an adequate, timely and forthright manner and to work cooperatively with those property owners.

For example, it is important to give the property owner sufficient notice about the impending activity including the type of vegetation management that is planned - for instance trimming or herbicide application. In some cases, a company may get the property owner to agree to the planned action by simply switching methodologies say from herbicide application to trimming.

Successful vegetation management programs also help property owners maintain and even enhance the environmental benefits and aesthetics of the right-of-way while ensuring sufficient clearance between the vegetation and energized conductors. For example, trees that are expected to grow into the transmission lines are removed and replaced with lower growing native species that provide a shelter for indigenous wildlife. Another practice that property owners appreciate is a small tree voucher program that allows them to select smaller trees from nurseries to replace the larger trees that are removed from the right-of-way. These efforts may even help persuade property owners to allow vegetation management outside of both jurisdictional facilities and the existing right-of-ways.

The current reliability standard FAC-003 requires both a formal transmission vegetation management plan and an annual plan for vegetation management work. I believe that companies should make these plans available to the public, including the affected landowners, by posting them on their website.

I urge all companies to include these components in their vegetation management programs.

As a final point, we continue to receive complaints that utilities are clear-cutting right-of-ways in order to comply with reliability standard FAC-003. In some cases, reliability standard FAC-003 has been cited as the reason for clear-cutting even when it does not apply, e.g. transmission lines below 200 kV and distribution lines. The standard only requires that a minimum clearance be maintained and does not prescribe the methodology that utilities are required to use. Companies should not misrepresent the reason for the vegetation action by overstating the requirements or applicability of the standard."

20120621-3060 FERC PDF (Unofficial) 06/21/2012

Document Content(s)

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June 21, 2012

Commissioner Cheryl A. LaFleur

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. : **RM12-6-000 and RM12-7-000**

Item No.: E-4

Statement of Commissioner Cheryl A. LaFleur on NERC's Revised Definition for Bulk Electric System

"Almost two years ago, in Order No. 743, the Commission directed NERC to redefine the term "bulk electric system" (BES). The Commission explained that the current definition gives Regional Entities broad discretion to identify BES facilities, which has resulted in inconsistencies across regions and potential gaps in reliability.

In my remarks at the time, I observed that the Commission used Order No. 743 to establish a new paradigm for Commission directives under section 215(d)(5) of the Federal Power Act. The Commission explained that directives should not be unduly prescriptive, but should instead identify and explain the Commission's reliability concerns, offer NERC guidance and suggestions as to acceptable solutions, and permit NERC to propose equally efficient and effective alternatives.

I am pleased that the Commission has adhered to this formula since Order No. 743 and I expect it to continue to do so. I am also pleased that NERC has responded to our challenge in Order No. 743 by proposing a definition that eliminates regional discretion, establishes a general bright-line threshold of 100 kV, contains a thoughtful and nuanced list of specifically included and excluded facilities, and provides an exception process to add or remove specific facilities.

While I believe that NERC has succeeded in addressing the Commission's technical concerns, and therefore support the NOPR, I note that the NOPR seeks comment on the status of facilities under several specific fact patterns. As the NOPR states, these questions are intended to develop a common understanding among the Commission, NERC, and the regulated community of how the new definition applies in certain ambiguous circumstances.

Additionally, the NOPR seeks comment on whether NERC has successfully excluded local distribution facilities from the BES. As I noted in a recent dissent,[1] section 215 of the Federal Power Act specifically excludes local distribution facilities from the Commission's reliability jurisdiction. The Commission must respect this limit on its jurisdiction. I also noted that in Order No. 743-A, the Commission deferred to this proceeding the critical question of whether the local distribution facilities excluded from the Commission's jurisdiction under section 215 are the same local distribution facilities excluded from the Commission's jurisdiction under section 201(b). I look forward to receiving comments on these important issues.

Finally, I want to thank Bob Stroh, Susan Morris, Nick Snyder and the entire FERC team for their diligence in participating in the Standards Development Process and for their hard work on this order. I also want to recognize and thank the NERC drafting team for developing a thoughtful and robust definition and for completing your work on time. I know that you, like all drafting teams, are volunteers and that your work on the definition was in addition to your day jobs at your companies. I appreciate your hard work and commitment to reliability."

[1] *City of Holland, Michigan Board of Public Works*, 139 FERC ¶ 61,055 (2012) (*Comm. LaFleur, dissenting*).

June 21, 2012

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Docket Nos. RM10-11-000

FERC Approves Final Rule to Integrate Variable Energy Resources

The Federal Energy Regulatory Commission (FERC) today issued a final rule that promotes more efficient operation of the transmission system amid increasing integration of variable energy resources and benefits electric consumers by ensuring that services are provided at just and reasonable rates.

Today's rule adopts two reforms from a November 2010 Notice of Proposed Rulemaking (NOPR) by requiring transmission providers to offer customers the option of scheduling transmission service at 15-minute intervals and by requiring generators using variable energy resources to provide transmission owners with certain data to support power production forecasting. Although the rule does not require the standard approach to generator regulation service proposed in the NOPR, it gives guidance on how the Commission will evaluate proposed charges for that service.

"Variable energy resources make up an increasing share of new capacity coming on-line," FERC Chairman Jon Wellinghoff said. "This final rule eliminates undue burdens on these resources and will help transmission providers and their customers effectively manage the costs of integration."

The rule finds that transmission customers are exposed to excessive imbalance service charges because they cannot adjust their service schedules within each operating hour. Intra-hour scheduling gives customers the tool they need to manage that exposure when generation output changes within the hour.

The rule allows transmission providers to submit alternative proposals that are consistent with or superior to the 15-minute scheduling reform. Any alternative proposal will need to provide equivalent or greater opportunities for transmission customers to mitigate generator imbalance penalties and for the public utility transmission provider to lower its reserve-related costs.

The final rule finds that while power production forecasts help transmission providers manage reserves more efficiently, forecasts are only as good as the data on which they rely. By requiring new interconnection customers whose generating facilities are variable energy resources to provide meteorological and operational data to transmission providers engaging in power production forecasting, FERC finds that transmission providers will better be able to manage resource variability.

In response to comments calling for flexibility in the design of reserve capacity services needed to efficiently integrate variable energy resources, the Commission decided not to require transmission providers to add to their tariffs a new schedule for generator regulation service. FERC will continue to evaluate proposed charges for that service on a case-by-case basis, and the rule provides a framework for transmission providers to develop proposed charges. The rule notes that public utility transmission providers that decide to file with the Commission to impose such a reserve capacity charge should, as part of any filing, account for the reserve costs savings associated with the reforms FERC adopts in this final rule.

The final rule takes effect **12** months after publication in the *Federal Register*.

R-12-22

(30)

May 2012
Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its May 17, 2012 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

E-1 – Press Release
E-5 – Press Release

FERC initiates an investigation of MISO formula rate protocols under Federal Power Act section 206

E-3, *Midwest Independent Transmission System Operator, Inc., et al.*, Docket No. EL12-35-000. The order initiates an investigation under section 206 of the Federal Power Act and establishes paper hearing procedures to determine whether the formula rate protocols under the transmission tariff of the Midwest Independent Transmission System Operator, Inc. (MISO), as well as the formula rate protocols that each of the MISO transmission owners have on file with the Commission, are sufficient to ensure just and reasonable rates. The formula rate protocols essentially establish a vetting process for the MISO transmission owners' formula rate inputs. Specifically, the order identifies three areas of concern with the current protocols: (1) the scope of participation in this process, i.e., who will have access to information concerning the transmission owners' formula rate inputs; (2) the transparency of the information provided by transmission owners, i.e., what information is provided; and (3) the ability to challenge transmission owners' implementation of the formula rate, i.e., how challenges may be resolved. Initial briefs are due within 30 days of publication in the Federal Register of notice of the Commission's instituting the proceeding, and reply briefs are due 21 days after the filing of initial briefs.

FERC approves PJM's Order No. 755 compliance filing, subject to conditions

E-4, *PJM Interconnection, L.L.C.*, Docket No. ER12-1204-000. The order addresses a compliance filing and proposed tariff revisions submitted by PJM in response to Order No. 755 (the Commission's rulemaking directive requiring

RTOs and ISOs to establish a two-part compensation methodology, including both a capacity-based payment and a performance-based payment for frequency regulation service). The order finds that PJM's compliance filing satisfies the requirements of Order No. 755, subject to conditions.

FERC rejects, without prejudice, application to terminate QF mandatory purchase obligation

E-7, *Public Service Company of New Mexico,* Docket Nos. QM12-2-000 and QM12-2-001. The order rejects, without prejudice to refiling as a new application, PNM's application to terminate its qualifying facility (QF) mandatory purchase obligation because PNM has not provided the required list of potentially-affected QFs.

FERC denies request for rehearing

E-9, *ISO New England, Inc.*, Docket No. ER11-4336-004. This order denies rehearing of the Commission's January 19, 2012 order accepting, with conditions, ISO-NE's two-stage Order No. 745 (the Commission's rulemaking directive on demand response compensation) compliance filing proposal, which included a transition period in which it would implement many of the changes necessary to comply with Order No. 745, and a later fully integrated solution which would be in full compliance with Order No. 745.

FERC denies request for rehearing

E-10, *CAlifornians for Renewable Energy, Inc., (CARE) and Barbara Durkin v. National Grid, Cape Wind and the Massachusetts Department of Public Utilities,* Docket No. EL11-9-001. This order denies CARE's request for rehearing of the Commission's November 7, 2011 order dismissing CARE's complaint against National Grid, Cape Wind, and the Massachusetts Department of Public Utilities.

FERC grants, in part, petition for declaratory order on participant funding of transmission lines

E-12, *National Grid Transmission Services Corporation and Bangor Hydro Electric Company (Northeast Energy Link)*, Docket No. EL11-49-000. The order grants National Grid Transmission Services Corporation's and Bangor Hydro Electric Company's (together, the Northeast Energy Link parties') petition for a declaratory order, but only on the limited issue of whether a generator's funding the construction of a high voltage direct current transmission line, in return for priority rights to the line's capacity, is consistent with the Commission's open access transmission requirements. The order explains that participant funding in

and of itself is not inconsistent with the Commission's open access transmission requirements.

FERC denies request for rehearing and clarification

H-1, *Wyco Power and Water, Inc.,* Project No. 14263-001. The order denies Wyco's request for rehearing and clarification of a February 2012 staff order dismissing its preliminary permit application for a proposed project that would include a new 501-mile-long water pipeline and seven hydropower developments to be located in Wyoming and Colorado.

FERC denies rehearing

H-3, *Borough of Weatherly, Pennsylvania,* Project No. 14358-001. The order denies the Borough of Weatherly, LLC's rehearing request of a previous staff order that dismissed as late-filed its competing preliminary permit application to study the feasibility of developing the hydroelectric power potential at the U.S. Army Corps of Engineers' Francis E. Walter Dam, located on the Lehigh River, in Luzerne County, Pennsylvania.

FERC approves, with certain modifications and conditions, non-project use of project lands and waters

H-5, *Public Utility District No. 1 of Chelan County, Washington,* Project No. 2145-109. The order authorizes the licensee, Public Utility District No. 1 of Chelan County, Washington, to permit Beebe Ranch, LLC to construct boat dock facilities within the project boundary. The marina facilities would be located on the Columbia River in Douglas County, Washington, and would consist of a 40-slip community boat dock and an access area to be used by the residents of the Beebe residential community. The order directs the licensee to include in Beebe Ranch's permit certain modifications and conditions.

FERC dismisses petition for declaratory order

H-6, *Public Utility District No. 2 of Grant County, Washington,* Project No. 2114-250. The order dismisses as premature a petition by Public Utility District No. 2 of Grant County, Washington for an order declaring that state and local regulation is preempted with respect to a fish protection facility that Grant County proposes to construct as mitigation for the impacts of its Priest Rapids Project, located on the Mid-Columbia River, in Washington. The order concludes that Grant County needs to file an amendment application seeking Commission authorization for the facility in question before the issue of preemption will be ripe.

FERC authorizes replacement facilities and increased natural gas storage deliverability

C-1, *Natural Gas Pipeline Company of America LLC*, Docket No. CP11-547-000. The order authorizes Natural's proposed 2012 Storage Optimization Project, which is designed to replace aging compressor units with new equipment, optimize Natural's market-area storage withdrawal and injection capabilities, and improve the flexibility and reliability of its Gulf Coast Mainline System. Specifically, the order authorizes Natural to construct and operate compression facilities in Washington County, Iowa and Effingham County, Illinois, and to abandon certain compression facilities in Clinton and Platt Counties, Illinois. The order also grants, as part of the proposed project, Natural's requests for authority to reduce the cushion gas inventory at its North Lansing Storage Field in Harrison County, Texas; increase the certificated peak day storage deliverability of its Keota St. Peter Reservoir in Washington County, Iowa; and increase the meter capacity at its Compressor Station 205. In addition, the order grants Natural's request for a pre-determination that it may roll the costs associated with the proposed facilities into its system rates in a future Natural Gas Act section 4 rate case, absent any significant change in circumstances, as the project will provide operational benefits to existing customers. No party filed a protest to Natural's application.

FERC authorizes project to install and operate new compressor units and related facilities at Elba Island LNG import terminal in GA

C-2, *Southern LNG Company, L.L.C.*, Docket No. CP12-31-000. The order authorizes Southern LNG to install and operate a new 2,500 horsepower electric motor-driven compressor and related facilities at the site of its existing liquefied natural gas (LNG) import terminal located at Elba Island near Savannah, Georgia to capture and compress natural gas that boils off from the LNG storage tanks and inject it into the downstream interstate pipelines.

June 21, 2012

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Docket Nos. RM12-6-000, RM12-7-000

FERC Proposes to Approve NERC's Revised Definition for Bulk Electric System

The Federal Energy Regulatory Commission (FERC) today issued a proposal that would approve the North American Electric Reliability Corporation's (NERC) revisions to the definition of the bulk electric system to provide greater clarity and ensure consistency in identifying system elements across the nation's reliability regions.

In response to a Commission directive, NERC in January 2012 filed revisions that:

- Establish a "core" definition that includes all transmission, real power and reactive power facilities operated or connected at 100 kilovolts or higher.
- Eliminate the discretion that Regional Entities now have to define the system in their region without any oversight from the Commission or NERC.
- Identify specific facility configurations that are included in or excluded from the definition.

Today's Notice of Proposed Rulemaking (NOPR) also proposes to approve NERC's new rules of procedure for adding elements to and removing them from the definition on a case-by-case basis. While proposing to approve the revisions to the definition of bulk electric system, the NOPR also seeks comment on certain issues, including the exclusion of certain facility configurations from the definition.

Comments on the NOPR are due 60 days after publication in the *Federal Register*.

R-12-23

(30)

June 2012
Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its June 21, 2012 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

E-2 – Press Release
E-3 – Press Release
E-4 – Press Release

FERC proposes revisions to process for filing Electric Quarterly Reports

E-1, *Revisions to Electric Quarterly Report Filing Process*, Docket No. RM12-3-000. The order proposes to change the process for filing Electric Quarterly Reports from one that requires downloading software from the Commission's website to one that allows filers to either file data through a web interface on the Commission's website or through an XML formatted file.

FERC denies rehearing on cost allocation to Merchant Transmission Facilities

E-5, *PJM Interconnection, L.L.C.*, Docket No. ER06-456-021, *et al*. The order denies requests for rehearing of Opinion No. 503, in which the Commission largely affirmed the Initial Decision's determination that PJM's proposal for allocating the costs of transmission upgrades approved as part of PJM's Regional Transmission Expansion Plan (RTEP) to Merchant Transmission Facilities with Firm Transmission Withdrawal Rights was just and reasonable, and not unduly discriminatory or preferential. The order reaffirms the analysis and conclusions of Opinion No. 503, explaining that Merchant Transmission Facilities with Firm Transmission Withdrawal Rights are unlike generation in that they take energy out of the system and their transmission needs must be planned for accordingly, and instead more closely resemble load and so should be allocated transmission costs as load is allocated transmission costs. As a result, such facilities may appropriately be assigned not only "but for" interconnection costs but also may appropriately be allocated transmission costs.

FERC accepts revisions to PJM tariff

E-6, *PJM Interconnection, L.L.C.*, Docket No. ER06-456-022, *et al*. The order accepts PJM's proposed revisions to the PJM Open Access Transmission Tariff to incorporate the methodology for assigning cost responsibility to Merchant Transmission Facilities with Firm Transmission Withdrawal Rights for transmission upgrades approved as part the PJM Regional Transmission Expansion Plan, as directed by Opinion No. 503, and reaffirmed in the companion order in E-5. The order also accepts PJM's refund report.

FERC denies rehearing, provides clarification of a Notice of Penalty order

E-8, *North American Electric Reliability Corporation*, Docket No. NP10-18-002. The order denies rehearing and provides clarification of the Commission's March 17, 2011, Order on Review of Notice of Penalty involving Turlock Irrigation District (Turlock). The March 17 order affirmed an $80,000 penalty that Western Electricity Coordinating Council assessed against Turlock for alleged violations of several Reliability Standards, including a violation of Reliability Standard FAC-003-1 Requirement R2 related to a vegetation-caused outage of transmission facilities on August 29, 2007. The order provides clarification on several issues related to notices of penalty, including load loss and self-reporting violations of Reliability Standards.

FERC denies rehearing

E-9, *Powerex Corp. v. United States Department of Energy, Western Area Power Administration – Sierra Nevada Region*, Docket No. EL12-21-001. This order denies Powerex's request for rehearing of an order issued on March 15, 2012, that denied a complaint filed by Powerex against the Western Area Power Administration – Sierra Nevada Region (Western), alleging that Western unlawfully and preferentially awarded transmission service to Morgan Stanley Capital Group Inc.

FERC grants, in part, and denies, in part, requests for relief

E-10, *Astoria Generating Co. L.P., et al. v. New York Independent System Operator, Inc.*, Docket No. EL11-42-000. The order grants, in part, and denies, in part, the relief requested in a complaint by Astoria Generating Company (Astoria) and others concerning New York Independent System Operator's (NYISO) implementation of buyer-side mitigation rules. The order finds that, with certain revisions (including not only certain tariff revisions but also disclosure that mitigation has occurred and the provision of an example of its mitigation methodology), NYISO's implementation is sufficiently transparent and objective, that an inflation adjustment should be consistently applied across all parts of the mitigation exemption test and offer floors, and also should be consistent with that used in determining the Installed Capacity Demand Curve. The order also requires NYISO to use values from the same demand curve that is effective at the time NYISO makes an exemption determination when NYISO compares a project's

Default net Cost of New Entry (CONE) with spot market auction prices. Other elements of the complaint (e.g., relating to NYISO review of bilateral contracts and use of natural gas futures prices in calculating Default net CONE) are denied.

FERC conditionally accepts an unexecuted service agreement

E-13, *Southwest Power Pool, Inc.*, Docket No. ER12-1600-000. The order conditionally accepts an unexecuted service agreement between Southwest Power Pool, Inc. (SPP) and Exelon Generation Company, LLC (Exelon), effective April 1, 2012, as requested by SPP, subject to modification to include proposed revisions necessary to reflect the rights of Exelon's 12 wind qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (e.g., the right to sell a QF's net output to the host utility). Without the revisions, Exelon's 12 wind QFs otherwise would be required by the service agreement to obtain transmission service and to participate in the Energy Imbalance Market or be subject to incurrence of credits and charges in that Market.

FERC rules off-system sales were permitted under System Agreement, but method for allocating energy for those sales violated System Agreement, thus requiring refunds

E-14, *Louisiana Public Service Commission v. Entergy Corporation, Entergy Services, Inc., Entergy Louisiana, L.L.C., Entergy Arkansas, Inc., Entergy Mississippi, Inc., Entergy New Orleans, Inc.*, Docket No. EL09-61-001. The order addresses exceptions to an Initial Decision issued on December 9, 2010, in which the Presiding Judge found that Entergy Corporation (Entergy) and its affiliates violated Entergy's Commission-approved generation and transmission pooling arrangement, the Entergy System Agreement (System Agreement), when affiliate Entergy Arkansas, Inc. sold excess electric energy to third-party power marketers and others that are not members of the System Agreement. The order affirms in part and reverses in part the Initial Decision and establishes further hearing procedures to determine refunds. The order finds that, although the sales at issue were permitted under the System Agreement, the method used to allocate energy for those sales violated the System Agreement, thus requiring refunds.

FERC denies request for clarification

E-20, *Interpretation of Protection System Reliability Standard*, Docket No. RM10-5-001. The order denies a request for clarification filed by National Rural Electric Cooperative Association (NRECA) in response to Order No. 758, which approved the North American Electric Reliability Corporation's (NERC) interpretation of mandatory Reliability Standard PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing). NRECA filed a motion for clarification of the characterization of NRECA's comments on reclosing relays. The order denies NRECA's request, explaining that the final rule accurately conveyed NRECA's comments.

FERC denies request for rehearing

E-27, *Puget Sound Energy, Inc.*, Docket No. EL10-72-001. This order denies Puget's request for rehearing of the Commission's November 18, 2010, order in this proceeding. The November 18 order rejected Puget's petition for a declaratory order that sought confirmation of firm priority rights on generator lead lines associated with a multi-phased wind generation project that Puget was planning to construct. The order finds that Puget's request for rehearing impermissibly raised materially different facts from facts that were presented in its petition.

FERC grants a request for a declaratory order

G-2, *Shell Pipeline Company LP*, Docket No. OR12-11-000. The order grants Shell's March 30, 2012, petition requesting that the Commission issue a declaratory order approving Shell's proposed contract rates, proposed service priority rights and prorationing provisions for shippers, and its use of a net present value methodology to allocate requests for contract capacity during its binding open season, for proposed transportation service from Houston, Texas to Houma, Louisiana and certain other destinations and origins.

FERC accepts filing, orders further revisions

G-3, *TransColorado Gas Transmission Company, LLC*, Docket No. RP12-245-000. The order accepts, with conditions, a filing by TransColorado to revise its reservation charge credits tariff provisions. The order requires TransColorado to make further revisions, including changes it had agreed to make in its answer to protests to its filing. The order also requires TransColorado to revise its definition of *force majeure*, since it may be overly broad, or explain why it need not make any change.

FERC denies rehearing

H-2, *Percheron Power, LLC*, Project No. 14208-001. The order denies rehearing of a Commission staff order that rejected Percheron's conduit exemption application for the Potholes East Project, proposed to be located on the Potholes East Canal at Station 1973, near Othello, Franklin County, Washington.

FERC denies rehearing

H-3, *PPL Montana, LLC*, Project No. 2188-201. The order denies rehearing of Commission staff's letter orders of February 1, 2011, and January 10, 2012, addressing concerns raised in numerous letters and at on-site meetings by an adjoining landowner, Mr. Thomas Andersen, regarding erosion along the shoreline of Lake Helena, part of the Missouri-Madison Project No. 2188. The project is located on the Madison and Missouri Rivers in Gallatin, Madison, Lewis and Clark, and Cascade Counties in southwestern

Montana. The order affirms staff's finding that project operations do not cause or contribute to ice movement along Lake Helena, which is a natural phenomenon. In addition, the order affirms that the project's approved erosion plan does not require PPL Montana to address shoreline erosion along Lake Helena. Finally, the order explains that PPL Montana has voluntarily taken actions to monitor and control shoreline erosion adjacent to Mr. Andersen's property in an effort to respond to his concerns.

FERC grants certificates and vacates certificate authorizations

C-1, *Caledonia Energy Partners, L.L.C.*, Docket No. CP12-33-000. This order grants authorization under the Natural Gas Act for the construction and operation of the Delta Pressure –DP33 Project that would modify Caldedonia's existing natural gas storage facility in Lowndes County, Mississippi. The order also vacates its certificate authorization for the County Line Expansion Project, and permits Caledonia to continue to charge market-based rates.

FERC approves abandonment and grants a certificate of public convenience and necessity

C-2, *Southern Natural Gas Company and High Point Gas Transmission, LLC,* Docket Nos. CP12-4-000 and CP12-9-000. This order approves Southern Natural Gas' request to abandon the South of Toca Facilities, which bring production volumes of natural gas from the Gulf of Mexico to onshore Louisiana, by sale to High Point Gas Transmission, LLC. This order also issues certificates to High Point Gas Transmission, LLC, to acquire and operate those segments of the South of Toca Facilities that function as jurisdictional transmission facilities.

FERC grants abandonment and grants a certificate of public convenience and necessity

C-3, *ANR Pipeline Company and TC Offshore, LLC*, Docket Nos. CP11-543-000 and CP11-544-000. The order authorizes ANR Pipeline Company's proposal to abandon by sale to its wholly owned subsidiary, TC Offshore LLC, all of its offshore pipeline facilities in the Gulf of Mexico and certain onshore pipeline facilities in Louisiana and Texas. The order also grants TC Offshore a certificate of public convenience and necessity to acquire and operate those facilities that will primarily function as jurisdictional transmission facilities.

FERC grants abandonment and grants a certificate of public convenience and necessity

C-4, *Trunkline Gas Company, LLC and Sea Robin Pipeline Company, LLC,* Docket No. CP12-5-000. The order grants Trunkline's request for approval of abandonment by sale to its affiliate, Sea Robin of Trunkline's facilities in the Gulf of Mexico, offshore

Louisiana and Texas, and certain associated onshore pipeline facilities in Louisiana. The order also grants Sea Robin's request for Natural Gas Act section 7(c) certificate authority to own and operate the facilities.

FERC grants abandonment authority

C-5, *Columbia Gulf Transmission Company and Texas Eastern Transmission, LP*, Docket No. CP11-13-000 and CP11-103-000. This order authorizes Columbia Gulf and Texas Eastern to abandon their obligations to provide transportation service using their ownership interests in two small discrete undersea pipelines located in the Gulf of Mexico, offshore Louisiana. One of the pipelines has previously been determined to perform a gathering function.

FERC terminates prior authorization as requested, and grants new authority for facilities to transport imported and exported gas between the US and Canada,

C-6, *Bluewater Gas Storage, LLC*, Docket No. CP12-5-000. This order terminates the Presidential Permit and Natural Gas Act (NGA) section 3 authorizations issued to Bluewater for the import and export of natural gas between the United States and Canada through facilities that Bluewater currently leases from Nova Chemicals, Inc. The order also issues a new Presidential Permit and NGA authorization for Bluewater's proposed St. Clair River Crossing Replacement Project. Bluewater would construct, operate and maintain its own new border crossing facilities at the United States/Canada international boundary in St. Clair County, Michigan, to transport the natural gas between the United States and Canada.

Federal Energy Regulatory Commission
June 21, 2012
Open Commission Meeting
Staff Presentation
Item A-3

"Mr. Chairman, Commissioners: I am pleased to present a summary of the FERC/NERC Staff Report on the October 2011 Northeast Snowstorm Outages.

As you know, this was a joint inquiry with the North American Electric Reliability Corporation. The team also included a Northeast Power Coordinating Council representative. We thank NERC and NPCC for their contributions to the inquiry. I would also like to recognize the team members from the Office of Electric Reliability who are not present: Justin Cunningham, Andrea Scott, and Norris Henderson.

The report is based on conclusions of staff and does not represent the views of the Commission, the Chairman, or any Commissioner.

During the course of the inquiry, the team issued detailed data requests to many utilities and other entities throughout the Northeast, made site visits to transmission facilities in New England, and interviewed representatives of a number of affected entities. The team also conducted numerous outreach meetings and calls with agencies in affected states and with electric industry trade associations

The purpose of the inquiry was to look into whether any FERC-jurisdictional facilities or NERC Reliability Standards were implicated in the power outages caused by the October 2011 snowstorm. Therefore, the inquiry focused on the storm's impacts to the transmission system. We did not examine the storm's impact on distribution systems, or make any recommendations relating to distribution facilities.

The snowstorm that hit the Northeastern United States on October 29-30, 2011 was an unprecedented Fall weather event, breaking records across the New England and Mid-Atlantic states. Up to two-and-a-half feet of heavy, wet snow fell on trees that had not yet lost their leaves and that were rooted in ground that had been saturated by an unusually warm, rainy summer. The weight of the snow, in combination with the soft ground, caused many healthy trees to become uprooted and fall on power lines. More than three million homes and businesses from Pennsylvania to Maine were without power as a result of the storm.

The majority of these outages were the result of damage to the distribution system. Only about 130,000 of the customer outages – less than 5% – were the result of transmission facility outages.

Inquiry staff identified 74 transmission line and 44 transmission substation outages that lasted 10 or more minutes. These outages occurred in six states: Connecticut, Massachusetts, Maine, New Hampshire, New York, and Rhode Island. These were mostly 115 kV lines, but there were one 138 kV and three 345 kV line outages.

Although this number of transmission facility outages constitutes a significant transmission event, the outages did not threaten the stability of the bulk power system.

These transmission outages were overwhelmingly caused by tree contact. Fifty-five of the 74 transmission line outages -- that is about 75% -- occurred when snow-laden trees or branches fell onto transmission lines. Most of these trees fell onto lines from outside the utilities' rights-of-way. But 13 transmission line outages resulted from trees falling from within a utility's right-of-way -- that is, the area the utility has the right to maintain, although in some cases those rights may be limited.

Because the vast majority of transmission outages were caused by tree contact, we evaluated the applicability of the Commission-approved transmission vegetation management reliability standard, FAC-003-1, to the event. We found that the standard had limited applicability here, mainly because the vast majority of impacted transmission lines were operated at 115 kV, and FAC-003-1 does not apply to any lines under 200 kV unless designated as critical to reliability by the owner or Regional Entity. In fact, FAC-003-1 applied to only one line damaged by tree contact during the storm, a 345 kV line in Connecticut.

As to recommendations, staff did see areas where utilities could take steps to improve transmission system reliability in future snowstorms or similar weather events. Therefore, the report makes several recommendations regarding utility best practices. The report's two key recommendations relate to vegetation management.

First, where appropriate, the report recommends that utilities take targeted steps to address off-right-of-way danger trees (that is, trees so tall and so close to facilities that, if they fell, would contact a transmission line). We recommend that utilities focus on identifying danger trees outside the rights-of-way of lines over 200 kV and other critical transmission lines and work with stakeholders to develop a strategy for addressing the danger trees that pose the greatest threat to bulk-power system reliability.

Second, where feasible, the report recommends that utilities employ the industry best practice of ensuring danger trees are not present inside their rights-of-way. We also recommend a targeted approach here: utilities should identify areas where elimination of danger trees inside the right-of-way is feasible and would increase reliability, and then prioritize their efforts on rights-of-way where critical facilities are located.

The report recognizes that vegetation management is often a sensitive issue and utilities should work cooperatively with landowners in implementing these recommendations.

We thank you for the opportunity to present this brief summary of the inquiry report."

Federal Energy Regulatory Commission
June 21, 2012
Open Commission Meeting
Staff Presentation
Item E-4

"Good morning Mr. Chairman and Commissioners,

Item E-4 is a draft Notice of Proposed Rulemaking that proposes to approve two filings submitted by the North American Electric Reliability Corporation. First, the NOPR proposes to approve NERC's modification to the currently-effective definition of "bulk electric system" contained in NERC's *Glossary of Terms Used in Reliability Standards*. Second, the NOPR proposes to approve NERC's related filing that would change the NERC Rules of Procedure to provide an "exception" process for adding elements to - and removing them from - the bulk electric system on a case-by-case basis.

In response to the Commission's directive in Order No. 743, NERC filed revisions to the definition of 'bulk electric system' that:

1. Establish a "core" definition that includes all transmission elements and real power and reactive power resources operated or connected at 100 kilovolts or higher; and,
2. Eliminate the discretion that Regional Entities now have to define the system in their region without any oversight from the Commission or NERC.

NERC's modified definition also identifies specific facility configurations that are included in or excluded from the bulk electric system.

The draft NOPR proposes to approve NERC's revised definition because it (1) responds to the Commission's concerns in Order No. 743, (2) removes regional discretion that is contained in the existing definition and (3) establishes a 100 kV bright-line threshold. The draft NOPR indicates that NERC's proposal offers additional clarity to the definition of 'bulk electric system' by creating specific, bright-line inclusions and exclusions within the definition, which also provide granularity with regard to common types of facilities and facility configurations to determine whether they are part of the bulk electric system.

While proposing to approve the revisions to the definition of bulk electric system, the draft NOPR also seeks comments on various provisions of NERC's proposal. In these questions, the NOPR seeks better understanding regarding the application of the bulk electric system definition to certain common facility configurations. By soliciting comment on these matters, we seek to provide a common understanding that will ensure a consistent application of the definition in indentifying bulk electric system facilities. While the NOPR does not propose to direct modifications to any provision of the proposal, it does note that responses to the questions in NOPR comments may highlight the need to modify a provision.

With regard to NERC's second filing, the draft NOPR proposes to approve NERC's changes to its Rules of Procedure which create an exception process for adding elements to and removing them from the definition on a case-by-case basis. The draft NOPR proposes to find that the exception process, under which NERC will make the final decision on whether to grant an exception request, better assures consistency of decisions across all regions and provides clarity and consistency across the nation's reliability regions in identifying bulk electric system facilities.

Further, the draft NOPR proposes that NERC file an informational filing within 90 days of the effective date of a final rule, detailing its plans to maintain a list of facilities that have received exceptions and how NERC will make this information available to the Commission, Regional Entities, and potentially to other interested persons.

Thank you. This concludes our presentation."

markets serving 19.2 million customers. NYISO manages a nearly 11,000-mile network of high-voltage transmission lines.

100. PJM is comprised of more than 700 members including power generators, transmission owners, electricity distributers, power marketers, and large industrial customers and serves 13 states and the District of Columbia.

101. SPP is comprised of 63 members serving 6.2 million households in nine states and has 48,930 miles of transmission lines.

102. MISO is a nonprofit organization with over 145,000 megawatts of installed generation. MISO has over 57,600 miles of transmission lines and serves 13 states and one Canadian province.

103. ISO–NE is a regional transmission organization serving six states in New England. The system is comprised of more than 8,000 miles of high-voltage transmission lines and over 300 generators.

104. The Commission certifies that this rule will not have a significant economic impact on a substantial number of small entities, and therefore no regulatory flexibility analysis is required.

VII. Document Availability

105. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

106. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

107. User assistance is available for eLibrary and the the Commission's Web site during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov*.

VIII. Effective Date and Congressional Notification

108. These regulations are effective July 6, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. In § 35.28, paragraphs (g)(4) through (g)(7) are redesignated as paragraphs (g)(5) through (g)(8) and a new paragraph (g)(4) is added to read as follows:

§ 35.28. Non-discriminatory open access transmission tariff.

* * * * *

(g) * * *

(4) *Electronic delivery of data.* Each Commission-approved regional transmission organization and independent system operator must electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the Commission, data related to the markets that the regional transmission organization or independent system operator administers.

* * * * *

Note: The following appendix will not be published in the Code of Federal Regulations.

Appendix A

Commenters on the NOPR

American Public Power Association (APPA)
California Department of Water Resources State Water Project (SWP)
Cogeneration Association of California and the Energy Producers and Users Coalition (CAC/EPUC)
Edison Electric Institute and the Electric Power Supply Association (EEI/EPSA)
ISO New England Inc. (ISO–NE)
ISO/RTO Council (IRC)
New York Public Service Commission (NYPSC)
Pennsylvania Public Utility Commission (PA PUC)
Powerex Corp. (Powerex)

[FR Doc. 2012–9847 Filed 5–4–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM11–18–000; Order No. 762]

Transmission Planning Reliability Standards

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL–002–0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process. The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest.

DATES: This rule will become effective July 6, 2012.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

• *Agency Web Site: http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

• *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Eugene Blick (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–8066, *Eugene.Blick@ferc.gov.*

Robert T. Stroh (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–8473, *Robert.Stroh@ferc.gov.*

SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,060

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

Final Rule

Issued April 19, 2012.

1. Under section 215(d) of the Federal Power Act,[1] the Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL–002–0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process.[2] The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. We require NERC to utilize its Expedited Reliability Standards Development Process to develop timely modifications to TPL–002–0b, Table 1 footnote 'b' in response to our remand.[3]

I. Background

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard TPL–002–0.[4] In addition, pursuant to section 215(d)(5) of the FPA, [5] the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards, including footnote 'b' of Reliability Standard TPL–002–0.[6]

A. Transmission Planning (TPL) Reliability Standards

3. Currently-effective Reliability Standard TPL–002–0b addresses Bulk-Power System planning and related transmission system performance for single element contingency conditions. Requirement R1 of TPL–002–0b requires that each planning authority and transmission planner ''demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the network can be operated to supply projected customer demands and projected firm transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I.'' [7] Table I identifies different categories of contingencies and allowable system impacts in the planning process. With regard to system impacts, Table I further provides that a Category B (single) contingency must not result in cascading outages, loss of demand or curtailed firm transfers, system instability or exceeded voltage or thermal limits. With regard to loss of demand, current footnote 'b' of Table 1 states:

> Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

B. Order No. 693 Directive

4. In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency.[8] The Commission directed the ERO to develop certain modifications, including a clarification of Table 1, footnote 'b.'

5. In a subsequent clarifying order, the Commission stated that it believed that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service would be acceptable in limited circumstances.[9] Specifically, the Commission stated that ''a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service at the fringes of various systems would be an acceptable approach.'' [10]

C. NERC Petition

6. On March 31, 2011, NERC filed a petition seeking approval of its proposal to revise and clarify footnote 'b' ''in regard to load loss following a single contingency.'' [11] NERC stated that it did not eliminate the ability of an entity to plan for the loss of non-consequential load in the event of a single contingency but drafted a footnote that, according to NERC, ''meets the Commission's directive while simultaneously meeting the needs of industry and respecting jurisdictional bounds.'' [12] NERC stated that its proposed footnote 'b' establishes the requirements for the limited circumstances when and how an entity can plan to interrupt Firm Demand for Category B contingencies. According to NERC, the provision allows for planned interruption of Firm Demand when ''subject to review in an open and transparent stakeholder process.'' [13] NERC's proposed footnote 'b' states:

> An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when

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[1] 16 U.S.C. 824o(d)(4) (2006).

[2] NERC filed a petition seeking approval of Table 1, footnote 'b' of four Reliability Standards: Transmission Planning: TPL–001–1—System Performance Under Normal (No Contingency) Conditions (Category A), TPL–002–1b—System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL–003–1a—System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL–004–1—System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). While footnote 'b' appears in all four of the above referenced TPL Reliability Standards, its relevance and practical applicability is limited to TPL–002–0a.

[3] NERC Rules of Procedure, Appendix 3A, Standard Processes Manual at 34 (effective January 31, 2012).

[4] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[5] 16 U.S.C. 824o(d)(5)(2006).

[6] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1797.

[7] Reliability Standard TPL–002–0a, Requirement R1.

[8] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794.

[9] *Mandatory Reliability Standards for the Bulk Power System,* 131 FERC ¶ 61,231, at P 21 (2010) (June 2010 Order).

[10] *Id.*

[11] NERC Petition at 10.

[12] *Id.*

[13] *Id.*

achieved through the appropriate redispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

7. NERC supplemented the filing on June 7, 2011, in response to a Commission deficiency letter. NERC explained that ''the approach proposed in footnote 'b' is equally efficient because many of the stakeholder processes that will be used in footnote 'b' planning decisions are already in place, as implemented by FERC in Order No. 890 and in state regulatory jurisdictions.'' [14] NERC also pointed to state public utility commission processes or processes existing in local jurisdictions that address transmission planning issues that could serve to provide a case-specific review of the planned interruption of Firm Demand. According to NERC, such processes would more likely engage the appropriate local-level decision-makers and policy-makers.

8. With respect to review and oversight by NERC and the Regional Entities, NERC submitted that an ERO-specific process would place the ERO in the position of managing and actively participating in a planning process, which conflicts with its role as the compliance monitor and enforcement authority. NERC also stated that neither the ERO nor the Regional Entities will review decisions regarding planned interruptions. Their role will be limited to reviewing whether the registered entity participated in a stakeholder process when planning to interrupt Firm Demand. NERC explained that Regional Entities will have oversight after-the-fact by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.'

9. Furthermore, NERC stated that an objective of the planning process should be to minimize the likelihood and magnitude of planned Firm Demand interruptions. NERC contended that, due to the wide variety of system configurations and regulatory compacts, it is not feasible for the ERO to develop a one-size-fits-all criterion for limiting the planned firm load interruptions for Category B events. According to NERC, the standards drafting team evaluated setting a certain magnitude of planned interruption of Firm Demand, but there was no analytical data to support a single value, and it would be viewed as arbitrary.

D. Notice of Proposed Rulemaking

10. On October 20, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR [15]) proposing to remand NERC's proposal to modify footnote 'b.' In the NOPR, the Commission stated that it believed that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single contingency. The Commission expressed concern that the procedural and substantive parameters of NERC's proposed stakeholder process are too undefined to provide assurances that the process will be effective in determining when it is appropriate to plan for interrupting Firm Demand, does not contain NERC-defined criteria on circumstances to determine when an exception for planned interruption of Firm Demand is permissible, and could result in inconsistent results in implementation. The NOPR stated that the proposed footnote effectively turns the processes into a reliability standards development process outside of NERC's existing procedures. Furthermore, the NOPR stated that regardless of the process used, the result could lead to inconsistent reliability requirements within and across reliability regions. While the Commission recognized that some variation among regions or entities is reasonable, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions.

11. The Commission proposed to provide further guidance on acceptable approaches to footnote 'b' and sought comment on certain options for revising footnote 'b', as well as other potential options to solve the concerns outlined in the NOPR. In response to the NOPR, comments were filed by seventeen interested parties.[16]

II. Discussion

12. For the reasons discussed below, the Commission concludes that NERC's proposed TPL–002–0b does not meet the Commission's Order No. 693 directives, nor is it an equally effective and efficient alternative. Further, the Commission finds that the proposal is vague, potentially unenforceable and may lack safeguards to produce consistent results. On this basis, the Commission remands the proposal to NERC as unjust, unreasonable, unduly discriminatory or preferential and not in the public interest. Below, the Commission also provides guidance on acceptable approaches to footnote 'b.'

13. The Commission adopts the proposed NOPR finding that the footnote 'b' process lacks adequate parameters. The Reliability Standard requires that, when planning to interrupt Firm Demand, the Firm Demand interruption must be ''subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.'' [17] Without meaningful substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities would be limited to a review to ensure only that a stakeholder process occurred. As NERC explained, Regional Entities' involvement is limited to after-the-fact oversight by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.' [18]

[14] NERC Data Response at 4.

[15] *Transmission Planning Reliability Standards*, Notice of Proposed Rulemaking, 76 FR 66229 (Oct. 20, 2011), FERC Stats. & Regs. ¶ 32,683 (2011).

[16] NERC, The Edison Electric Institute (EEI), American Public Power Association (APPA), National Association of Regulatory Utility Commissioners (NARUC), ITC Holdings Corp. (ITC), Manitoba Hydro, California Department of Water Resources State Water Project (California SWP) Hydro One Networks, Inc and the Ontario Independent Electricity System Operator (Hydro One and IESO), Duke Energy Corporation (Duke), New York State Public Service Commission (NYPSC), Bonneville Power Administration (BPA), Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (KCPL), Midwest Independent System Operator, Inc. (MISO), Public Utility District No. 1 of Snohomish County, Washington (Snohomish), Transmission Access Policy Study Group (TAPS), Powerex Corp. (Powerex), and Florida Reliability Coordinating Council (FRCC).

[17] NERC Petition at 10.

[18] NERC Data Response at 7–9.

14. Further, the NERC proposal leaves undefined the circumstances in which it is allowable to plan for Firm Demand to be interrupted in response to a Category B contingency. The Commission believes that proposed footnote 'b' could be used as a means to override the reliability objective and system performance requirements of the TPL Reliability Standard without any technical or other criteria specified to determine when planning to interrupt Firm Demand would be allowable, and without violating any of the requirements of the TPL Reliability Standard. The TPL Reliability Standard requires that a planner demonstrate through a valid assessment that the transmission system is planned and can be operated to supply projected Firm Demand at all demand levels over a range of forecasted system demands.[19] In addition, a planner must consider all single contingencies under Table 1, Category B and demonstrate system performance.[20] For single contingency events where system performance is not met, a planner must provide a written summary of its plans to achieve system performance including implementation schedules, in service dates of facilities and implementation lead times.[21]

15. However, if system performance is not met for any single contingency event(s) under NERC's proposed footnote 'b,' a planner could plan to interrupt some portion of Firm Demand to meet system performance requirements thereby overriding the performance requirements of the TPL Reliability Standard. For example, if a planner determines during its annual assessment that for a single bulk-power system transformer contingency other bulk-power system elements would exceed their thermal ratings, a planner would have authority under the standard to plan to interrupt Firm Demand to relieve the exceeded thermal ratings of the bulk-power system elements rather than planning the system to withstand such a single contingency and avoid shedding firm load as the performance requirements of the TPL Reliability Standard require. Therefore, without articulating some bounds on the use of the planned shedding of Firm Demand, there could be instances of multiple exceptions that could affect the robustness of the system. Further, contrary to commenters contentions, NERC's proposal, for example, has no provision to evaluate this cumulative effect of the individual decisions to shed firm.[22]

16. The Commission disagrees with commenters that NERC's proposed footnote 'b' will have no adverse impact on reliable planning of the bulk-power system because planning to shed Firm Demand is intended to ensure that single contingency events do not result in adverse impacts and intended to preserve bulk-power system reliability.[23] Table 1 of the TPL Reliability Standard identifies the system performance requirements or ''System Limits or Impacts'' that a planner must apply during its assessment of Category B, single contingency events.[24] Except in limited circumstances, if a planner determines that it must plan to interrupt Firm Demand so that it does not violate the Table 1 system performance requirements, a planner should not apply footnote 'b' as a mitigation plan to plan to operate reliably. The Commission therefore is concerned that NERC's proposal provides authority to adjust the TPL Reliability Standard and its system performance requirements for each single contingency event that does not meet the system performance requirements of Table 1.

17. Further, NERC has not provided technically sound means of determining situations in which planning to interrupt Firm Demand would be allowable. While NERC expects that such determinations will be made in a stakeholder process, this provides no assurance that such a process will use technically sound means of approving or denying exceptions. The Commission concludes that the multiple stakeholder processes across the country engaging in such determinations could lead to inconsistent and arbitrary exceptions including, potentially, allowing entities to plan to interrupt any amount of Firm Demand in any location and at any voltage level.

18. While the Commission recognizes that some variation among regions or entities is reasonable given varying grid topography and other considerations, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions. The Commission, thus, concludes that NERC's proposal lacks safeguards to ensure against inconsistent results and arbitrary determinations to allow for the planned interruption of Firm Demand.

19. A remand gives NERC and industry flexibility to develop an approach that would address the issues identified by the Commission with the proposed footnote 'b' stakeholder process including, as discussed below, definition of the process and criteria or guidelines for the process.

20. The Commission believes that, on remand, both NERC and the Commission will benefit from a more complete record regarding the electric industry's reliance on planned Firm Demand interruptions. In response to the Commission's request to explain and quantify the extent to which Firm Demand is planned to be interrupted pursuant to currently-effective footnote 'b,' NERC explained:

> NERC and the Regional Entities have not collected statistics or preformed a survey concerning the prospective implementation of Footnote b under TPL–002–0a. During the drafting team's deliberations concerning TPL–001–2 and TPL–002–0a Footnote b, including the NERC Technical Conference on Footnote b, the informal assessments demonstrated that the use of Footnote b would not be widespread.[25]

Likewise, several commenters state that the interruption of Firm Demand is rarely needed, but provide no support for this conclusion.[26] For example, EEI asks the Commission to ''recognize'' that ''* * * the actions taken as outcomes of the planning review process, are likely to identify few/isolated circumstances in which these [footnote b] provisions would be invoked* * *.'' [27] However, the Commission believes that more specific information regarding the specific circumstances and frequency with which Firm Demand is planned to be interrupted will assist both NERC in developing, and the Commission in reviewing, appropriate revisions to

[19] Reliability Standard TPL–002–0b, Requirement R1.

[20] Reliability Standard TPL–002–0b, Requirement R1.3.7.

[21] Reliability Standard TPL–002–0b, Requirement R2.

[22] BPA Comments at 5 (''The reasons for interrupting Firm Demand would be documented in studies and demonstrate that there would be no adverse impact to the BPS''); FRCC Comments at 3 (''Indeed, the transmission planning entity is responsible as part of the system assessment process under the TPL standards to test remedies to ensure that they address the problems being caused and do not cause additional problems.''); and Hydro One Comments at 5 (''Loss of load is under the purview of the regulatory authority and not NERC, unless it has an adverse impact on the BES which is already taken into consideration by the TPL standards * * * In all cases, steps are taken in planning, design and operations of the system to ensure that Firm Demand shedding would not adversely impact the BES * * *'').

[23] *See, e.g.,* NERC Comments at 11, TAPS Comments at 10, APPA Comments at 6.

[24] Reliability Standard TPL–002–0b, Table 1, Transmission System Standards—Normal and Emergency Conditions. Table 1 identifies the system performance requirements or ''System Limits or Impacts'' which are as follows: ''System Stable and both Thermal and Voltage Limits within Applicable Rating'', ''Loss of Demand or Curtailed Firm Transfers'' and ''Cascading Outages.''

[25] NERC Data Response at 10.

[26] *See, e.g.,* FRCC Comments at 4; MISO Comments at 4; BPA Comments.

[27] EEI Comments at 2.

footnote 'b' on remand. Therefore, pursuant to section 39.2(d) of the Commission's regulations,[28] we direct NERC to identify the specific instances of any planned interruptions of Firm Demand under footnote 'b' and how frequently the provision has been used. We direct NERC to use section 1600 of its Rules of Procedure to obtain information from users, owners and operators of the bulk-power system to provide this requested data.[29] NERC shall submit this information to the Commission with NERC's footnote 'b' filing that addresses the concerns in this Final Rule.

21. We urge NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule. In that regard, we require NERC to deploy its Expedited Reliability Standards Development Process to quickly respond to the remand. As the Commission noted in previous orders, the use of planned or controlled load interruption is a fundamental reliability issue and, certainty regarding the loss of non-consequential load for a single contingency event is warranted.[30] Thus, using the Expedited Standards Development Process will more rapidly bring needed certainty to this fundamental reliability issue.

22. Below we discuss three concerns: (a) Jurisdictional issues, (b) lack of technical criteria, and (c) the stakeholder process. The Commission also provides guidance on other acceptable approaches.

A. Jurisdictional Issues

23. A number of commenters express concern that the Commission is reaching beyond its FPA section 215 jurisdiction.[31] Commenters assert that the Commission options exceed its jurisdiction involving acceptable levels and types of service. Commenters seek assurance that the Commission's proposal does not infringe on matters reserved to the States and instead ''only prescribe acceptable load shedding as it pertains to wholesale customers that are in a position to select interruptible or conditional firm transmission service.'' [32] NARUC states that ''any NERC standard for shedding distribution level load must be guided by States and that a demonstration that interruption of the load will not cause instability, uncontrolled separation, or cascading failures on the bulk system is appropriate for a NERC standard.'' [33] NARUC adds that specifications of what retail load and what levels of retail load can be interrupted is a State determination that is not reviewable by the Commission. TAPS agrees with NERC that issues pertaining to whether it is permissible to plan to interrupt firm load involves conflicts among federal, provincial, state, and local governing bodies.[34]

24. The Commission disagrees that it is infringing on State Commissions or overstepping jurisdictional bounds. In this Final Rule, the Commission remands NERC's proposed footnote 'b' as an inadequate mechanism to address planned curtailment of firm demand and not responsive to the Commission's directives in Order No. 693 regarding this matter. The Commission is not directing that NERC develop a specific solution or approach on remand. Thus, our remand of the NERC proposed modification to TPL–002–0b, Table 1, footnote 'b' is fully within the Commission's authority pursuant to section 215(d)(4) to remand to the ERO for further consideration a modification to a proposed reliability standard that the Commission disapproves in whole or in part. Moreover, FPA section 215 gives the Commission jurisdiction over mandatory Reliability Standards to ensure reliability of the Bulk-Power System.[35] Consistent with its statutory authority, the Commission's interest and focus in this proceeding is on the planned interruption of Firm Demand on the Bulk-Power System. The Commission views this matter in the context of Reliability Standard TPL–002–0b, which requires that in planning the system to withstand the loss of a single Bulk-Power System element, Bulk-Power System performance criteria must be met. If it is not met, a corrective action plan is required to address the Bulk-Power System performance criteria violation. Contingencies studied pursuant to Reliability Standard TPL–002–0b pertinent to Bulk-Power System facilities are subject to Commission jurisdiction under FPA section 215. In sum, the performance of the Bulk-Power System under the TPL–002–0b Reliability Standard is within the Commission's jurisdiction.

B. Lack of Technical Criteria

NOPR Proposal

25. In the NOPR, the Commission proposed to remand NERC's proposal to modify Reliability Standard TPL–002–0b, Table 1, footnote 'b.' The Commission stated that it believed that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single contingency.[36] In the NOPR the Commission expressed concern that NERC's proposed footnote 'b' lacks parameters. Without any substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities would be limited to a review to ensure only that a stakeholder process occurred. The Commission noted that NERC appears to confirm this concern, as NERC explained that Regional Entities' involvement is limited to after-the-fact oversight by auditing the entity's implementation of footnote 'b' to determine if the planned interruption of Firm Demand was vetted through the stakeholder process.[37]

26. Further, in the NOPR the Commission stated that since the proposed footnote 'b' contains no constraints, it could allow an entity to plan to interrupt any amount of planned Firm Demand, in any location or at any voltage level as needed for any single contingency, provided that it is documented and subjected to a stakeholder process. The Commission found this result remains contrary to the underlying Reliability Standard and prior Commission orders.[38] The Commission requested comment on this specific concern of the lack of technical criteria or parameters.

Comments

27. Some commenters agree with the Commission that there is lack of technical criteria to determine planned interruption of Firm Demand. For example, California SWP states that Reliability Standards ''should ensure transparent criteria based on technical merits and not software limitations derived from a desire to mask [locational marginal pricing] price signals with socialized pricing or on *status quo* practices.'' [39] ITC believes that there is a need for defined parameters that will guide the review of exceptions and that will prevent

[28] 18 U.S.C. 39.2(d).

[29] NERC Rules of Procedure, Section 1601 (effective January 31, 2012).

[30] *North American Electric Reliability Corp.,* 130 FERC ¶ 61,200 (2010) (March 2010 Order); *North American Electric Reliability Corp.,* 131 FERC ¶ 61,231 (2010) (June 2010 Order).

[31] *See, e.g.,* Comments of NERC, NARUC, APPA and TAPS.

[32] NYPSC Comments at 5.

[33] NARUC Comments at 3–4.

[34] TAPS Comments at 9.

[35] 16 U.S.C. 824o(b)(1).

[36] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 11.

[37] *Id.* P 12.

[38] *Id.*

[39] California SWP Comments at 4.

planned interruptions from becoming commonplace.[40] Manitoba Hydro states that the characteristics of openness and transparency are indicators of a non-discriminatory planning process; however, these characteristics do not ensure that certain reliability criteria of the planned facilities will be met.[41]

28. Other commenters disagree with the Commission's concern that there is a lack of criteria to determine planned interruption of Firm Demand. NERC states that it does not believe that an exceptions process that provides defined criteria, with some allowances, could be crafted that would respect pre-existing decision making processes that occur at state and local jurisdictions. NERC argues that the decision to interrupt local load is essentially an economic decision—a quality of service issue, not a reliability issue.[42]

29. MISO disagrees that additional language would reduce the potential for inconsistent results and points out that registered entities already have many established requirements that govern the transmission planning processes.[43] MISO believes that if the Commission determines that criteria are needed, such criteria should be determined by the stakeholders in the regions though their established stakeholder processes.[44] EEI does not believe that specific criteria should be developed until a better understanding is obtained regarding the role of service interruptions as a reliability tool.[45] EEI believes that these are appropriate aspects of the NERC proposal that would be readily amenable to an initial implementation approach, followed by an adjustment period that would refine the overall process consistent with the Commission's concerns.

Commission Determination

30. We believe that openness and transparency do not alone ensure that bulk electric system performance criteria will be met to ensure system reliability. The Commission is not persuaded that developing technical criteria is unachievable. As the Commission observed in the NOPR, NERC has thresholds in other reliability contexts, such as vegetation management pursuant to Reliability Standard FAC–003–1 which applies to all transmission lines operated at 200 kV and above. Likewise, NERC's Statement of Compliance Registry Criteria includes numerous thresholds for determining eligibility for registration.[46]

31. The Commission does not agree with EEI's recommendation to implement a stakeholder process that is absent technical criteria but then amend it later. While the Commission has, in other circumstances, approved a Reliability Standard and, as a separate action, directed NERC to develop a modification pursuant to section 215(d)(5) of the FPA, in such proceedings the Commission concluded that the proposed Reliability Standard was just, reasonable, not unduly discriminatory or preferential and in the public interest. In the immediate proceeding, however, we cannot make such a finding in light of the flawed stakeholder process provision.

32. In response to MISO's argument that such criteria should be determined by the stakeholders in the regions though their established stakeholder processes, the Commission would be amenable to such an approach if, for example, NERC and/or the Regional Entities developed an exception process that provides flexibility in decisions based on disparate topology or on other matters since they could utilize their technical expertise to determine the reliability impact from one region to another. For these reasons, the Commission concludes that a more defined process is needed with NERC-defined technical criteria to determine planned interruption of Firm Demand. However, we conclude that the approach of allowing a decentralized process without any overarching parameters is unacceptable.

33. With regard to NERC's comment that the decision to interrupt local load is essentially an economic decision that is a quality of service issue, not a reliability issue, the Commission notes that in Order No. 693, we dismissed the argument that it may be preferable to plan the bulk electric system in such a manner that contemplates the interruption of some firm load customers in the event of a N–1 contingency, and that such interruption is based largely on the matter of economics, not reliability.[47]

C. Stakeholder Process

NOPR Proposal

34. In the NOPR, the Commission expressed concern that NERC's proposed footnote 'b' stakeholder process is insufficient to meet Order No. 693 and the June 2010 Order clarification that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm services at the fringes of the systems is acceptable in limited circumstances.[48] The Commission also noted that nothing in the proposed footnote 'b' defines the stakeholder process, other than that it must be an open and transparent stakeholder process that includes addressing stakeholder comments.[49] The Commission noted that any meeting that is open to stakeholders could meet this criteria.

35. The Commission further stated that the lack of a defined stakeholder process could allow a transmission planner to develop a process that provides insufficient opportunity for stakeholder participation and transparency yet still comply with the standard. The Commission expressed its belief that nothing in the proposed footnote 'b' restricts the stakeholder process, other than that it must be an open and transparent stakeholder process that includes addressing stakeholder comments. The Commission requested comment on whether a stakeholder process is the appropriate vehicle to approve or deny exceptions to allow entities to plan to interrupt Firm Demand for a single contingency and if so, whether the proposed footnote 'b' would require any stakeholder due process.

Comments

36. Several commenters believe that NERC's proposed stakeholder process is the appropriate venue to approve or deny exceptions to interrupt planned Firm Demand. NERC and other commenters contend that building on existing stakeholder processes is appropriate, rather than creating new, duplicative processes. While EEI, APPA, and TAPS concur with or acknowledge the Commission's concerns about the inadequacy of the proposed stakeholder process, they nonetheless urge the Commission to approve NERC's proposal stating that it reflects the considered expertise that instances of planned load shed are uncommon and not amenable to a one-size-fits-all approach.[50] NERC believes the introduction of an additional planning process may contribute to further delays and regulatory confusion. NERC states

[40] ITC Comments at 2.

[41] Manitoba Hydro Comments at 6.

[42] NERC Comments at 13.

[43] MISO Comments at 3.

[44] *Id.* at 5.

[45] EEI Comments at 10.

[46] *See, e.g.,* NERC Statement of Registry Criteria, section III. The Commission approved the Statement of Registry Criteria in Order No. 693. *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 95.

[47] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1792.

[48] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 19.

[49] *Id.* P 20.

[50] *See, e.g.,* EEI Comments at 3, TAPS Comments at 5, APPA Comments at 3.

that ''keeping decision-making with those most impacted by decisions regarding reliability and costs, lack of jurisdictional authority, and the existence of established open and transparent stakeholder processes—are the reasons NERC did not create a new stakeholder process.'' [51]

37. Duke Energy believes that the current Order No. 890-type process involving the local transmission planning collaborative is the appropriate stakeholder process. Duke Energy suggests that footnote 'b' should be revised to include a local regulatory authority process as the appropriate stakeholder process to allow entities to plan to interrupt Firm Demand for a single contingency. According to Duke Energy, in such a process a transmission planner would submit its plan to interrupt Firm Demand for a single contingency to its local regulatory authority that has jurisdiction over quality of service to local load prior to any actual interruption of Firm Demand.

38. BPA states that the stakeholder process will keep the decision local, where the parties involved understand the different factors that must be considered in deciding the proper path forward.[52] APPA maintains that these processes impose due process requirements on the transmission planner, including participation in an open and transparent stakeholder process that considers stakeholder comments.[53]

39. FRCC disagrees with the Commission that enforceability is limited since the process requires development of a record documenting the decisions and stakeholder comments and planning authority responses. According to FRCC, the result will provide NERC and the Commission substantive and procedural grounds to assess whether sufficient consideration was given to maintaining reliability.[54]

40. Some commenters believe that NERC's proposed stakeholder process is not the appropriate vehicle to approve or deny exceptions to interrupt planned Firm Demand. ITC argues that the stakeholder process is inadequately undefined to ensure that planned Firm Demand interruptions are kept to a minimum. Manitoba Hydro indicates that by acknowledging an exception for interruptible Firm Demand, NERC appears to recognize that the right to interrupt is not solely a reliability issue, but also a commercial or legal issue based on contractual rights.[55]

41. While TAPS encourages the Commission to accept NERC's proposed footnote 'b,' it shares the NOPR's concerns about the adequacy of the open and transparent stakeholder process and has argued for a decision-making role for transmission-dependent utilities in the Order No. 890 and Order No. 1000 planning processes to ensure that stakeholder processes do not result in a presentation of a decision followed by the transmission provider simply ''rubber-stamping'' the decision.[56] If the Commission determines that these objectives cannot be accomplished without more robust action from the Commission in this proceeding, TAPS urges the Commission not to remand the proposed footnote 'b,' but instead to accept NERC's proposal and direct NERC to submit a further modified footnote 'b' to address the parameters of the ''open and transparent stakeholder process that includes addressing stakeholder comments.'' [57]

Commission Determination

42. The Commission is not persuaded that the stakeholder process is adequately defined. The Commission is concerned that the stakeholder process could undermine the system performance criteria of TPL–002–0b Reliability Standard. As the Commission stated in Order No. 693, one of the key reliability objectives of the TPL Reliability Standard is that the system can be operated following the loss of one element and supply projected firm customer demands and projected firm transmission services at all demand levels over the range of forecast system demands.[58] The Commission finds that the stakeholder process without appropriate parameters is inconsistent with the reliability objective to supply projected firm customer demands for the loss of one element. While the Reliability Standard requires that the system is planned so that the system can be operated following the loss of one element and supply projected firm customer demands, the proposed stakeholder process could defeat this by allowing a transmission planner to plan to shed as much load as needed so that the system can be operated to supply whatever customers remain.

43. The Commission agrees with TAPS to the extent it observes that the proposal could allow a transmission planner to utilize a new or existing stakeholder process that provides insufficient opportunity for a stakeholder to provide meaningful input. We conclude that the stakeholder process with no criteria to objectively assess whether varied results are arbitrary or based on meaningful differences is unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. Nothing in proposed footnote 'b' defines the stakeholder process, other than it must be an open and transparent stakeholder process that includes addressing stakeholder comments.

44. The Commission is not persuaded by FRCC's comment that enforceability is not limited by proposed footnote 'b' and that development of a record will provide NERC ''substantive and procedural'' grounds to assess the outcome of the process. Neither FRCC nor any other commenter identifies the minimum procedural safeguards to assure an adequate level of stakeholder participation and consideration of stakeholder comment in the decision-making process. Moreover, even NERC, which states that it can conduct after-the-fact audits, indicates that such audits would not explore substantive adequacy or the reliability basis for a decision to plan to shed Firm Demand.[59] Further, the Commission is not persuaded by APPA and BPA comments that local stakeholder participation and due process requirements imposed on the transmission planner are sufficient. Rather, the Commission believes that if a transmission planner invokes a process that provides for minimal stakeholder involvement, it could argue that it satisfied the provision, even if the transmission planner is the ultimate decision maker and simply 'rubber stamps' its own proposal to interrupt planned Firm Demand.

D. Guidance on Acceptable Approaches to Footnote 'b'

45. The Commission proposed three options in the NOPR for further guidance on acceptable approaches to footnote 'b.' In addition, the Commission requested comment on other potential options to solve the concerns outlined in the NOPR.

1. Existing Protocols To Develop Criteria/Quantitative Limits

46. In the NOPR, the Commission acknowledged that NERC considered a variety of limits but observed that NERC's establishment of some form of

[51] NERC Comments at 12.

[52] BPA Comments at 4.

[53] APPA Comments at 5.

[54] FRCC Comments at 3.

[55] Manitoba Hydro Comments at 5.

[56] TAPS Comments at 5.

[57] *Id.* at 11.

[58] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1771.

[59] NERC Data Response at 7–9.

criteria for planning to interrupt Firm Demand could be an acceptable approach for footnote 'b.' The Commission requested comment on whether existing protocols such as the Department of Energy's Electric Emergency Incident and Disturbance Report (Form OE–417), which requires an entity to report a certain amount of uncontrolled loss of firm system loads, or NERC's Statement of Compliance Registry Criteria could provide guidance to NERC to devise criteria.

Comments

47. Commenters were unanimous that the examples of existing protocols would not be beneficial to devise criteria. NERC and others state that any bright-line megawatt limit would be inappropriate because the bright-line would be arbitrary.[60] Some commenters do not believe that existing protocols, such as the requirement in Form OE–417 should be used to determine criteria related to planned loss of Firm Demand.[61]

48. BPA, ITC, and Duke Energy comment that setting a quantitative limit would push transmission planners to plan to meet such a limit for a single contingency in all cases. Currently, transmission planners start from the premise that no load should be interrupted in the event of a single contingency. ITC believes that including such an acceptable lost load criterion as an option could lead to that option being chosen as the ''default solution,'' i.e., allowing for a certain amount of acceptable interruption of Firm Demand without a stakeholder exception review process.[62] In the same vein, Duke indicates that a specific megawatt threshold may prohibit certain interruptions of Firm Demand that would be acceptable from a quality of service and local consequences perspectives.[63]

Commission Determination

49. The Commission is persuaded by the commenters that Form OE–417 or the Registry Criteria are not, by themselves, beneficial to use to devise criteria. The Commission also agrees that a bright-line criteria by itself does not present a viable option and would have the potential to constitute an acceptable *de facto* interruption and become commonplace to plan to interrupt Firm Demand. For example, if the bright-line criteria included up to 50 MW of planned interruptible Firm Demand under proposed footnote 'b', then planners may choose to automatically shed up to 50 MW of load as their first course of action for any single contingency event that would cause a violation of system performance criteria. This is not an acceptable outcome.

2. A Blend of Quantitative and Qualitative Thresholds

50. The Commission also sought comment on whether a blend of quantitative and qualitative thresholds to be used to interrupt planned Firm Demand would be an appropriate option for providing criteria that would be generally applicable, but also for allowing for certain cases that may exceed the criteria. For example, a Reliability Standard could require a process with a quantitative limitation on how much Firm Demand could be planned for interruption and the standard could provide an exception process where a registered entity would submit documents and explanation to the ERO or a Regional Entity for approval based upon certain considerations.[64] The Commission suggested that setting generally applicable criteria for when an applicable entity can plan to shed Firm Demand, coupled with an exceptions process overseen by NERC and the Regional Entities, could mean that few exception requests must be processed by NERC and the Regional Entities.[65] The Commission observed in the NOPR that this approach may satisfy the need for technical criteria while accounting for NERC's concerns about the difficulty of developing a one-size-fits-all criterion for limiting planned Firm Demand interruptions and the appropriateness and feasibility of managing and actively participating in each planning process.

Comments

51. California SWP indicates that standards must constrain the use of firm load shedding as a reliability solution in transmission planning and at the same time, require a transparent and clearly defined stakeholder process to support any such planned use of load shedding for single contingency events.[66] BPA suggests that, if the Commission does set a quantitative limit on planned interruption of Firm Demand, a limit based on a fraction of aggregated normal peak load would be one option that may be more effective and adaptable to all sizes of utilities.[67]

52. Other commenters disagree that a blend is a good option. NARUC indicates that rather than inventing another stakeholder process by requiring NERC to set specific quantitative or qualitative requirements for distribution load shedding, NERC should look to State commissions and existing State curtailment plans to guide load shedding in contingency planning.[68] Duke Energy submits that a blend of quantitative and qualitative thresholds does not provide enough flexibility to permit the qualitative assessment of the loads and locations for which transmission planners may interrupt under their exercise of footnote 'b' because a blended threshold may still rely too heavily on a quantitative threshold for planned interruption of Firm Demand.[69] FRCC states it is not feasible to develop a single quantitative rule that would apply equitably to all stakeholders and regions.[70]

53. EEI believes that adopting a process that would provide greater clarity, reporting, and refinement would provide the specific information on the extent that the footnote 'b' issue presents itself. EEI also agrees with NERC that efforts to create a one-size-fits-all approach have less value than a process that ensures openness and transparency.

Commission Determination

54. The Commission believes that setting a quantitative and qualitative threshold in developing a limited exception for planned interruption of Firm Demand may be a workable solution. First, qualitative thresholds could be used to overcome the concern discussed immediately above regarding the quantitative threshold becoming an acceptable *de facto* interruption of planned Firm Demand. By utilizing a blend, the planner must also meet the qualitative threshold which could consist of, for example, the submittal of documents and explanation to the entity ultimately deciding whether the planned load shed is acceptable. For example, if 100 MW of planned Firm Demand was permitted to be interrupted, the planner could not automatically and unilaterally shed up to 100 MW of planned Firm Demand each time system performance criteria would be violated. Under the blend concept, the Commission envisions that

[60] NERC Comments at 14.

[61] ITC Comments at 5; *see also* Hydro One and IESO Comments.

[62] ITC Comments at 5.

[63] Duke Comments at 6.

[64] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 18.

[65] *Id.* P 27.

[66] California SWP Comments at 2.

[67] BPA Comments at 4.

[68] NARUC Comments at 3.

[69] Duke Energy Comments at 7.

[70] FRCC Comments at 7.

the planner would consider up to 100 MW of planned Firm Demand interruption along with other options to resolve the system performance criteria violation and submit its documentation and explanation to the entity deciding whether the planned load shed is acceptable. The concept of a blend of thresholds would prevent an acceptable *de facto* interruption of planned Firm Demand and avoid the difficulty of developing a one-size-fits-all criterion for limiting planned Firm Demand interruptions, but still allow for those limited circumstances to be reviewed in an exception process where a limited amount of planned interruption of Firm Demand may be acceptable.

55. We believe it is appropriate for the Regional Entities, with NERC as the final authority, to make determinations under a ''blended'' exception process. First, NERC and the Regional Entities provide both objectivity in the decision- making process as well as the necessary reliability-focused expertise. Second, this should not overly burden NERC or Regional Entity resources as utilization of the planned load shed exception is—and would be—rarely utilized.[71] Further, we are not persuaded by the assertion that NERC would be conflicted as the ERO and also inserting itself in the process. NERC's ERO role would continue, in coordination with its current responsibilities in implementing other exceptions such as the Technical Feasibility Exception process under the Critical Infrastructure Protection Reliability Standards.

56. The Commission does not agree with BPA's suggestion of using quantitative thresholds based on a fraction of aggregated normal peak load. BPA's suggestion attempts to address the concerns of commenters that a bright-line threshold must be established that would be a one-size-fits-all criteria. For example, instead of a megawatt bright-line threshold for all entities, the ERO could establish a threshold based on a percentage of aggregated normal peak load. The Commission believes that it would be difficult to demonstrate that adoption of BPA's suggestion would be just and reasonable, not unduly discriminatory or preferential and in the public interest. If criteria were established that permitted a percentage of aggregated normal peak load as an acceptable threshold for planned interruption of Firm Demand, even a small percentage could equate to entire towns, cities or regions of load.[72] The Commission, therefore, does not support the planned interruption of Firm Demand based on a fraction of aggregated normal peak load. The Commission believes that an appropriate mechanism would be based on impact studies that consider minimizing planned interruption of Firm Demand within, and adjacent to, communities and small localities.

57. The Commission offers guidance to NERC to consider the option of a blend of quantitative and qualitative thresholds. An example of a qualitative threshold could include identifying geographical or topological ''fringes of the system.'' While interruption at the fringes of the system may be expected by some consumers, not all customers necessarily have that same expectation. For example, we don't expect that many water treatment facilities or telecom switching stations normally plan to be interrupted for single contingency events.[73] While the Commission has offered one example of a qualitative threshold, NERC may explore other qualitative thresholds on remand. The Commission believes that a blend of quantitative and qualitative thresholds coupled with an exception process overseen by NERC and the Regional Entities would be a reasonable option to allow for the limited interruption of planned Firm Demand. Accordingly, the Commission directs the ERO to consider some blend of quantitative and qualitative thresholds.

3. Customer or Community Consent

58. In the NOPR the Commission also requested comment on whether a feasible option would be to revise footnote 'b' to allow for the planned interruption of Firm Demand in circumstances where the ''transmission planner can show that it has customer or community consent and there is no adverse impact to the Bulk-Power System.'' [74] The Commission suggested that this would not require affirmative consent by every individual retail customer, but would recognize that either group would need to be adequately defined. The Commission requested comments on who might be able to represent the customer or community in this option and how customer or community consent might be demonstrated.[75] The Commission also requested comment on how it would be determined that firm demand shedding with customer consent would not adversely impact the Bulk-Power System. Additionally, the Commission requested comment on whether a customer who would otherwise consent to having its planning authority or transmission planner plan to interrupt Firm Demand pursuant to this option could instead select interruptible or conditional firm service under the tariff to address cost concerns.

Comments

59. Several commenters agreed with the Commission that the customer or community consent should be required. ITC believes the customers or entities should be involved in a stakeholder process such as a representative group for the affected load or customers (community representatives or a separate load serving entity where the transmission provider is not an integrated utility), the public service/utility regulatory commission for the affected load, the RTO or ISO for the affected area, and any other affected entity. California SWP also supports notice to and consent of loads (or their wholesale representatives) that are planned to be interrupted for the loss of a single element.[76] In its comments, California SWP explains that it was ''surprised to learn that in lieu of transmission upgrades, [its transmission planner] relied on interruption of SWP's large firm pump loads supposedly receiving the same California Independent System Operator (CAISO) transmission service as provided to SCE loads. At that time, SWP was not consulted about the planned curtailment of its firm loads as an alternative to a transmission upgrade, and thus had no opportunity to correct this error.'' [77]

60. Other commenters disagree that customer or community consent should be required. NERC states that it has no relationship with retail customers and, therefore, has no mechanism to bring retail customers into the conversation. NERC adds that both wholesale and retail customers are already involved in state processes which provide a forum for them to be heard.

61. Hydro One and the IESO submit that customer interests are managed by the relevant regulatory authority and consent is through regulatory approval. In all cases, steps are taken in planning, design, and operations of the system to

[71] *See, e.g.,* FRCC Comments at 4; MISO Comments at 4; BPA Comments.

[72] For example, the PJM aggregated normal system peak load is approaching 160,000 MW, so a one percent threshold would equate to allowance of planned interruption for a single contingency of up to 1600 MW of load, which is the size of some entire towns, cities or regions.

[73] While we anticipate that such facilities are prepared for distribution-level blackouts, we are not aware that they are prepared for a transmission-level blackout.

[74] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 28.

[75] *Id.*

[76] California SWP Comments at 4.

[77] *Id.* at 2–3.

ensure that Firm Demand shedding would not adversely impact the bulk electric system in addition to the fact that the customer also has other options such as to select interruptible service. NYPSC recommends that the Commission only prescribe acceptable load shedding as it pertains to wholesale customers that are in a position to select interruptible or conditional firm transmission service under Commission-approved tariffs.

62. FRCC states that the evaluation of the possible use of interruptible or conditional firm service instead of planned interruptions of Firm Demand is not warranted. According to FRCC, the adoption of a Firm Demand interruption alternative would inherently entail customer benefits from foregone project costs and the non-incurrence of environmental and other impacts. The customers would also generally enjoy a higher quality of service than traditional interruptible or conditional firm. Consequently, FRCC believes that applying any such rate in place of Demand interruption would present imponderable issues of quantification and application.

63. BPA does not believe that this proceeding is appropriate to decide issues related to service choice. BPA argues that the Commission has determined that the rate for conditional firm service be the same as the firm rate. BPA does not anticipate that the interruption of Firm Demand would occur on a frequent basis, if at all. Thus, BPA does not believe that a customer should pay a different transmission rate under these circumstances. APPA states that footnote 'b' arms wholesale transmission customers and communities served at retail with information and studies prepared by the transmission planner, documenting the specific circumstances (i.e., specific Bulk Electric System Contingency events) under which interruption of Firm Demand may be needed to address bulk electric system performance requirements.

Commission Determination

64. We understand NERC's position that as the entity that addresses Bulk-Power System reliability, it does not have a mechanism to coordinate with customers. Likewise, how to define customers and community decisions and engage them in the NERC process could be challenging.[78]

65. At the same time, California SWP provides a compelling example of how a customer can be adversely affected by planned load shedding for Firm Demand if it was unaware its load would be interrupted until its load was actually shed. In contrast to California SWP's experience, a customer should have notice and understanding that the transmission planner plans to curtail certain Firm Demand in the event of a single contingency indentified in the system modeling under NERC's Transmission Planning requirements. NERC should consider these matters on remand.[79]

Summary

66. In sum, the Commission remands the proposed footnote 'b' and directs NERC to revise its proposal to address the Commission's concerns described above, subject to consideration of the additional guidance provided in this Final Rule.

67. As stated in the NOPR, NERC will need to support the revision to footnote 'b.' If there is a threshold component to the revised footnote, NERC would need to support the threshold and show that instability, uncontrolled separation, or cascading failures of the system will not occur as a result of planning to shed Firm Demand up to the threshold. In addition, if there is an individual exception option, the applicable entities should be required to find that there is no adverse impact to the Bulk-Power System from the exception and that it is considered in wide-area coordination and operations. Further, the Commission believes that any exception should be subject to further review by the Regional Entity or NERC.

III. Information Collection Statement

68. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[80] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[81]

69. As stated above, the subject of this Final Rule is NERC's proposed modification to Table 1, footnote 'b' applicable in four TPL Reliability Standards. This Final Rule remands the footnote 'b' modification to NERC. By remanding footnote 'b' the applicable Reliability Standards and any information collection requirements are unchanged. Therefore, the Commission will submit this Final Rule to OMB for informational purposes only.

70. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *data.clearance@ferc.gov*, phone: (202) 502–8663, or fax: (202) 273–0873].

IV. Environmental Analysis

71. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[82] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[83] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

72. The Regulatory Flexibility Act of 1980 (RFA) [84] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[85] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[86] The RFA is not implicated by this Final Rule because the Commission is remanding

[78] As suggested in the NOPR, customer or community consent would not require affirmative consent by every individual retail customer, but the process NERC developed would recognize that either group would need to be adequately defined. We note that, although NERC comments that it addresses Bulk-Power System reliability, the process that NERC proposes will impact firm load service to retail customers.

[79] We will not consider the tariff-related comments as they are beyond the scope of this rulemaking.

[80] 5 CFR 1320.11.

[81] 44 U.S.C. 3507(d).

[82] *Regulations Implementing the National Environmental Policy Act of* 1969, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[83] 18 CFR 380.4(a)(2)(ii).

[84] 5 U.S.C. 601–612.

[85] 13 CFR 121.201.

[86] *Id.* n.22.

footnote 'b' and not proposing any modifications to the existing burden or reporting requirements. With no changes to the Reliability Standards as approved, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

VI. Document Availability

73. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page *(http://www.ferc.gov)* and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington DC 20426.

74. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

75. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov*.

VII. Effective Date and Congressional Notification

76. These regulations are effective July 6, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By direction of the Commission. Commissioner Norris is dissenting in part and concurring in part with a separate statement attached.

Kimberly D. Bose,

Secretary.

NORRIS, Commissioner, *dissenting in part and concurring in part:*

The continued implementation and evolution of the mandatory reliability standards program enacted by Congress in 2005 has been at the forefront of our agenda since I arrived at the Commission in 2010. As we have grappled with the difficult issues raised by proposed new or revised standards, and as I have discussed these issues with regulated industry, state regulators, and the public, I have consistently heard a common theme: mandatory reliability standards come with costs that consumers ultimately must bear.

As I have thought about this issue, it has become clear to me that in any discussion of a new or revised mandatory reliability standard, there is always a tradeoff between the level of reliability to be achieved by that standard and the costs that the standard will impose. However, that tradeoff is rarely discussed explicitly in the standards development process or during the Commission's review of standards. But, we know that it is an implicit consideration of entities participating in the standards development process. I believe it is more appropriate to make those considerations, where they are relevant, explicit. Therefore, I have advocated for an open dialogue between NERC, the industry, and the Commission to consider the connection between the mandatory standards we approve to maintain and improve the reliability of the Bulk Power System and the costs required to meet those standards.

However, I have perceived some hesitancy in openly addressing costs when considering reliability matters. This is not surprising, as there are no easy answers to these tough questions, and regulators and industry charged with assuring reliability will always be hesitant to be perceived as sacrificing reliability in an effort to save on costs. While I am not advocating for a cost-benefit threshold for approving reliability standards, I do not believe that we can ignore the costs of proposed mandatory reliability standards as we consider whether they are ''just, reasonable, not unduly discriminatory or preferential, and in the public interest''.[1] These are issues with real world implications, not just for the reliability and security of our Nation's electric grid, but for the day-to-day struggles of local communities to balance the economic realities of many competing obligations.

I am compelled to raise these issues in this proceeding because I believe that the Transmission Planning (TPL) Reliability Standard footnote 'b' addressed in today's order presents a stark example of the tradeoffs that sometimes must be made between increasing levels of reliability and the costs that come with achieving them. As such, I hope my comments today will help generate a dialogue on how economics and reliability fit together when considering mandatory reliability standards.

In today's order, I agree with the majority's decision to remand proposed TPL footnote 'b' because it is vague, potentially unenforceable, and lacks adequate safeguards to determine when planning to shed firm load would be permitted. However, I am concerned that, in allowing for an exception to the TPL standards requirement that firm load must be maintained under N–1 scenarios, the order does not sufficiently recognize that this is both an economic and reliability issue, and must allow for a balancing of the economic and reliability considerations involved.

There may be cases where planning to avoid shedding firm load in all N–1 scenarios will impose significant costs on customers, with perhaps little added reliability benefit for those customers. In such instances, I believe that wholesale transmission customers and local communities with retail load service should be empowered to consider the economic tradeoffs between incurring costs to avoid shedding firm load versus planning to shed firm load, as long as that decision does not adversely impact the reliability of the Bulk Power System. Simply put, if a customer seeks to avoid significant costs, and can do so without impacting its neighbors, the customer should be making that decision. Today's order fails to adequately acknowledge the economic consequences of having to invest in significant facility upgrades to avoid shedding firm load under certain N–1 scenarios that may be rare or unlikely and that would have only local impacts.[2]

Accordingly, in my view, the Commission should have directed NERC to revise footnote 'b' to address two broad concerns. First, wholesale transmission customers and retail load should have the ability to choose whether to shed firm load during an N–1 contingency where that decision will not adversely impact the Bulk Power System. Second, the decision to shed firm load must be validated to ensure that there is no adverse impact on the Bulk Power System. Absent this reliability check, the planning of firm load shedding should not be permitted, because reliability of the Bulk Power System is paramount. While NERC, the Regional Entity, and/or the local planning authority must be involved in the reliability check, these entities would not be expected to be involved in the economic decision.

Additionally, I agree with various comments filed in response to the NOPR that firm load shedding is and should be used rarely or infrequently. I do not expect that any new process that NERC may propose to determine whether firm load shedding is permitted would result in a rush by entities seeking to plan to shed firm load. In other words, I do not expect this exception to ''swallow the rule'' under the TPL standards that firm load may not be planned to be shed for N–1 contingencies.

Finally, the concerns I note above regarding the failure to consider both the economic and reliability aspects of a decision to plan to shed firm load extend to the specific guidance provided in the order. The guidance in the order with respect to what

[1] *See* 16 U.S.C. 824o(d)(2).

[2] *Transmission Planning Reliability Standards*, Order No. 762, 139 FERC ¶ 61,060, at P 33 (2012) (''With regard to NERC's comment that the decision to interrupt local load is essentially an economic decision that is a quality of service issue, not a reliability issue, the Commission notes that in Order No. 693, we dismissed the argument that * * * such interruption is based largely on the matter of economics, not reliability.'') I also note that the brief Commission findings in Order No. 693 failed to acknowledge or sufficiently address this issue, leaving the uncertainty we are still faced with today. *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1791–1794 (2007).

would constitute an allowable exception fails to provide a realistic means for entities to balance these economic and reliability considerations. Instead, I would have provided that an entity could submit its plan to shed firm load for a single contingency to its relevant regulatory authority or governing body prior to any actual interruption.[3] The politically accountable regulatory authority or governing body would have then made the determination, based upon economics and in the best interests of its customers, as to whether firm load shedding should be permitted. Those determinations would be subject to oversight and review by NERC, the Regional Entity, and/or the planning authority to ensure that they will not adversely impact the Bulk Power System.[4]

For these reasons, I respectfully dissent in part and concur in part.

John R. Norris,

Commissioner.

[FR Doc. 2012–10944 Filed 5–4–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Parts 510 and 522

[Docket No. FDA–2012–N–0002]

New Animal Drugs; Change of Sponsor; Change of Sponsor Address; Change of Sponsor Name and Address; Fomepizole

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect a change of sponsor name from Bioniche Teoranta to Mylan Institutional, LLC; a change of sponsor for fomepizole injectable solution from Synerx Pharma, LLC, to Mylan Institutional, LLC; and a change of sponsor address for Modern Veterinary Therapeutics, LLC.

DATES: This rule is effective May 7, 2012.

FOR FURTHER INFORMATION CONTACT: Steven D. Vaughn, Center for Veterinary Medicine (HFV–100), Food and Drug Administration, 7520 Standish Pl., Rockville, MD 20855, 240–276–8300, email: *steven.vaughn@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: Bioniche Teoranta, Inverin, County Galway, Ireland, has informed FDA that it has changed its name and address to Mylan Institutional, LLC, 4901 Hiawatha Dr., Rockford, IL 61103. Synerx Pharma, LLC, 100 N. State St., Newton, PA 18940, has informed FDA that it has transferred ownership of, and all rights and interest in, abbreviated new animal drug application (ANADA) 200–472 for Fomepizole for Injection to Mylan Institutional, LLC. Modern Veterinary Therapeutics, LLC, 1550 Madruga Ave., suite 329, Coral Gables, FL 33146, has informed FDA that it has changed its address to 18001 Old Cutler Rd., suite 317, Miami, FL 33157. Accordingly, the Agency is amending the regulations in parts 510 and 522 (21 CFR parts 510 and 522) to reflect these changes.

Following this change of sponsorship, Synerx Pharma, LLC, is no longer the sponsor of an approved application. Accordingly, § 510.600 (21 CFR 510.600) is being amended to remove the entries for this firm.

This rule does not meet the definition of ''rule'' in 5 U.S.C. 804(3)(A) because it is a rule of ''particular applicability.'' Therefore, it is not subject to the congressional review requirements in 5 U.S.C. 801–808.

List of Subjects

21 CFR Part 510

Administrative practice and procedure, Animal drugs, Labeling, Reporting and recordkeeping requirements.

21 CFR Part 522

Animal drugs.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR parts 510 and 522 are amended as follows:

PART 510—NEW ANIMAL DRUGS

■ 1. The authority citation for 21 CFR part 510 continues to read as follows:

Authority: 21 U.S.C. 321, 331, 351, 352, 353, 360b, 371, 379e.

■ 2. In § 510.600, in the table in paragraph (c)(1), remove the entries for ''Bioniche Teoranta'' and ''Synerx Pharma, LLC''; revise the entry for ''Modern Veterinary Therapeutics, LLC''; and alphabetically add a new entry for ''Mylan Institutional, LLC''; and in the table in paragraph (c)(2), remove the entry for ''068882'' and revise the entries for ''015914'' and ''063286'' to read as follows:

§ 510.600 Names, addresses, and drug labeler codes of sponsors of approved applications.

* * * * *

(c) * * *

(1) * * *

Firm name and address	Drug labeler code
* * * * *	
Modern Veterinary Therapeutics, LLC, 18001 Old Cutler Rd., suite 317, Miami, FL 33157	015914
* * * * *	
Mylan Institutional LLC, 4901 Hiawatha Dr., Rockford, IL 61103 ..	063286
* * * * *	

(2) * * *

Drug labeler code	Firm name and address
* * * * *	
015914	Modern Veterinary Therapeutics, LLC, 18001 Old Cutler Rd., suite 317, Miami, FL 33157.
* * * * *	
063286	Mylan Institutional, LLC, 4901 Hiawatha Dr., Rockford, IL 61103.
* * * * *	

PART 522—IMPLANTATION OR INJECTABLE DOSAGE FORM NEW ANIMAL DRUGS

■ 3. The authority citation for 21 CFR part 522 continues to read as follows:

Authority: 21 U.S.C. 360b.

■ 4. In § 522.1004, revise paragraph (b) to read as follows:

§ 522.1004 Fomepizole.

* * * * *

(b) *Sponsors.* See Nos. 046129 and 063286 in § 510.600(c) of this chapter.

* * * * *

Dated: April 30, 2012.

Steven D. Vaughn,

Director, Office of New Animal Drug Evaluation, Center for Veterinary Medicine.

[FR Doc. 2012–10892 Filed 5–4–12; 8:45 am]

BILLING CODE 4164–01–P

[3] *See e.g.,* Duke Energy Corporation Dec. 22, 2011 Comments, Docket No. RM11–18–000.

[4] NERC may propose an alternative to Commission guidance that is equally efficient and effective at addressing the Commission's reliability concerns. Order No. 693 at P 31.

June 21, 2012

Chairman Jon Wellinghoff

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Statement of Chairman Jon Wellinghoff on Regional Conferences on Gas-Electric Coordination

"I am pleased to announce that the Commission is planning as many as five regional technical conferences to explore coordination between the natural gas and electric industries. These conferences, which are tentatively scheduled to cover the Midwest, the West, New England, New York, the mid-Atlantic and the Southeast, will each include a staff presentation on infrastructure in that region and an opportunity for a staff-led industry discussion of national issues affecting coordination between the gas and electricity markets, electric reliability, and those issues of special significance to that particular region. My colleagues and I look forward to attending these conferences as our schedules permit.

Details are still being worked out on dates and locations for each of these conferences, but we plan to hold them in July and August, with some conferences to be held here at the Commission headquarters and some to be held in regional centers.

We look forward to a productive discussion that will allow us to identify and move forward on steps both industries and regulators can take to improve coordination between these two, critically important industries."

FERC Order 763 (UFLS- PRC-006-01 and EOP-003-02) Issued May 7, 2012

Highlights

Background….P 4- The Commission neither approved nor remanded NERC-approved Reliability Standard PRC-006-0 in Order No. 693,which required regional reliability organizations to develop, coordinate, document and assess UFLS program design and effectiveness at least every five years.

P 25 (inaccuracies of modeling in UFLS) "the Commission will not issue a directive requiring the modeling of qualifying generation not directly connected to the bulk electric system."

P 29 (regarding inaccuracies of system modeling) "the Commission believes that the design requirements in Reliability Standard PRC-006-1 are acceptable."

P 36 (regarding system frequency excursions fall below the initializing set points for UFLS programs) "..we agree with NERC that underfrequency events that result in the initializing of the UFLS set point, even in the absence of island formation, would be analyzed under provisions contained in the NERC Rules of Procedure and the NERC Event Analysis program".

P 41 "The Commission is persuaded by the comments of NERC, MISO, and EEI that differences between planning coordinator event assessments should not be referred to reliability coordinators for resolution…If the Commission finds that these disputes are not being resolved, the Commission may consider adoption of an appropriate process to ensure resolution of the disputes."

DIRECTIVE, P 48 (Timeframe for entity implementation of a correction identified from a PC UFLS event assessment) ".. we direct NERC to make that requirement (R9) explicit in future versions of the Reliability Standard. Within 30 days of the effective date of this Final Rule, NERC is directed to submit a compliance filing indicating how it plans to comply with this directive and a deadline for compliance."

P 58 (Generator Trip Points outside the UFLS Program) "We are persuaded by NERC's comments that it is appropriate for planning coordinators to consider generators that trip outside of the UFLS set points when designing UFLS programs, but it is inappropriate for planning coordinators to determine whether mitigation is necessary and who will be responsible for providing mitigation. For these reasons, we take no action to modify the Reliability Standard.

P 64 (UFLS Coordination with other Protection Systems) "The Commission believes that this level of coordination between UFLS programs and other specific protection systems is adequate."

P 71 EPSA and PSEG stated need for interconnection wide UFLS standards not region wide ones. Commission responded –"..no Regional Reliability Standards currently before us in this matter and, therefore, the matter is not ripe for us to address."

P 73 (..“mutual consent” to adjust island boundaries from Regional Entity boundaries) “The Commission accepts NERC’s clarification of the level of consent required between planning coordinators to adjust island boundaries..”

P 80 (lack of Coordination between Auto UFLS and Manual UFLS) “..we find that there is an adequate level of coordination between UFLS and manual load shedding”

Implementation Plan and Effective Date - “..effective date for Reliability Standards PRC-006-1 and EOP-003-2 of one year following the first day of the first calendar quarter after applicable regulatory approvals with respect to all Requirements of the proposed Reliability Standards *except* Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1. With respect to Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1, NERC requests an effective date of one year following the receipt of generation data as required in Reliability Standard PRC-024-1,**59** but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.”….. “The Commission approves the implementation plan and effective dates of Reliability Standards PRC-006-1 and EOP-003-2.”

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139 FERC ¶ 61,098
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM11-20-000; Order No. 763]

Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards

(Issued May 7, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule

SUMMARY: Under section 215 of the Federal Power Act (FPA), the Federal Energy Regulatory Commission (Commission) approves Reliability Standards PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans), developed and submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Commission. In addition, pursuant to section 215(d)(5) of the FPA, the Commission directs NERC to develop a modification to clarify the intent of one provision of the Reliability Standard. The approved Reliability Standards establish design and documentation requirements for automatic underfrequency load shedding programs that arrest declining frequency and assist recovery of frequency following system events leading to frequency degradation. The Commission approves, with modifications, the related Violation Risk Factors and Violation Severity Levels, implementation plan, and

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effective date proposed by NERC. The Commission also approves the regional variance for the Western Electricity Coordinating Council in Reliability Standard PRC-006-1.

EFFECTIVE DATE: This rule will become effective **[60 days after publication in the FEDERAL REGISTER].**

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

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139 FERC ¶ 61,098
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,

Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards — Docket No. RM11-20-000

ORDER NO. 763

FINAL RULE

(Issued May 7, 2012)

1. Under section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standards PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans). In addition, pursuant to section 215(d)(5) of the FPA, the Commission directs the North American Electric Reliability Corporation (NERC) to develop a modification to clarify the intent of one provision of the Reliability Standard. The approved Reliability Standards were developed and submitted for approval to the Commission by NERC, the Commission certified Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. The approved Reliability Standards establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs, which are

[1] 16 U.S.C. 824o (2006).

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meant to arrest declining frequency and assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

2. The Commission approves, with modifications, the related Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), implementation plan, and effective date proposed by NERC. The Commission approves the retirement of the currently-effective Reliability Standards PRC-007-0, PRC-009-0, and EOP-003-1, and the NERC-approved Reliability Standard PRC-006-0. Further, the Commission approves the regional variance for the Western Electricity Coordinating Council (WECC) in PRC-006-1.

I. Background

A. Mandatory Reliability Standards

3. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[2]

4. Pursuant to section 215 of the FPA, the Commission established a process to select

[2] 16 U.S.C. 824o(e).

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and certify an ERO[3] and, subsequently, certified NERC as the ERO.[4] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standards PRC-007-0, PRC-009-0, and EOP-003-1.[5] The Commission neither approved nor remanded NERC-approved Reliability Standard PRC-006-0 in Order No. 693,[6] which required regional reliability organizations to develop, coordinate, document and assess UFLS program design and effectiveness at least every five years. The Commission determined neither to approve nor remand this "fill-in-the-blank" Reliability Standard because the regional procedures had not been submitted, and the Commission held that it would not propose to approve or remand PRC-006-0 until the ERO submitted the additional information.[7]

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[3] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[4] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[5] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 603, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[6] *Id.* P 1479.

[7] *Id.* PP 1477, 1479.

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B. NERC Petition

5. On March 31, 2011, NERC filed a petition seeking Commission approval of Reliability Standards PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans), and the concurrent retirement of the currently-effective Reliability Standards PRC-007-0, PRC-009-0, and EOP-003-1, and the NERC-approved Reliability Standard PRC-006-0. The petition, as amended on May 17, 2011, states that PRC-006-1 establishes design and document requirements for UFLS programs that arrest declining frequency and assist recovery of frequency following system events leading to frequency degradation.[8] The petition states that EOP-003-2 makes minimal changes to EOP-003-1 by removing references to UFLS, which NERC describes as redundant in light of PRC-006-1, and instead focuses EOP-003-2 on undervoltage conditions.

6. The petition states that Reliability Standard PRC-006-1 achieves a specific reliability goal by establishing design and documentation requirements for automatic UFLS programs to arrest declining frequency, assist recovery of frequency following underfrequency events, and provide last resort system preservation measures. Further, the petition states that PRC-006-1 contains a technically sound method to achieve its reliability goal by establishing a framework for developing, designing, assessing and

[8] The Notice of Proposed Rulemaking in this docket included a primer on UFLS programs generally. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Notice of Proposed Rulemaking, 76 Fed. Reg. 66,220 (October 26, 2011), FERC Stats. & Regs. ¶ 32,682 (2011).

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coordinating UFLS programs, and that PRC-006-1 is clear and unambiguous regarding what is required and who is required to comply with the Reliability Standard.

7. In the petition, NERC proposes VRFs and VSLs, an implementation plan, and an effective date. The petition requests an effective date for Reliability Standards PRC-006-1 and EOP-003-2 of one year following the first day of the first calendar quarter after applicable regulatory approvals with respect to all Requirements of the Reliability Standards *except* Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1. With respect to Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1, NERC requests an effective date of one year following the receipt of the generation data that would be required in draft Reliability Standard PRC-024-1[9] but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

C. Notice of Proposed Rulemaking

8. On October 20, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve Reliability Standards PRC-006-1 and EOP-003-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission proposed to approve PRC-006-1 and EOP-003-2 because the UFLS program addressed in the Reliability Standards is important to arresting declining frequency and

[9] Draft Reliability Standard PRC-024-1 addresses "Generator Performance During Frequency and Voltage Excursions" and is currently being developed in the NERC standard drafting process.

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assisting recovery of frequency following system events that lead to system instability, which can result in a blackout. The NOPR stated that the Reliability Standards are necessary for reliability because UFLS is used in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island. The NOPR concluded that PRC-006-1, in conjunction with the conforming changes to EOP-003-2, provides last resort Bulk-Power System preservation measures by establishing the first national Reliability Standard of common performance characteristics that all UFLS programs must meet.

9. The NOPR proposed to approve the related VRFs and VSLs, implementation plan, and effective date proposed by NERC. The NOPR also proposed to approve the regional variance for WECC in Reliability Standard PRC-006-1.

10. While proposing to approve Reliability Standards PRC-006-1 and EOP-003-2, the NOPR addressed or sought comments on the following issues: (A) impact of resources not connected to the bulk electric system; (B) validation of power system models used to simulate UFLS programs; (C) scope of UFLS events assessments; (D) impact of generator owner trip settings outside of the UFLS program; (E) UFLS program coordination with other protection systems; (F) identification of island boundaries in UFLS programs; (G) automatic load shedding in PRC-006-1 and manual load shedding in EOP-003-2; (H) elimination of balancing authority responsibilities in EOP-003-2; and (I) the “Lower VSL” for Requirement R8 and the “Medium” VRF for Requirement R5 of PRC-006-1.

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11. In response to the NOPR, comments were filed by NERC and 12 interested persons.[10] The comments generally support the approval of Reliability Standards PRC-006-1 and EOP-003-2. The comments also provide information responsive to the questions raised in the NOPR. In the discussion below, we address the questions raised in the NOPR in light of the comments.

II. Discussion

12. The Commission approves Reliability Standards PRC-006-1 and EOP-003-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission's approval is consistent with the broad support for the Reliability Standards expressed in the comments. The UFLS program addressed in Reliability Standard PRC-006-1 is important to arresting declining frequency and assisting recovery of frequency following system events that lead to system instability, which can result in a blackout. Accordingly, the Reliability Standard is necessary for reliability because UFLS is used in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island. PRC-006-1, in conjunction with the conforming changes to EOP-003-2, provides last resort Bulk-Power System preservation measures by establishing the first national Reliability Standard of common performance characteristics that all UFLS programs must meet. For the same reasons, we approve the regional

[10] A list of the commenters is provided in the Appendix.

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variance for WECC in PRC-006-1. We also approve the VRFs and VSLs designated for the requirements of the Reliability Standards, with modifications, and the implementation plan and effective date, as proposed by NERC.

13. We address below the following issues raised in the NOPR in light of the comments received: (A) impact of resources not connected to the bulk electric system; (B) validation of power system models used to simulate UFLS programs; (C) scope of UFLS events assessments; (D) impact of generator owner trip settings outside of the UFLS program; (E) UFLS program coordination with other protection systems; (F) identification of island boundaries in UFLS programs; (G) automatic load shedding in PRC-006-1 and manual load shedding in EOP-003-2; (H) elimination of balancing authority responsibilities in EOP-003-2; and (I) the "Lower VSL" for Requirement R8 and the "Medium" VRF for Requirement R5 of PRC-006-1. Regarding the last issue, the Commission directs NERC to modify the "Lower VSL" for Requirement R8 of PRC-0061 and the "Medium" VRF for Requirement R5 of PRC-006-1 consistent with the discussion below.

A. Impact of Resources Not Connected to Bulk Electric System Facilities

14. Requirement R2 of Reliability Standard PRC-006-1 requires planning coordinators to identify islands to serve as a basis for designing UFLS programs. Requirement R3 addresses performance characteristics for UFLS programs. Requirement R4 requires each planning coordinator to conduct and document the assessment of its UFLS design and determine if the UFLS program meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulations outlined

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in Requirement R4 all concern individual generating units greater than 20 MVA gross nameplate rating or generating plants/facilities greater then 75 MVA "connected to the bulk electric system."

15. In the NOPR, the Commission stated that some generation meeting the 20 MVA and 75 MVA criteria in Reliability Standard PRC-006-1, Requirement R4 would not be modeled pursuant to Requirement R4 because it is not connected to bulk electric system facilities. The Commission explained that a resource not directly connected to the bulk electric system may serve load designed to be shed in a UFLS program. The Commission expressed concern that failure to account for resources not directly connected to the bulk electric system could result in planning coordinators being unaware of how those resources respond to underfrequency conditions. The Commission stated that if a planning coordinator is unaware of how these resources respond, it may plan to shed more load than is necessary for an area's frequency to return to normal, which could cause an unintended overfrequency condition if the plan is carried out in the operating timeframe. These conditions, in turn, could cause the UFLS program to violate the performance characteristics specified in Requirement R3 of PRC-006-1. The Commission sought comment as to whether and how all resources required for the reliable operation of the bulk electric system, including resources not connected to bulk electric system facilities, are considered in the development of UFLS programs under Requirements R3 and R4 of PRC-006-1.

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Comments

16. NERC agrees with the NOPR that failing to model qualifying generation not directly connected to the bulk electric system could affect the simulated frequency response. NERC, however, clarifies that Reliability Standard PRC-006-1 does not "establish parameters for what resources are modeled in [] simulations" and that "power system models used in UFLS assessments are generally the same models used in transmission planning assessments, which include models of all generation units and plants that meet the threshold size requirements even those not connected directly to the Bulk Electric System."[11] In addition, NERC states that a standard authorization request is under development as part of the "second phase" of the project to revise the definition of bulk electric system, and information developed as part of that project could be used to assess whether any changes are needed to PRC-006-1.

17. EEI, TAPS, MISO, and FRCC maintain that the vast majority of qualifying generation is accounted for in Reliability Standard PRC-006-1. EEI comments that bulk electric system resources account for the "vast majority of resources within all interconnections" and supports the standard drafting team's belief that the Reliability Standard generally captures about 95 percent of utility-owned installed capacity.[12] While EEI acknowledges that there are a small number of unaccounted for generation resources

[11] NERC Comments at 4.

[12] EEI Comments at 2-3.

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that meet the qualifying criteria, EEI comments that what is captured is sufficient for assessing reliable operation of the bulk electric system. EEI also maintains that planning coordinators already consider other resources as appropriate.

18. TAPS states that the "great majority" of generators are not set to trip before the underfrequency set points, so they will be available for UFLS programs.[13] TAPS contends that the only generators of concern are those that: (1) do not meet Reliability Standard PRC-006-1's size and connection criteria; (2) trip prior to underfrequency set points; and (3) are dispatched during underfrequency events because they are not required to be modeled under PRC-006-1. TAPS maintains that the number of generators that meet these criteria is "very small" so that modeling them would have an "infinitesimal reliability benefit," not improving the overall accuracy of the UFLS program design and not justifying the additional costs.[14]

19. MISO states that UFLS simulations should not be required to include all generation that meets the 20 MVA and 75 MVA criteria in Reliability Standard PRC-006-1, Requirement R4. MISO cites the standard drafting team's belief that PRC-006-1 captures about 95 percent of utility-owned installed capacity.[15] MISO also

[13] TAPS Comments at 4.

[14] *Id.* at 4-5.

[15] MISO Comments at 3.

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maintains that the standard drafting team deserves deference and that simulations will always contain some degree of uncertainty.

20. FRCC states that generators that fall within the size requirements of Reliability Standard PRC-006-1 but that are not connected to bulk electric system facilities constitute a "very small amount."[16] FRCC maintains that this amount is well below the error tolerance of a well-designed UFLS program and, thus, is not important.

21. SWPA states that planning coordinators, in developing UFLS programs, should consider all resources that are determined to be required for the reliable operation of the bulk electric system, regardless of whether those resources are directly connected to the bulk electric system.

22. NYISO comments that it analyzes UFLS effectiveness using a Multiregional Modeling Working Group dynamics model of the Eastern Interconnection, which includes all resources on the system regardless of bulk electric system connections.

Commission Determination

23. In the NOPR, the Commission expressed concern regarding the development of UFLS programs that fail to account for qualifying generation not directly connected to the bulk electric system. We are satisfied with the explanations provided by commenters. First, we are persuaded by NERC's explanation that Reliability Standard PRC-006-1 does not limit the resources that can be modeled in the UFLS assessments and that power

[16] FRCC Comments at 2.

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system models used in UFLS assessments generally model all qualifying generation, including resources not directly connected to the bulk electric system. In summary, although PRC-006-1 does not require all of the generation that is not directly connected to the bulk electric system to be included in the modeling, the subset of these resources that are required to assure that the UFLS models are sufficient to accurately predict system performance will be included. Similarly, we accept comments from EEI, TAPS, MISO, and FRCC that PRC-006-1 requires modeling of the vast majority of qualifying generation to ensure the reliable operation of the bulk electric system.

24. Like SWPA, the Commission believes that requiring all qualifying assets to be accounted for in UFLS programs, regardless of whether they are directly or indirectly connected to the bulk electric system, is useful to ensuring the effectiveness of the programs. Not requiring applicable entities to model sufficient amounts of qualifying generation indirectly connected to the bulk electric system could result in applicable entities not knowing how those resources react during underfrequency situations, which could cause excessive load shedding in an emergency and further contribute to system instability.

25. NERC states in its comments that this issue could be further evaluated in the "second phase" of the project to revise the definition of bulk electric system, and that information from that project could be used as a basis for revising Reliability Standard

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PRC-006-1 if necessary.[17] Without prejudging those efforts, the Commission will not issue a directive requiring the modeling of qualifying generation not directly connected to the bulk electric system.

B. Validation of Power System Models

26. In the NOPR, the Commission stated that dynamic simulations that fail to accurately represent the power system can result in UFLS programs that are ineffective. The Commission, however, concluded that the UFLS program design requirements established in Requirement R2 of Reliability Standard PRC-006-1 and the required assessments established in Requirements R4 and R11 of PRC-006-1 are generally acceptable and include improvements over the current Reliability Standards.

Comments

27. FRCC comments that improving the accuracy of power system models used in simulating system response to forecasted system conditions is an appropriate goal, but achieving 100 percent accuracy is not practicable. EEI comments that dynamic simulations for any large power system will never be 100 percent accurate and asks the Commission not to impose any new directives which might unnecessarily increase costs to industry.

28. NYISO states that a lack of accuracy in modeling can have a significant impact on analyses of under-generated islands. Specifically, NYISO states that "optimistic models

[17] NERC Comments at 5.

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of unit governing response can lead to invalid conclusions regarding minimum frequency and frequency recovery."[18] NYISO indicates that it is taking steps to improve the accuracy of modeling frequency recovery by, among other things, aligning the dynamics model to observed system response.

Commission Determination

29. The Commission accepts the comments from EEI and FRCC that power system models with 100 percent accuracy are not practicable. The Commission, however, is mindful of the consequences of inaccurate power system models and their impact on an entity's ability to accurately simulate system performance. As noted by NYISO, inaccurate models can lead to invalid conclusions which can be detrimental to the analysis and operation of the bulk electric system. At a minimum, the models should accurately predict system performance during UFLS events. Although entities may take additional steps, such as the step taken by NYISO to ensure accurate models, as stated in the NOPR, the Commission believes that the design requirements in Reliability Standard PRC-006-1 are acceptable.[19]

C. UFLS Event Assessments

1. Assessments in the Absence of Island Formation

30. Requirement R11 of Reliability Standard PRC-006-1 requires planning coordinators to conduct assessments after a "BES islanding event results in system

[18] NYISO Comments at 3.

[19] NOPR, FERC Stats & Regs, ¶ 32,682 at P 34.

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frequency excursion below the initializing set points of the UFLS program."

31. In the NOPR, the Commission expressed concern that the phrase "BES islanding event" could be interpreted to mean that a planning coordinator only has to assess an event if it meets both of the following requirements: (1) system frequency excursions fall below the initializing set point for UFLS; and (2) bulk electric system islands form within the Interconnection. The Commission explained that, if frequency falls below the initializing UFLS set point but islands do not form (e.g., because the event was not severe enough to isolate portions of the Interconnection, or UFLS or other protection systems failed to operate properly to form islands), an assessment of the performance of the UFLS program for this event is still useful because it can determine if the UFLS program operated as expected. The Commission sought comment on what actions must planning coordinators take under Requirement R11 of PRC-006-1 if an event results in system frequency excursions falling below this initializing set point for UFLS but without the formation of a bulk electric system island.

Comments

32. In its comments, NERC states that "[a]lthough PRC-006-1 does not prescribe an analysis for [the non-islanding scenario identified in the NOPR], activating UFLS during an Interconnection-wide event would involve a significant loss of generation and analysis would be performed under the NERC Event Analysis program or the NERC Rules of

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Procedure, depending on the severity of the event."[20] NERC further states that the "activation of UFLS, while highly unlikely, would be a significant event requiring assessment of several aspects of system frequency, including system Frequency Response, equipment performance, and coordination of protection and control systems, in addition to the assessment of UFLS program operation."[21] Ultimately, NERC agrees that an assessment of the performance of UFLS, even in the absence of island formation, is useful.

33. EEI and MISO agree with NERC that Requirement R11 of Reliability Standard PRC-006-1 requires both conditions (i.e., frequency excursion and islanding) to be met. MISO agrees with the NOPR that an analysis of excursions without islanding is useful. However, MISO and EEI comment that such an analysis is outside the scope of the Reliability Standard. MISO, quoting the NOPR, states that UFLS "is designed for use in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed."[22] Accordingly, MISO argues that a UFLS program "can only truly be assessed in light of its performance after an island has formed."[23] In addition, such assessments are costly, time consuming and resource intensive, according to MISO. EEI maintains that entities "broadly perform assessments of lesser events as they deem

[20] NERC Comments at 6.

[21] *Id.*

[22] MISO Comments at 4 (*citing* NOPR, FERC Stats & Regs. 32,682 at P 35).

[23] *Id.*

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necessary."[24] EEI contends that such assessments are not required in PRC-006-1 because "to do so would go beyond the intent of the program which is the design of UFLS programs."[25] Instead, EEI notes that applicable entities normally conduct operational assessments regularly, and if an entity identifies a problem the entity would report the matter as a misoperation with an obligation to remediate. EEI also points to the draft NERC Event Analysis Process[26] and its application to what EEI describes as "underfrequency events of a lesser level" (i.e., events resulting in load shedding with a loss of load of 100 MW or more).[27] EEI contends that the Commission's concerns regarding analysis of lesser events will be satisfied once the NERC Event Analysis Process is finalized.

34. SWPA states that it is reasonable for planning coordinators to request and analyze event data in the absence of island formation to assess the performance of UFLS programs. Specifically, SWPA comments that "[t]he assessment of a UFLS event during varying system conditions caused by generator outages, transmission outages, and

[24] EEI Comments at 5.

[25] *Id.*

[26] We understand the NERC Event Analysis Process to be the same as the NERC Event Analysis program referenced in NERC's comments.

[27] *Id.*

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various maintenance activities, provides an opportunity to discover the impacts of these activities on the expected outcomes described in the plan."[28]

Commission Determination

35. NERC clarifies that Requirements R11 and R12 of Reliability Standard PRC-006-1 are triggered when system frequency excursions fall below the initializing set points for UFLS programs and bulk electric system islands form within Interconnections.[29]

36. The Commission agrees with commenters that it would be useful to have an analysis of system frequency excursions to assess the performance of UFLS programs even in the absence of island formation.[30] To that end, we agree with NERC that underfrequency events that result in the initializing of the UFLS set point, even in the absence of island formation, would be analyzed under provisions contained in the NERC Rules of Procedure and the NERC Event Analysis program.[31]

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[28] SWPA Comments at 3.

[29] NERC Comments at 6.

[30] NERC Comments at 5; MISO Comments at 4; SWPA Comments at 3.

[31] NERC Comments at 6. Section 807 of the NERC Rules of Procedure addresses "Analysis of Major Events" and Section 808 addresses "Analysis of Off-Normal Events, Potential System Vulnerabilities, and System Performance." Separately, the NERC Event Analysis program, which is not incorporated in the NERC Rules of Procedure, as of this time is still under development. Compliance with the NERC Rules of Procedure is mandatory pursuant to section 39.2(b) of the Commission's regulations and is enforceable by the Commission pursuant to section 39.9 of the Commission's regulations. 18 C.F.R. § 39.2(b) ("All entities subject to the Commission's reliability

(continued…)

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2. Coordination of Assessments and Results

37. Requirements R5 and R13 of Reliability Standard PRC-006-1 provide flexibility in coordinating UFLS design programs and event assessments among planning coordinators whose areas fall within the same island or whose areas are affected by the same event. In the NOPR, the Commission sought comments on whether differences in assessments between planning coordinators should be reported to reliability coordinators for resolution in the event that the process identified in PRC-006-1 does not resolve the differences.

Comments

38. NERC, MISO, and EEI comment that reliability coordinators should not be tasked with resolving differences between planning coordinator event assessments. NERC states that differences between planning coordinator event assessments should not be reported to reliability coordinators because: (1) reliability coordinator's wide-area view may not coincide with island boundaries; (2) reliability coordinators may have conflicts of interest; (3) reliability coordinators may not have the tools to resolve the differences; and (4) reliability coordinators work in a real-time operating environment, which makes them ill-suited to resolve disputes among planning coordinators.

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jurisdiction under paragraph (a) of this section shall comply with applicable Reliability Standards, the Commission's regulations, and applicable Electric Reliability Organization and Regional Entity Rules made effective under this part."); 18 C.F.R. § 39.9.

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39. MISO and EEI comment that event assessment differences should not be reported to reliability coordinators because planning coordinators are better positioned to reconcile differences. MISO notes that in some cases where an applicable entity is both a reliability coordinator and planning coordinator (as is the case with MISO), there would be a conflict of interest. Further, MISO maintains that referring disputes to reliability coordinators imposes additional costs with little to no benefit. MISO and EEI also contend that event assessment differences do not pose a risk to the reliability of the bulk electric system, with EEI noting that such differences are "a result of legitimate engineering and regional practices and processes."[32] At most, EEI suggests that reliability coordinators might be used as informal facilitators.

40. SWPA states that a clear resolution process is necessary and that referring disputes to reliability coordinators is a reasonable consideration.

Commission Determination

41. The Commission is persuaded by the comments of NERC, MISO, and EEI that differences between planning coordinator event assessments should not be referred to reliability coordinators for resolution. We share the concern of NERC, MISO, and EEI that referring disputes to reliability coordinators may create conflicts of interest because a planning coordinator may also serve as a reliability coordinator. We agree, however, with SWPA that disputes between planning coordinator event assessments should be

[32] EEI Comments at 6.

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resolved. Therefore, the Commission expects planning coordinators to work in good faith including, as appropriate, use of third parties to resolve disputes concerning event assessments. If the Commission finds that these disputes are not being resolved, the Commission may consider adoption of an appropriate process to ensure resolution of the disputes.

3. Assessment Timeline for Completion

42. Requirement R11 of Reliability Standard PRC-006-1 requires planning coordinators to perform island event assessments within one year of an event. If the planning coordinator identifies program deficiencies, Requirement R12 of PRC-006-1 requires planning coordinators to conduct and document UFLS design assessments, which are meant to consider the deficiencies, within two years of an event.

43. In the NOPR, the Commission expressed concern that this time frame could be too long because island event assessments and consideration of deficiencies could reasonably be done in a shorter time frame. Moreover, the Commission noted that under PRC-006-1, deficiencies could remain within a UFLS program for two years from an event exposing the Bulk-Power System to instability, uncontrolled separation and cascading outages should a frequency event occur that the UFLS program mishandles. The Commission sought comments on the basis for the two-year time frame and clarification as to how soon after an event would an entity need to implement corrections in response to any deficiencies identified in the event assessment under Requirement R11 of PRC-006-1.

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Comments

44. NERC comments that, while some events can be assessed in less time, one year is a realistic time-frame to assess performance for complex events and two years is a realistic time-frame to address identified deficiencies. NERC states that "the amount of time that a UFLS entity has to implement corrections will be established by the Planning Coordinator, as specified in Requirement R9 of PRC-006-1 . . . [and] [t]he time allotted for corrections will depend on the extent of the deficiencies identified."[33]

45. EEI, MISO, and G&T Cooperatives support the timelines in Reliability Standard PRC-006-1. MISO maintains that event assessments are time and resource intensive and must not be rushed. EEI, MISO, and G&T Cooperatives state that planning coordinators can complete analyses of less complex events before the two-year deadline, but they need the maximum allowable time to finish analyses of complex events. With respect to the time allowed for correcting problems, EEI comments that any deadline in a requirement would be difficult to enforce and would not improve reliability given the variable nature of possible deficiencies.

46. SWPA states that an applicable entity may need to implement corrections that require complex procurement or acquisition processes, and such contracts can be complex, involving many required decisions and actions. Given these complexities,

[33] NERC Comments at 8.

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SWPA maintains that four years after event actuation is a reasonable deadline to implement corrections.

Commission Determination

47. Based on the comments, the Commission is persuaded that two years to complete design assessments pursuant to Reliability Standard PRC-006-1 is appropriate. As noted by EEI, MISO, and G&T Cooperatives, assessments of complex events can be time and resource intensive. Thus, we agree that two years is a reasonable maximum allowable time for completion of design assessments. However, we agree with commenters that efforts should be made to complete assessments of less complex events before the two-year maximum allowable period.[34]

48. In response to the Commission's concern that Reliability Standard PRC-006-1 does not specify how soon after an event would an entity need to implement corrections in response to any deficiencies identified in the event assessment under Requirement R11 of PRC-006-1, NERC stated in its comments that:

> The amount of time that a UFLS entity has to implement corrections will be established by the Planning Coordinator, as specified in Requirement R9 of PRC-006-1. The time allotted for corrections will depend on the extent of the deficiencies identified. The schedule specified by the Planning Coordinator will consider the time necessary for budget planning and implementation, recognizing that operating and maintenance budgets normally will not be sufficient to address major revisions and allowances will be

[34] EEI Comments at 7; MISO Comments at 6.

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> necessary for inclusion of approved changes in budgeting cycles.[35]

Requirement R9 of PRC-006-1 states:

> **R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF:High][Time Horizon: Long-term Planning]*

Notwithstanding NERC's comments, the Commission is not persuaded that Requirement R9 requires corrective action in accordance with a schedule established by the planning coordinator. Based on its comments, however, NERC has expressed no opposition to such a requirement. We accept NERC's comments that Requirement R9 requires a schedule established by the planning coordinator, but NERC's reading of Requirement R9 should be made clear in the Requirement itself. Accordingly, we direct NERC to make that requirement explicit in future versions of the Reliability Standard. Within 30 days of the effective date of this Final Rule, NERC is directed to submit a compliance filing indicating how it plans to comply with this directive and a deadline for compliance.

D. Generator Owner Trip Settings Outside of the UFLS Program

49. In the NOPR, the Commission stated that Requirements 4.1 through 4.7 of Reliability Standard PRC-006-1 are intended to capture the effects of generators that trip prior to UFLS initiation. While agreeing that planning coordinators should consider

[35] NERC Comments at 8.

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generators that trip prior to underfrequency set points when developing their UFLS programs, the Commission sought comments on how generation losses outside of the UFLS set points (i.e., generators having trip settings prior to the UFLS underfrequency set points) should be accounted for in UFLS programs (e.g., generator owners who trip outside of the UFLS set points could procure load to shed to account for the loss in generation).

Comments

50. NERC, EEI, TAPS, Dominion, FRCC and EPSA oppose requiring generator owners to procure load to shed for generators that trip outside of the UFLS set points. NERC states that it is appropriate for planning coordinators to consider generators that trip outside of the UFLS set points when designing UFLS programs, but it is inappropriate for planning coordinators to determine whether mitigation is necessary and who will be responsible for providing mitigation.

51. EEI states that Reliability Standard PRC-006-1, Requirement R4 requires that all resources included in the UFLS program that operate outside the specified trip settings be factored in to the dynamic simulation models used to develop the program. EEI further notes that, while there is no formal obligation for generator owners to supply trip setting data to planning coordinators, this information is shared. Unlike modeling generators that trip outside of the UFLS set points, EEI maintains that the issue of procuring load to shed to compensate for such trips is outside the scope of PRC-006-1.

52. TAPS comments that generators that trip prior to underfrequency set points are separately modeled under Reliability Standard PRC-006-1 and that this is the correct

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approach to account for such generators. TAPS opposes requiring generator owners who trip outside of the UFLS set points to procure load to shed to account for the loss in generation. TAPS objects to a "one-size-fits all market/contractual solution" given the absence of a demonstrable reliability problem and the market power concerns it might create.[36] TAPS maintains that in some small islands it may be impossible to procure the necessary load to shed.

53. Dominion states that generator owners whose generators trip prior to UFLS set points should not be required to procure load to shed. Dominion contends that such a scheme could be extremely difficult to design and coordinate, and Dominion is unaware of any distribution provider or transmission owner tariff that offers such a service.

54. FRCC maintains that a small minority of generator underfrequency protection settings are above the minimum UFLS frequency set points and that in many cases any conflicts can be resolved by reexamination of the technical basis for the generator's underfrequency protection. FRCC also states that requiring generator operators to procure load to shed would be technically impossible, and there is no market for compensatory, assignable UFLS to make generator contracts for load shedding feasible.

55. EPSA states that planning coordinators should consider generators that trip prior to underfrequency set points when collecting information and developing their UFLS programs. EPSA maintains, however, that requiring planning coordinators to account for

[36] TAPS Comments at 7.

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generators that trip prior to the UFLS set points presupposes that there is a material amount of generator losses occurring. EPSA believes that implementation of Reliability Standard PRC-006-1 will allow planning coordinators to gather information to determine the amount of losses, which can then be used to decide whether generator losses need to be accounted for. EPSA states that if generator losses are found to be a material concern that needs to be accounted for, the Commission should consider that: (1) generator owners do not and cannot play an active role in UFLS program decisions; (2) generator owners do not determine the set points for their generation; and (3) the NERC process should not be used to influence market decisions and competitiveness.

56. SWPA states that the design assessment in Requirement R4 of Reliability Standard PRC-006-1 addresses the modeling of generators having trip settings prior to the UFLS set points but that the Reliability Standard does not address how planning coordinators would resolve the need for supplemental UFLS. SWPA maintains that PRC-006-1 should include a requirement for planning coordinators to identify the UFLS entity that needs to provide supplemental UFLS, the basis for the identification, and coordination of this information with those entities and affected generator owners.

57. NYISO states that it conducts an annual survey of all generator owners within the New York Control Area for their UFLS trip setting and addresses those that have settings outside the UFLS program range established by the Northeast Power Coordinating Council (NPCC). NYISO states that it conducts a UFLS simulation that excludes non-conforming generation and a separate simulation that incorporates 260 MW of compensatory load shedding with tripping of non-conforming generation.

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Commission Determination

58. Based on the comments, the Commission is persuaded to take no action to require compensation for generation losses outside of the UFLS set points (i.e., generators having trip settings prior to the UFLS underfrequency set points). Reliability Standard PRC-006-1 is an improvement because it requires planning coordinators to consider generators that trip outside of the UFLS set points when modeling and designing UFLS programs. We are persuaded by NERC's comments that it is appropriate for planning coordinators to consider generators that trip outside of the UFLS set points when designing UFLS programs, but it is inappropriate for planning coordinators to determine whether mitigation is necessary and who will be responsible for providing mitigation. For these reasons, we take no action to modify the Reliability Standard.

E. UFLS Program Coordination with Other Protection Systems

59. In the NOPR, the Commission stated that an integrated approach to the coordination of all types of protection systems (e.g., UFLS, undervoltage load shedding[37]), internally and externally to an entity's area, is required to be responsive to the 2003 Blackout Report.[38] The Commission noted that, while Reliability Standard

[37] Undervoltage load shedding (UVLS) is automatic load-shedding that sheds load to prevent local area voltage collapse. *See U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, at 92 (Apr. 2004) (Blackout Report), *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout.asp.

[38] Blackout Report at 159.

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PRC-006-1 requires coordination of UFLS programs among planning coordinators in Requirements R5, R7, and R13, it does not appear to capture the same level of coordination with other protection systems as in Requirement R1.2.8 of PRC-006-0, which was approved by the NERC Board of Trustees but left pending in Order No. 693.[39] The Commission sought comments on whether and how coordination with other protection systems is or is not achieved under the new requirements.

Comments

60. NERC states that Requirement R1.2.8 of PRC-006-0 includes a broad mandate and that the intent was to replace it with more specific requirements that are clear and measurable. NERC contends that Requirements R3, R4, and R10 of Reliability Standard PRC-006-1 include requirements for the coordination of UFLS programs with specific protections that "are part of or could impact the UFLS program."[40] EEI and G&T Cooperatives likewise believe that Requirement R1.2.8 is vague, while PRC-006-1 contains the specificity to ensure that UFLS programs are adequately designed and coordinated. G&T Cooperatives maintains that coordination of UFLS and UVLS programs is already provided for in PRC-010-0, Requirement R1.1.1.

61. FRCC states that there is seldom a need to coordinate UFLS with UVLS and that the Reliability Standard PRC-006-1 correctly identifies the protection systems that

[39] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1477, 1479.

[40] NERC Comments at 9.

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entities should coordinate with UFLS programs. FRCC contends that the potential for interaction between UFLS and UVLS programs is minimal given that UVLS schemes are not deployed throughout an interconnection and are, instead, deployed in specific locations that may be exposed to low voltage for a specific contingency. NYISO likewise states that, due to the distributed nature of UFLS, there should not be any significant interaction between fault clearing protections and UFLS and that under-voltage inhibition of relays is not expected to interfere with UFLS programs.

Commission Determination

62. With regard to our concern raised in the NOPR regarding the coordination of UFLS with other protection systems, we are persuaded by NERC's comments that Reliability Standard PRC-006-1 provides an adequate level of coordination between the UFLS program and specific protection systems and controls that NERC identifies as part of, or could impact, the UFLS program.[41]

63. We are persuaded by NERC comments that "Requirements R3, R4, and R10 of PRC-006-1 address coordination of the UFLS program with other protection and control systems . . . includ[ing] generator protections that could respond to frequency and voltage excursions, automatic Load restoration, and equipment switching that may be included in

[41] It may be appropriate to address an integrated approach to the coordination of all protections systems, as recommended by the Blackout Report, but that issue is outside the scope of this proceeding addressing Reliability Standard PRC-006-1.

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the UFLS program to control voltage."[42] Specifically, planning coordinators are to coordinate expected generation performance during underfrequency events and generator trip settings under PRC-006-1, Requirements R3 and R4.[43] To satisfy PRC-006-1, Requirement R10, transmission owners must provide the necessary automatic switching of elements as directed by the planning coordinator in the UFLS program and schedule.[44] To maintain the required system restoration capability required by PRC-006-1, Requirement R10, transmission owners must coordinate other protection system components with the established UFLS program components.

64. Additionally, the Commission notes that currently-effective Reliability Standard PRC-001-1 (System Protection Coordination) ensures system protection coordination for protection systems.[45] The Commission believes that this level of coordination between UFLS programs and other specific protection systems is adequate.

F. Identification of Island Boundaries

65. Requirement R1 of Reliability Standard PRC-006-1 directs planning coordinators to develop criteria to select areas that may form islands based on historical events and system studies. Historical events and system studies provide planning coordinators with the data necessary to determine where islands will occur based on the physics of the

[42] NERC Comments at 9

[43] *Id.* at 9-10.

[44] *Id.* at 11.

[45] Reliability Standard PRC-001-1, Requirements R1 and R3.

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system. Requirement R2.3 of PRC-006-1 allows planning coordinators to "adjust the island boundaries to differ from the Regional Entity area boundaries by mutual consent where necessary" to preserve contiguous island boundaries that better reflect simulations.

66. In the NOPR, the Commission agreed with the premise behind Requirement R1, which requires identifying island boundaries based on where they are likely to occur as opposed to following rigid Regional Entity area boundaries, because it should result in more effective UFLS programs. The NOPR also noted that NERC, in its petition, stated that Reliability Standard PRC-006-1 allows planning coordinators to "select islands including interconnected portions of the bulk electric system in adjacent Planning Coordinator areas and Regional Entity areas, without the need for coordinating this selection with Planning Coordinators in neighboring regions."[46] The Commission observed, however, that Requirement R2.3 of PRC-006-1 requires "mutual consent" to adjust island boundaries from Regional Entity boundaries. The Commission sought clarification concerning the required degree of cooperation and/or "mutual consent" between planning coordinators under the proposed Reliability Standard.

Comments

67. In its comments, NERC clarifies that "mutual consent" is required by part 2.3 of Requirement R2 of Reliability Standard PRC-006-1 when planning coordinators select island boundaries that do not coincide with the Regional Entity area or Interconnection

[46] NERC Petition at 75-76.

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boundary. NERC explains that, when a planning coordinator selects an island boundary that does not coincide with the Regional Entity area or Interconnection boundary, mutual consent must be obtained from neighboring planning coordinators to ensure that the deviation does not result in a portion of the bulk electric system being excluded from a UFLS assessment.

68. EEI states that the Reliability Standard PRC-006-1 requires "mutual consent" between affected planning coordinators and that the level of consent is voluntary and undefined to allow the parties to determine the level of cooperation necessary. EEI maintains that this scheme is necessary to ensure that all parts of the bulk electric system are covered within a UFLS plan.

69. MISO states that planning coordinators should be able to study islands as they see fit and without the consent of neighboring planning coordinators, which includes studying islands that deviate from Regional Entity boundaries. MISO maintains that there is no detrimental effect associated with multiple or non-coordinated island studies.

70. NYISO comments that it regularly conducts stability evaluations on a New York Control Area and regional basis and is aware of the potential breakpoints on the system.

71. EPSA states that UFLS programs are best developed on an interconnection-wide basis, not on a regional basis. EPSA notes that region-specific Reliability Standards could undermine Reliability Standards PRC-006-1 and EOP-003-2 if they do not address interregional coordination among planning coordinators.

72. PSEG states that it has concerns with the active draft regional versions of PRC-006-1 pertaining to Reliability*First* Corporation and NPCC. PSEG maintains that

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these regional versions will hamper needed interregional coordination for UFLS program design in the Eastern Interconnection (i.e., the proposed regional standards do not require interregional coordination among planning coordinators and may require planning coordinators who span multiple regions to follow different standards); they violate a key NERC market principle by requiring existing generator owners to procure offsetting UFLS for the early tripping of their generating units if these units cannot meet specific performance requirements; and they may contravene the Energy Policy Act of 2005[47] by placing NERC and the regions in the role of imposing generation adequacy requirements. PSEG maintains that UFLS is an interconnection-wide issue and should be addressed on an interconnection-wide basis.

Commission Determination

73. The Commission accepts NERC's clarification of the level of consent required between planning coordinators to adjust island boundaries under Reliability Standard PRC-006-1, Requirement R2.3. As stated in the NOPR, we believe that the reliability of the bulk electric system benefits from entities basing their studies on physical characteristics, as allowed in PRC-006-1, as opposed to hewing to artificial boundaries.[48] To the extent MISO suggests in its comments that planning coordinators should not have to reach a consensus with neighboring planning authorities when adjusting island

[47] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[48] NOPR, FERC Stats & Regs. ¶ 32,682 at P 46.

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boundaries, we disagree. As NERC and EEI explain in their comments, it is important to coordinate adjustments in island boundaries to ensure that no part of the bulk electric system is inadvertently left unstudied.[49] However, nothing in PRC-006-1 precludes entities from conducting additional assessments based on any island boundaries they wish to analyze.

74. With respect to the comments from EPSA and PSEG, there are no Regional Reliability Standards currently before us in this matter and, therefore, the matter is not ripe for us to address.

G. Automatic Load Shedding and Manual Load Shedding

75. In the NOPR, the Commission observed that there are no requirements in Reliability Standard PRC-006-1 to coordinate automatic load shedding by UFLS and manual load shedding under Reliability Standard EOP-003-2. The Commission noted that once load is disconnected from the system, either automatically or manually, it cannot be used again to arrest frequency decline. The Commission expressed concern that in the event that a load resource is double-counted and removed during automatic UFLS, the manual load shedding cannot be completed if called upon. Accordingly, the Commission stated that resources allocated to each type of load shedding (i.e., automatic and manual) should not overlap. The Commission sought comments on how the

[49] NERC Comments at 12; EEI Comments at 10.

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coordination of automatic and manual load shedding is considered in light of the fact that the Reliability Standards do not explicitly require coordination.

Comments

76. NERC acknowledges that the Reliability Standards do not explicitly require coordination of manual load shedding and UFLS but states that Reliability Standard EOP-003-2 addresses the concern that a load resource could be unintentionally double-counted. Specifically, NERC maintains that Requirement R6 of EOP-003-2 requires transmission operators and balancing authorities to include load in the manual load shedding program that is not included in the UFLS program to achieve the reliability objective of EOP-003-2.[50]

77. Wisconsin Electric and FRCC state that it is difficult for a UFLS program not to overlap with manual loadshed plans. Wisconsin Electric comments that it is "overly conservative to prevent a load from being used in both a UFLS program and a manual loadshed plan."[51] Wisconsin Electric also observes that a reliability coordinator may require an entity to manually shed load that is part of a UFLS program, which the entity cannot ignore. FRCC maintains that a non-overlap rule is likely to have a negative impact on reliability because it may reduce the amount of load available to address

[50] NERC Comments at 12.

[51] Wisconsin Electric Comments at 3.

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capacity emergencies. FRCC further contends that underfrequency events are rare and it is even less likely for an underfrequency event to coincide with a capacity emergency.

78. Dominion states that the Commission should not force coordination of manual load shedding and UFLS load shedding because it would prevent balancing authorities and transmission operators from using currently available tools to manage emergency conditions. Dominion contrasts the precision of manual load shedding with the widespread automatic response provided by UFLS programs. According to Dominion, forced coordination could remove manual load shedding from the emergency response toolkit for local issues, which, according to Dominion, could allow them to turn into cascading events. EEI states that the purpose of UFLS programs and manual load shedding are separate. EEI argues that, while a broad understanding of the operation of each program is important, coordination to the level implied by the NOPR serves no purpose since each program addresses different problems. EEI further notes that coordination in the form of "information sharing" already occurs. NYISO also states that manual load shedding and UFLS address different issues and should be addressed in separate Reliability Standards.

79. SWPA states that there is a need to address what consideration planning authorities give to other protective schemes and remedial action plans. SWPA maintains that Reliability Standard PRC-006-1 should address how a balancing authority and transmission operator address overlap concerns where most of its balancing authority area entities are subject to load shedding plans under Reliability Standard EOP-003-2 but these loads are also subject to UFLS plans under PRC-006-1.

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Commission Determination

80. Based on the comments, we find that there is an adequate level of coordination between UFLS and manual load shedding. We are persuaded by NERC's comments that the term "additional load" in Reliability Standard EOP-003-2, Requirement R6, includes resources allocated to manual load shedding that are not included in the UFLS program. UFLS and manual load shedding programs are developed separately and have, as EEI stated, separate purposes. As such, to avoid insufficiencies in available load if manual load shedding is needed after UFLS has been activated, UFLS and manual load shedding programs cannot be planned to shed the same load.

H. Elimination of Requirements for Balancing Authorities in EOP-003-2

81. In the NOPR, the Commission observed that Requirements R2, R4, and R7 of the currently-effective Reliability Standard EOP-003-1 apply to transmission operators and balancing authorities but that Reliability Standard EOP-003-2 eliminates balancing authorities from Requirements R2, R4, and R7. The Commission sought clarification as to why these balancing authority responsibilities were not incorporated into Reliability Standards PRC-006-1 or EOP-003-2. The Commission also sought comments as to why balancing authorities should not be informed of UFLS program plans that directly impact balancing authority functions.

Comments

82. NERC states that Reliability Standard EOP-003-2 removes requirements on UFLS design, incorporates them in Reliability Standard PRC-006-1, and assigns those activities to planning coordinators. NERC further states that EOP-003-2 does not remove any

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requirements for UVLS, which are assigned to transmission operators. NERC maintains that, while balancing authorities contribute to managing Interconnection frequency by balancing load and generation resources in real-time, UFLS and UVLS programs are automatic and must be set in advance. NERC, however, agrees that balancing authorities should be informed of UFLS program plans that directly impact the balancing authority function.

83. EEI, TAPS, MISO, Dominion and NYISO largely support NERC's comments. EEI states that the changes in Reliability Standard EOP-003-2 are consistent with the roles and responsibilities of balancing authorities and transmission operators. EEI also maintains that balancing authorities are already informed of UFLS programs by transmission operators because balancing authorities and transmission operators "are specifically identified as coordinating other load shedding plans as identified in EOP-003-2" and to "effectively develop those plans [balancing authorities] and [transmission operators] must have knowledge of the UFLS programs of which [transmission operators] are intimately aware through PRC-006-1."[52]

84. TAPS states that Reliability Standards PRC-006-1 and EOP-003-2 clarify the requirements in the existing Reliability Standards and assign them to the functional entities best suited to program design. TAPS also states that Reliability Standard PRC-001-1, Requirement R1 ensures that balancing authorities are familiar with UFLS

[52] EEI Comments at 13.

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programs because the requirement provides that they "shall be familiar with the purpose and limitations of protection system schemes applied in its area."[53]

85. MISO states that balancing authorities need not be informed of UFLS programs because planning coordinators are the functional entities tasked with overseeing those programs. MISO also contends that requiring planning coordinators to report to balancing authorities on UFLS programs would impose additional costs with little benefit to reliability. MISO notes, however, that balancing authorities could benefit if NERC periodically published prevailing UFLS set points by planning coordinator area.

86. Dominion states that planning coordinators should not be required to inform balancing authorities of UFLS program plans because balancing authorities have no role in the design and implementation of UFLS and have no action to take to affect the successful operation of UFLS.

87. NYISO comments that balancing authorities have no role in load shedding and agrees with the removal of UFLS references from Reliability Standard EOP-003-2.

88. SWPA states that balancing authorities, by definition, do not perform the functions referred to in Reliability Standards PRC-006-1 or EOP-003-2, Requirements R2, R4, and R7. However, SWPA believes that PRC-006-1 should incorporate language that ensures that balancing authorities are kept informed of UFLS program plans that directly impact the balancing authority functions.

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[53] TAPS Comments at 8-9.

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Commission Determination

89. The Commission accepts the elimination of requirements for balancing authorities in Reliability Standard EOP-003-2. NERC states in its comments that "all activities required for UFLS programs in the existing standards are incorporated into PRC-006-1, and are assigned to the Planning Coordinator,"[54] and that balancing authorities will still be made aware of UFLS programs in order to "be familiar with the purpose and limitations of protection system schemes applied in its area,"[55] as stated in Reliability Standard PRC-001-1, Requirement R1. To that end, the Commission believes that the comments address the questions raised in the NOPR regarding the elimination of balancing authority responsibility for Requirements R2, R4, and R7 of EOP-003-2.

I. Violation Risk Factors and Violation Severity Levels

90. In the NOPR, the Commission proposed to approve the VRFs and VSLs in Reliability Standards PRC-006-1 and EOP-003-2. However, the Commission sought comments on one VSL and one VRF for PRC-006-1.

91. The Commission stated that the "Lower VSL" assignment for Requirement R8 in PRC-006-1 applies when a UFLS entity fails to provide data to its planning coordinator for 5 to 10 calendar days following the schedule specified by the planning coordinator. The Commission noted in the NOPR that Requirement R8 of PRC-006-1 does not

[54] NERC Comments at 13.

[55] NERC Comments at 14.

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include a 5-day grace period for providing data to planning coordinators and thus the subject VSL assignment may be inconsistent with the Commission's VSL Guideline 3.

92. The Commission noted that NERC proposed a "Medium" VRF for Reliability Standard PRC-006-1, Requirement R5, which requires planning coordinators to coordinate their UFLS program design with other planning coordinators whose area is in part of the same identified island. The Commission observed the statement in NERC's petition that Requirement R5 is "not related to similar reliability goals in other standards."[56] However, the Commission explained that coordination of load shedding plans is required in a similar manner in Requirement R3 of currently-effective Reliability Standard EOP-003-1, which includes a VRF of "High."[57] The Commission stated that the lack of coordination of UFLS programs among planning coordinators within the same identified island could lead to ineffective UFLS operations and further cascading outages within the island when UFLS is activated. The Commission explained that this might be inconsistent with Guideline 3 of the Commission's VRF Guidelines states that "[a]bsent justification to the contrary, the Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably."[58]

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[56] NERC Petition at 46.

[57] Reliability Standard EOP-003-2 includes the same VRF assignment of "High" for Requirement R3.

[58] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, at P 25 (2007).

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Comments

93. NERC agrees with the NOPR regarding both the "Lower VSL" for Requirement R8 of Reliability Standard PRC-006-1 and the VRF for Requirement R5 of PRC-006-1. In its comments, NERC proposes to modify the "Lower VSL" to remove the phrase "more than 5 calendar days but" to address the concern stated in the NOPR. NERC also proposes to modify the VRF for Requirement R5 by raising it from "Medium" to "High."

94. EEI, SWPA, and NYISO agree with the need to modify the VSL for Requirement R8 of PRC-006-1, consistent with NERC's proposal. NYISO also supports changing the VRF for PRC-006-1, Requirement R5.

Commission Determination

95. Consistent with the proposal in NERC's comments, the Commission directs the ERO to modify the language of the Lower VSL for Reliability Standard PRC-006-1, Requirement R8 and the Medium VRF for PRC-006-1, Requirement R5. NERC is directed to submit the revised VRF and VSL within 30 days of the effective date of this final rule.

J. Implementation Plan and Effective Date

96. In the NOPR, the Commission noted that NERC requests an effective date for Reliability Standards PRC-006-1 and EOP-003-2 of one year following the first day of the first calendar quarter after applicable regulatory approvals with respect to all Requirements of the proposed Reliability Standards *except* Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1. With respect to Parts 4.1 through 4.6 of Requirement R4 of PRC-006-1, NERC requests an effective date of one year following the receipt of

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generation data as required in Reliability Standard PRC-024-1,[59] but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1. The Commission sought comments about any potential reliability gaps that may occur during the development and implementation of PRC-024-1, such as how the planning coordinators will adequately determine and apply UFLS simulations and plans in the absence of generator trip settings.

Comments

97. NERC maintains that there should not be a reliability gap because planning coordinators have access to and utilize trip settings in UFLS assessments. NERC explains its proposal by noting that generator owners currently cannot be compelled to provide trip settings to planning coordinators. NERC states that the implementation schedule defers a compliance obligation for planning coordinators to model the trip settings until a compliance obligation for generator owners to provide these settings exists.

98. EEI believes that a reliability gap will exist until draft Reliability Standard PRC-024-1 is approved, but it believes that the gap is minor and manageable. EEI agrees with NERC that information that will be mandated in PRC-024-1 is already supplied through mutual cooperation between entities. EEI states that the Commission might

[59] Draft Reliability Standard PRC-024-1 addresses "Generator Performance During Frequency and Voltage Excursions" and is currently being developed in the NERC standard drafting process under Project 2007-09 (Generator Verification), which is one of NERC's priority projects.

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consider directing NERC to reevaluate its priority list to determine if the PRC-024-1 project is being given sufficient priority.

99. TAPS comments that planning coordinators have the ability to run UFLS simulations, even though modeling generator trip settings is not currently mandatory, because all significantly sized generators are included in models. TAPS contends that while some generators that trip outside of the UFLS set points may not be modeled, this will not have a significant impact on the reliability of the bulk electric system.

Commission Determination

100. The Commission approves the implementation plan and effective dates of Reliability Standards PRC-006-1 and EOP-003-2. We agree with EEI that there is a reliability gap given the lack of mandatory requirements for providing generator trip settings, which will continue until draft Reliability Standard PRC-024-1 is approved. The Commission, however, also agrees with EEI that the gap is limited because the information mandated by PRC-024-1 is already supplied through mutual cooperation between utilities. To ensure that any gap pending implementation of PRC-024-1 remains limited, the Commission encourages the current practice of voluntarily sharing generator trip settings between entities to continue.

III. Information Collection Statement

101. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an

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agency.[60] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

102. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of Paperwork Reduction Act of 1995.[61] The Commission solicited comments on the need for and the purpose of the information contained in Reliability Standard PRC-006-1 and EOP-003-2 and the corresponding burden to implement them. The Commission received comments on specific requirements in the Reliability Standards, which we address in this final rule. However, we did not receive any comments on our reporting burden estimates.

103. This final rule approves Reliability Standards PRC-006-1 and EOP-003-2, which would replace currently effective Reliability Standards PRC-007-0, PRC-009-0, EOP-003-1 and NERC-approved Reliability Standard PRC-006-0.[62] As noted previously, Reliability Standard PRC-006-0 was never approved by the Commission, and therefore

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[60] 5 CFR 1320.11.

[61] 44 U.S.C. 3507(d)

[62] PRC-006-0 was not approved by the Commission but remained effective as a NERC-approved standard (but not mandatory or enforceable). The other three standards were approved by the Commission. *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

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has never been mandatory and enforceable. On the other hand, Reliability Standards PRC-007-0 and PRC-009-0 were approved by the Commission and are currently mandatory and enforceable. Because Proposed Reliability Standard PRC-006-1 incorporates the requirements from Reliability Standards PRC-006-0, PRC-007-0, and PRC-009-0 some of the existing requirements will become mandatory and enforceable (where previously they were voluntary), while others continue to be so. To properly account for the burden on respondents, the Commission will treat the burden resulting from NERC-approved Reliability Standard PRC-006-0 as essentially new to the industry, even though it is likely that most applicable entities have already been complying.[63]

104. The reporting requirements in Reliability Standard EOP-003-2 are virtually the same as those in currently effective Reliability Standard EOP-003-1. The difference is that Reliability Standard EOP-003-2 eliminates balancing authorities from Requirements R2 and from Measure M1.[64] This requirement and measure deal with establishing and documenting automatic load shedding plans.

105. Public Reporting Burden: Our estimate below regarding the number of respondents is based on the NERC compliance registry as of July 29, 2011. According to

[63] This statement is made because currently effective Reliability Standards PRC-007-0 and PRC-009-0 required UFLS entities to follow the UFLS program implemented by Reliability Standard PRC-006-0. Therefore, it is likely that entities have already been following the requirements contained in Reliability Standard PRC-006-0.

[64] Balancing authorities are also removed from Requirements R4 and R7, but these do not have reporting requirements associated with them.

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the NERC compliance registry, there are 72 planning coordinators and 126 balancing authorities. The individual burden estimates are based on the time needed to gather data, run studies, and analyze study results to design or update the UFLS programs. Additionally, documentation and the review of UFLS program results by supervisors and management is included in the administrative estimations. These are consistent with estimates for similar tasks in other Commission approved standards.

PRC-006-1 (Automatic Underfrequency Load Shedding)[65]	Number of Respondents Annually (1)	Number of Responses per Respondent (2)	Average Burden Hours Per Response (3)	Total Annual Burden Hours (1)x(2)x(3)
PCs*: Design and document Automatic UFLS Program	72	1	120	8,640
PCs: Management Review of Documentation			40	2,880
PCs: Record Retention			16	1,152
Total				12,672
EOP-003-2 (Load Shedding Plans)[66]				

[65] Reliability Standard PRC-006-1 applies to both planning coordinators and to UFLS entities. However, the burden associated with the UFLS entities is not new because it was accounted for under Commission approved Reliability Standards PRC-007-0 and PRC-009-0.

[66] Transmission operators also have to comply with Reliability Standard EOP-003-2. Since the applicable reporting requirements (and associated burden) have not changed from the existing standard, these entities are not included here.

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Removal of BAs* from Reporting Requirements in R2 and M1 (Burden Reduction)	126	1	Reporting	-10	-1260
			Record Retention	-1	-126
Total					-1,386
Net Change in Burden (Total Annual Hours for Collection)					11,286

*PC=Planning Coordinator; BA=Balancing Authority

Total Net Annual Cost (Reporting + Record Retention)[67]: = $1,414,656 - $154,728 = $1,259,928.

- Total Reporting Cost for Planning Coordinators: = 11,520 hours @ $120/hour = $1,382,400.
- Total Record Retention Cost for Planning Coordinators: 1,152 hours @ $28/hour = $32,256.
- Total Reporting and Record Retention Cost Savings for Balancing Authorities: = (1,260 hours @ $120/hour) + (126 hours @ $28/hour) = $154,728.

Title: Mandatory Reliability Standards for the Bulk-Power System

Action: Proposed Collection FERC-725A.

OMB Control No.: 1902-0244.

[67] The hourly reporting cost is based on the cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

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Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: This Final Rule approves the requested modifications to Reliability Standards pertaining to automatic underfrequency load shedding. The Reliability Standards help ensure the reliable operation of the bulk electric system by arresting declining frequency and assisting recovery of frequency following system events leading to frequency degradation.

Internal Review: The Commission has reviewed the Reliability Standards and made a determination that its action is necessary to implement section 215 of the FPA. These requirements, if accepted, should conform to the Commission's expectation for UFLS programs as well as procedures within the energy industry.

106. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

107. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov.

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Comments submitted to OMB should include Docket Number RM11-20 and OMB Control Number 1902-0244.

IV. Environmental Analysis

108. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[68] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[69] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

109. The Regulatory Flexibility Act of 1980 (RFA)[70] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a

[68] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[69] 18 CFR 380.4(a)(2)(ii).

[70] 5 U.S.C. 601-612.

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small business.[71] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[72]

110. Reliability Standard PRC-006-1 establishes design, assessment, and documentation requirements for automatic UFLS programs. It will be applicable to planning coordinators and entities that are responsible for the ownership, operation, or control of UFLS equipment. Reliability Standard EOP-003-2 removes balancing authorities from having to comply with Requirement R2 and Measure M1 of the standard. Comparison of the NERC compliance registry with data submitted to the Energy Information Administration on Form EIA-861 indicates that perhaps as many as 8 small entities are registered as planning coordinators and 18 small entities are registered as balancing authorities. The Commission estimates that the small planning coordinators to whom the Reliability Standard will apply will incur compliance and recordkeeping costs of $157,184 ($19,648 per planning coordinator) associated with the Standard's requirements. The small balancing authorities will receive a savings of $154,728 ($8,596 per balancing authority). Accordingly, Reliability Standards PRC-006-1 and EOP-003-2

[71] 13 CFR 121.101.

[72] 13 CFR 121.201, Sector 22, Utilities & n.1.

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should not impose a significant operating cost increase or decrease on the affected small entities.

111. Based on this understanding, the Commission certifies that these Reliability Standards will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VI. Document Availability

112. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington DC 20426.

113. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

114. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

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VII. Effective Date and Congressional Notification

115. These regulations are effective [insert date 60 days from publication in Federal Register]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of subjects in 18 CFR Part 40

Electric power; Electric utilities; Reporting and record keeping requirements.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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Appendix
Commenters

Abbreviation	Commenter
Dominion	Dominion Resources Services, Inc.
EEI	Edison Electric Institute
EPSA	Electric Power Supply Association
FRCC	Florida Reliability Coordinating Council, Inc.
G&T Cooperatives	Associated Electric Cooperative, Inc.; Basin Electric Power Cooperative; and Tri-State Generation and Transmission Association, Inc.
KCP&L	Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company
MISO	Midwest Independent Transmission System Operator, Inc.
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator, Inc.
PSEG	Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC
SWPA	Southwestern Power Administration
TAPS	Transmission Access Policy Study Group
Wisconsin Electric	Wisconsin Electric Power Company

Document Content(s)

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For the Nuclear Regulatory Commission.

Annette L. Vietti-Cook,

Secretary of the Commission.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM11–20–000; Order No. 763]

Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Under section 215 of the Federal Power Act (FPA), the Federal Energy Regulatory Commission (Commission) approves Reliability Standards PRC–006–1 (Automatic Underfrequency Load Shedding) and EOP–003–2 (Load Shedding Plans), developed and submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Commission. In addition, pursuant to section 215(d)(5) of the FPA, the Commission directs NERC to develop a modification to clarify the intent of one provision of the Reliability Standard. The approved Reliability Standards establish design and documentation requirements for automatic underfrequency load shedding programs that arrest declining frequency and assist recovery of frequency following system events leading to frequency degradation. The Commission approves, with modifications, the related Violation Risk Factors and Violation Severity Levels, implementation plan, and effective date proposed by NERC. The Commission also approves the regional variance for the Western Electricity Coordinating Council in Reliability Standard PRC–006–1.

DATES: *Effective Date:* This rule will become effective July 10, 2012.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris.

Final Rule

Issued May 7, 2012.

1. Under section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standards PRC–006–1 (Automatic Underfrequency Load Shedding) and EOP–003–2 (Load Shedding Plans). In addition, pursuant to section 215(d)(5) of the FPA, the Commission directs the North American Electric Reliability Corporation (NERC) to develop a modification to clarify the intent of one provision of the Reliability Standard. The approved Reliability Standards were developed and submitted for approval to the Commission by NERC, the Commission certified Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. The approved Reliability Standards establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs, which are meant to arrest declining frequency and assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

2. The Commission approves, with modifications, the related Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), implementation plan, and effective date proposed by NERC. The Commission approves the retirement of the currently-effective Reliability Standards PRC–007–0, PRC–009–0, and EOP–003–1, and the NERC-approved Reliability Standard PRC–006–0. Further, the Commission approves the regional variance for the Western Electricity Coordinating Council (WECC) in PRC–006–1.

I. Background

A. Mandatory Reliability Standards

3. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[2]

4. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO [3] and, subsequently, certified NERC as the ERO.[4] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standards PRC–007–0, PRC–009–0, and EOP–003–1.[5] The Commission neither approved nor remanded NERC-approved Reliability Standard PRC–006–0 in Order No. 693,[6] which required regional reliability organizations to develop, coordinate, document and assess UFLS program design and effectiveness at least every five years. The Commission determined neither to approve nor remand this ''fill-in-the-blank'' Reliability Standard because the regional procedures had not been submitted, and the Commission held that it would not propose to approve or remand PRC–006–0 until the ERO submitted the additional information.[7]

B. NERC Petition

5. On March 31, 2011, NERC filed a petition seeking Commission approval of Reliability Standards PRC–006–1 (Automatic Underfrequency Load Shedding) and EOP–003–2 (Load Shedding Plans), and the concurrent retirement of the currently-effective Reliability Standards PRC–007–0, PRC–009–0, and EOP–003–1, and the NERC-approved Reliability Standard PRC–006–0. The petition, as amended on May 17, 2011, states that PRC–006–1 establishes design and document requirements for UFLS programs that arrest declining frequency and assist recovery of frequency following system events leading to frequency degradation.[8] The petition states that EOP–003–2 makes minimal changes to EOP–003–1 by removing references to UFLS, which NERC describes as

[1] 16 U.S.C. 824o (2006).

[2] 16 U.S.C. 824o(e).

[3] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g,* Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[4] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g and compliance,* 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

[5] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 603, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[6] *Id.* P 1479.

[7] *Id.* PP 1477, 1479.

[8] The Notice of Proposed Rulemaking in this docket included a primer on UFLS programs generally. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards,* Notice of Proposed Rulemaking, 76 Fed. Reg. 66,220 (October 26, 2011), FERC Stats. & Regs. ¶ 32,682 (2011).

redundant in light of PRC–006–1, and instead focuses EOP–003–2 on undervoltage conditions.

6. The petition states that Reliability Standard PRC–006–1 achieves a specific reliability goal by establishing design and documentation requirements for automatic UFLS programs to arrest declining frequency, assist recovery of frequency following underfrequency events, and provide last resort system preservation measures. Further, the petition states that PRC–006–1 contains a technically sound method to achieve its reliability goal by establishing a framework for developing, designing, assessing and coordinating UFLS programs, and that PRC–006–1 is clear and unambiguous regarding what is required and who is required to comply with the Reliability Standard.

7. In the petition, NERC proposes VRFs and VSLs, an implementation plan, and an effective date. The petition requests an effective date for Reliability Standards PRC–006–1 and EOP–003–2 of one year following the first day of the first calendar quarter after applicable regulatory approvals with respect to all Requirements of the Reliability Standards *except* Parts 4.1 through 4.6 of Requirement R4 of PRC–006–1. With respect to Parts 4.1 through 4.6 of Requirement R4 of PRC–006–1, NERC requests an effective date of one year following the receipt of the generation data that would be required in draft Reliability Standard PRC–024–1 [9] but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC–006–1.

C. Notice of Proposed Rulemaking

8. On October 20, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve Reliability Standards PRC–006–1 and EOP–003–2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission proposed to approve PRC–006–1 and EOP–003–2 because the UFLS program addressed in the Reliability Standards is important to arresting declining frequency and assisting recovery of frequency following system events that lead to system instability, which can result in a blackout. The NOPR stated that the Reliability Standards are necessary for reliability because UFLS is used in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island. The NOPR concluded that PRC–006–1, in conjunction with the conforming changes to EOP–003–2, provides last resort Bulk-Power System preservation measures by establishing the first national Reliability Standard of common performance characteristics that all UFLS programs must meet.

9. The NOPR proposed to approve the related VRFs and VSLs, implementation plan, and effective date proposed by NERC. The NOPR also proposed to approve the regional variance for WECC in Reliability Standard PRC–006–1.

10. While proposing to approve Reliability Standards PRC–006–1 and EOP–003–2, the NOPR addressed or sought comments on the following issues: (A) Impact of resources not connected to the bulk electric system; (B) validation of power system models used to simulate UFLS programs; (C) scope of UFLS events assessments; (D) impact of generator owner trip settings outside of the UFLS program; (E) UFLS program coordination with other protection systems; (F) identification of island boundaries in UFLS programs; (G) automatic load shedding in PRC–006–1 and manual load shedding in EOP–003–2; (H) elimination of balancing authority responsibilities in EOP–003–2; and (I) the ''Lower VSL'' for Requirement R8 and the ''Medium'' VRF for Requirement R5 of PRC–006–1.

11. In response to the NOPR, comments were filed by NERC and 12 interested persons.[10] The comments generally support the approval of Reliability Standards PRC–006–1 and EOP–003–2. The comments also provide information responsive to the questions raised in the NOPR. In the discussion below, we address the questions raised in the NOPR in light of the comments.

II. Discussion

12. The Commission approves Reliability Standards PRC–006–1 and EOP–003–2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission's approval is consistent with the broad support for the Reliability Standards expressed in the comments. The UFLS program addressed in Reliability Standard PRC–006–1 is important to arresting declining frequency and assisting recovery of frequency following system events that lead to system instability, which can result in a blackout. Accordingly, the Reliability Standard is necessary for reliability because UFLS is used in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island. PRC–006–1, in conjunction with the conforming changes to EOP–003–2, provides last resort Bulk-Power System preservation measures by establishing the first national Reliability Standard of common performance characteristics that all UFLS programs must meet. For the same reasons, we approve the regional variance for WECC in PRC–006–1. We also approve the VRFs and VSLs designated for the requirements of the Reliability Standards, with modifications, and the implementation plan and effective date, as proposed by NERC.

13. We address below the following issues raised in the NOPR in light of the comments received: (A) Impact of resources not connected to the bulk electric system; (B) validation of power system models used to simulate UFLS programs; (C) scope of UFLS events assessments; (D) impact of generator owner trip settings outside of the UFLS program; (E) UFLS program coordination with other protection systems; (F) identification of island boundaries in UFLS programs; (G) automatic load shedding in PRC–006–1 and manual load shedding in EOP–003–2; (H) elimination of balancing authority responsibilities in EOP–003–2; and (I) the ''Lower VSL'' for Requirement R8 and the ''Medium'' VRF for Requirement R5 of PRC–006–1. Regarding the last issue, the Commission directs NERC to modify the ''Lower VSL'' for Requirement R8 of PRC–0061 and the ''Medium'' VRF for Requirement R5 of PRC–006–1 consistent with the discussion below.

A. Impact of Resources Not Connected to Bulk Electric System Facilities

14. Requirement R2 of Reliability Standard PRC–006–1 requires planning coordinators to identify islands to serve as a basis for designing UFLS programs. Requirement R3 addresses performance characteristics for UFLS programs. Requirement R4 requires each planning coordinator to conduct and document the assessment of its UFLS design and determine if the UFLS program meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulations outlined in Requirement R4 all concern individual generating units greater than 20 MVA gross nameplate rating or generating plants/facilities greater then 75 MVA ''connected to the bulk electric system.''

[9] Draft Reliability Standard PRC–024–1 addresses ''Generator Performance During Frequency and Voltage Excursions'' and is currently being developed in the NERC standard drafting process.

[10] A list of the commenters is provided in the Appendix.

15. In the NOPR, the Commission stated that some generation meeting the 20 MVA and 75 MVA criteria in Reliability Standard PRC–006–1, Requirement R4 would not be modeled pursuant to Requirement R4 because it is not connected to bulk electric system facilities. The Commission explained that a resource not directly connected to the bulk electric system may serve load designed to be shed in a UFLS program. The Commission expressed concern that failure to account for resources not directly connected to the bulk electric system could result in planning coordinators being unaware of how those resources respond to underfrequency conditions. The Commission stated that if a planning coordinator is unaware of how these resources respond, it may plan to shed more load than is necessary for an area's frequency to return to normal, which could cause an unintended overfrequency condition if the plan is carried out in the operating timeframe. These conditions, in turn, could cause the UFLS program to violate the performance characteristics specified in Requirement R3 of PRC–006–1. The Commission sought comment as to whether and how all resources required for the reliable operation of the bulk electric system, including resources not connected to bulk electric system facilities, are considered in the development of UFLS programs under Requirements R3 and R4 of PRC–006–1.

Comments

16. NERC agrees with the NOPR that failing to model qualifying generation not directly connected to the bulk electric system could affect the simulated frequency response. NERC, however, clarifies that Reliability Standard PRC–006–1 does not ''establish parameters for what resources are modeled in [] simulations'' and that ''power system models used in UFLS assessments are generally the same models used in transmission planning assessments, which include models of all generation units and plants that meet the threshold size requirements even those not connected directly to the Bulk Electric System.'' [11] In addition, NERC states that a standard authorization request is under development as part of the ''second phase'' of the project to revise the definition of bulk electric system, and information developed as part of that project could be used to assess whether any changes are needed to PRC–006–1.

17. EEI, TAPS, MISO, and FRCC maintain that the vast majority of qualifying generation is accounted for in Reliability Standard PRC–006–1. EEI comments that bulk electric system resources account for the ''vast majority of resources within all interconnections'' and supports the standard drafting team's belief that the Reliability Standard generally captures about 95 percent of utility-owned installed capacity.[12] While EEI acknowledges that there are a small number of unaccounted for generation resources that meet the qualifying criteria, EEI comments that what is captured is sufficient for assessing reliable operation of the bulk electric system. EEI also maintains that planning coordinators already consider other resources as appropriate.

18. TAPS states that the ''great majority'' of generators are not set to trip before the underfrequency set points, so they will be available for UFLS programs.[13] TAPS contends that the only generators of concern are those that: (1) Do not meet Reliability Standard PRC–006–1's size and connection criteria; (2) trip prior to underfrequency set points; and (3) are dispatched during underfrequency events because they are not required to be modeled under PRC–006–1. TAPS maintains that the number of generators that meet these criteria is ''very small'' so that modeling them would have an ''infinitesimal reliability benefit,'' not improving the overall accuracy of the UFLS program design and not justifying the additional costs.[14]

19. MISO states that UFLS simulations should not be required to include all generation that meets the 20 MVA and 75 MVA criteria in Reliability Standard PRC–006–1, Requirement R4. MISO cites the standard drafting team's belief that PRC–006–1 captures about 95 percent of utility-owned installed capacity.[15] MISO also maintains that the standard drafting team deserves deference and that simulations will always contain some degree of uncertainty.

20. FRCC states that generators that fall within the size requirements of Reliability Standard PRC–006–1 but that are not connected to bulk electric system facilities constitute a ''very small amount.'' [16] FRCC maintains that this amount is well below the error tolerance of a well-designed UFLS program and, thus, is not important.

21. SWPA states that planning coordinators, in developing UFLS programs, should consider all resources that are determined to be required for the reliable operation of the bulk electric system, regardless of whether those resources are directly connected to the bulk electric system.

22. NYISO comments that it analyzes UFLS effectiveness using a Multiregional Modeling Working Group dynamics model of the Eastern Interconnection, which includes all resources on the system regardless of bulk electric system connections.

Commission Determination

23. In the NOPR, the Commission expressed concern regarding the development of UFLS programs that fail to account for qualifying generation not directly connected to the bulk electric system. We are satisfied with the explanations provided by commenters. First, we are persuaded by NERC's explanation that Reliability Standard PRC–006–1 does not limit the resources that can be modeled in the UFLS assessments and that power system models used in UFLS assessments generally model all qualifying generation, including resources not directly connected to the bulk electric system. In summary, although PRC–006–1 does not require all of the generation that is not directly connected to the bulk electric system to be included in the modeling, the subset of these resources that are required to assure that the UFLS models are sufficient to accurately predict system performance will be included. Similarly, we accept comments from EEI, TAPS, MISO, and FRCC that PRC–006–1 requires modeling of the vast majority of qualifying generation to ensure the reliable operation of the bulk electric system.

24. Like SWPA, the Commission believes that requiring all qualifying assets to be accounted for in UFLS programs, regardless of whether they are directly or indirectly connected to the bulk electric system, is useful to ensuring the effectiveness of the programs. Not requiring applicable entities to model sufficient amounts of qualifying generation indirectly connected to the bulk electric system could result in applicable entities not knowing how those resources react during underfrequency situations, which could cause excessive load shedding in an emergency and further contribute to system instability.

25. NERC states in its comments that this issue could be further evaluated in the ''second phase'' of the project to revise the definition of bulk electric system, and that information from that project could be used as a basis for

[11] NERC Comments at 4.

[12] EEI Comments at 2–3.

[13] TAPS Comments at 4.

[14] *Id.* at 4–5.

[15] MISO Comments at 3.

[16] FRCC Comments at 2.

revising Reliability Standard PRC–006–1 if necessary.[17] Without prejudging those efforts, the Commission will not issue a directive requiring the modeling of qualifying generation not directly connected to the bulk electric system.

B. Validation of Power System Models

26. In the NOPR, the Commission stated that dynamic simulations that fail to accurately represent the power system can result in UFLS programs that are ineffective. The Commission, however, concluded that the UFLS program design requirements established in Requirement R2 of Reliability Standard PRC–006–1 and the required assessments established in Requirements R4 and R11 of PRC–006–1 are generally acceptable and include improvements over the current Reliability Standards.

Comments

27. FRCC comments that improving the accuracy of power system models used in simulating system response to forecasted system conditions is an appropriate goal, but achieving 100 percent accuracy is not practicable. EEI comments that dynamic simulations for any large power system will never be 100 percent accurate and asks the Commission not to impose any new directives which might unnecessarily increase costs to industry.

28. NYISO states that a lack of accuracy in modeling can have a significant impact on analyses of under-generated islands. Specifically, NYISO states that ''optimistic models of unit governing response can lead to invalid conclusions regarding minimum frequency and frequency recovery.'' [18] NYISO indicates that it is taking steps to improve the accuracy of modeling frequency recovery by, among other things, aligning the dynamics model to observed system response.

Commission Determination

29. The Commission accepts the comments from EEI and FRCC that power system models with 100 percent accuracy are not practicable. The Commission, however, is mindful of the consequences of inaccurate power system models and their impact on an entity's ability to accurately simulate system performance. As noted by NYISO, inaccurate models can lead to invalid conclusions which can be detrimental to the analysis and operation of the bulk electric system. At a minimum, the models should accurately predict system performance during UFLS events. Although entities may take additional steps, such as the step taken by NYISO to ensure accurate models, as stated in the NOPR, the Commission believes that the design requirements in Reliability Standard PRC–006–1 are acceptable.[19]

C. UFLS Event Assessments

1. Assessments in the Absence of Island Formation

30. Requirement R11 of Reliability Standard PRC–006–1 requires planning coordinators to conduct assessments after a ''BES islanding event results in system frequency excursion below the initializing set points of the UFLS program.''

31. In the NOPR, the Commission expressed concern that the phrase ''BES islanding event'' could be interpreted to mean that a planning coordinator only has to assess an event if it meets both of the following requirements: (1) System frequency excursions fall below the initializing set point for UFLS; and (2) bulk electric system islands form within the Interconnection. The Commission explained that, if frequency falls below the initializing UFLS set point but islands do not form (e.g., because the event was not severe enough to isolate portions of the Interconnection, or UFLS or other protection systems failed to operate properly to form islands), an assessment of the performance of the UFLS program for this event is still useful because it can determine if the UFLS program operated as expected. The Commission sought comment on what actions must planning coordinators take under Requirement R11 of PRC–006–1 if an event results in system frequency excursions falling below this initializing set point for UFLS but without the formation of a bulk electric system island.

Comments

32. In its comments, NERC states that ''[a]lthough PRC–006–1 does not prescribe an analysis for [the non-islanding scenario identified in the NOPR], activating UFLS during an Interconnection-wide event would involve a significant loss of generation and analysis would be performed under the NERC Event Analysis program or the NERC Rules of Procedure, depending on the severity of the event.'' [20] NERC further states that the ''activation of UFLS, while highly unlikely, would be a significant event requiring assessment of several aspects of system frequency, including system Frequency Response, equipment performance, and coordination of protection and control systems, in addition to the assessment of UFLS program operation.'' [21] Ultimately, NERC agrees that an assessment of the performance of UFLS, even in the absence of island formation, is useful.

33. EEI and MISO agree with NERC that Requirement R11 of Reliability Standard PRC–006–1 requires both conditions (i.e., frequency excursion and islanding) to be met. MISO agrees with the NOPR that an analysis of excursions without islanding is useful. However, MISO and EEI comment that such an analysis is outside the scope of the Reliability Standard. MISO, quoting the NOPR, states that UFLS ''is designed for use in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed.'' [22] Accordingly, MISO argues that a UFLS program ''can only truly be assessed in light of its performance after an island has formed.'' [23] In addition, such assessments are costly, time consuming and resource intensive, according to MISO. EEI maintains that entities ''broadly perform assessments of lesser events as they deem necessary.'' [24] EEI contends that such assessments are not required in PRC–006–1 because ''to do so would go beyond the intent of the program which is the design of UFLS programs.'' [25] Instead, EEI notes that applicable entities normally conduct operational assessments regularly, and if an entity identifies a problem the entity would report the matter as a misoperation with an obligation to remediate. EEI also points to the draft NERC Event Analysis Process [26] and its application to what EEI describes as ''underfrequency events of a lesser level'' (i.e., events resulting in load shedding with a loss of load of 100 MW or more).[27] EEI contends that the Commission's concerns regarding analysis of lesser events will be satisfied once the NERC Event Analysis Process is finalized.

34. SWPA states that it is reasonable for planning coordinators to request and analyze event data in the absence of island formation to assess the performance of UFLS programs. Specifically, SWPA comments that

[17] NERC Comments at 5.

[18] NYISO Comments at 3.

[19] NOPR, FERC Stats & Regs, ¶ 32,682 at P 34.

[20] NERC Comments at 6.

[21] *Id.*

[22] MISO Comments at 4 (*citing* NOPR, FERC Stats & Regs. 32,682 at P 35).

[23] *Id.*

[24] EEI Comments at 5.

[25] *Id.*

[26] We understand the NERC Event Analysis Process to be the same as the NERC Event Analysis program referenced in NERC's comments.

[27] *Id.*

''[t]he assessment of a UFLS event during varying system conditions caused by generator outages, transmission outages, and various maintenance activities, provides an opportunity to discover the impacts of these activities on the expected outcomes described in the plan.'' [28]

Commission Determination

35. NERC clarifies that Requirements R11 and R12 of Reliability Standard PRC–006–1 are triggered when system frequency excursions fall below the initializing set points for UFLS programs and bulk electric system islands form within Interconnections.[29]

36. The Commission agrees with commenters that it would be useful to have an analysis of system frequency excursions to assess the performance of UFLS programs even in the absence of island formation.[30] To that end, we agree with NERC that underfrequency events that result in the initializing of the UFLS set point, even in the absence of island formation, would be analyzed under provisions contained in the NERC Rules of Procedure and the NERC Event Analysis program.[31]

2. Coordination of Assessments and Results

37. Requirements R5 and R13 of Reliability Standard PRC–006–1 provide flexibility in coordinating UFLS design programs and event assessments among planning coordinators whose areas fall within the same island or whose areas are affected by the same event. In the NOPR, the Commission sought comments on whether differences in assessments between planning coordinators should be reported to reliability coordinators for resolution in the event that the process identified in PRC–006–1 does not resolve the differences.

Comments

38. NERC, MISO, and EEI comment that reliability coordinators should not be tasked with resolving differences between planning coordinator event assessments. NERC states that differences between planning coordinator event assessments should not be reported to reliability coordinators because: (1) Reliability coordinator's wide-area view may not coincide with island boundaries; (2) reliability coordinators may have conflicts of interest; (3) reliability coordinators may not have the tools to resolve the differences; and (4) reliability coordinators work in a real-time operating environment, which makes them ill-suited to resolve disputes among planning coordinators.

39. MISO and EEI comment that event assessment differences should not be reported to reliability coordinators because planning coordinators are better positioned to reconcile differences. MISO notes that in some cases where an applicable entity is both a reliability coordinator and planning coordinator (as is the case with MISO), there would be a conflict of interest. Further, MISO maintains that referring disputes to reliability coordinators imposes additional costs with little to no benefit. MISO and EEI also contend that event assessment differences do not pose a risk to the reliability of the bulk electric system, with EEI noting that such differences are ''a result of legitimate engineering and regional practices and processes.'' [32] At most, EEI suggests that reliability coordinators might be used as informal facilitators.

40. SWPA states that a clear resolution process is necessary and that referring disputes to reliability coordinators is a reasonable consideration.

Commission Determination

41. The Commission is persuaded by the comments of NERC, MISO, and EEI that differences between planning coordinator event assessments should not be referred to reliability coordinators for resolution. We share the concern of NERC, MISO, and EEI that referring disputes to reliability coordinators may create conflicts of interest because a planning coordinator may also serve as a reliability coordinator. We agree, however, with SWPA that disputes between planning coordinator event assessments should be resolved. Therefore, the Commission expects planning coordinators to work in good faith including, as appropriate, use of third parties to resolve disputes concerning event assessments. If the Commission finds that these disputes are not being resolved, the Commission may consider adoption of an appropriate process to ensure resolution of the disputes.

3. *Assessment Timeline for Completion*

42. Requirement R11 of Reliability Standard PRC–006–1 requires planning coordinators to perform island event assessments within one year of an event. If the planning coordinator identifies program deficiencies, Requirement R12 of PRC–006–1 requires planning coordinators to conduct and document UFLS design assessments, which are meant to consider the deficiencies, within two years of an event.

43. In the NOPR, the Commission expressed concern that this time frame could be too long because island event assessments and consideration of deficiencies could reasonably be done in a shorter time frame. Moreover, the Commission noted that under PRC–006–1, deficiencies could remain within a UFLS program for two years from an event exposing the Bulk-Power System to instability, uncontrolled separation and cascading outages should a frequency event occur that the UFLS program mishandles. The Commission sought comments on the basis for the two-year time frame and clarification as to how soon after an event would an entity need to implement corrections in response to any deficiencies identified in the event assessment under Requirement R11 of PRC–006–1.

Comments

44. NERC comments that, while some events can be assessed in less time, one year is a realistic time-frame to assess performance for complex events and two years is a realistic time-frame to address identified deficiencies. NERC states that ''the amount of time that a UFLS entity has to implement corrections will be established by the Planning Coordinator, as specified in Requirement R9 of PRC–006–1 * * * [and] [t]he time allotted for corrections will depend on the extent of the deficiencies identified.'' [33]

45. EEI, MISO, and G&T Cooperatives support the timelines in Reliability Standard PRC–006–1. MISO maintains that event assessments are time and resource intensive and must not be rushed. EEI, MISO, and G&T Cooperatives state that planning coordinators can complete analyses of less complex events before the two-year deadline, but they need the maximum

[28] SWPA Comments at 3.

[29] NERC Comments at 6.

[30] NERC Comments at 5; MISO Comments at 4; SWPA Comments at 3.

[31] NERC Comments at 6. Section 807 of the NERC Rules of Procedure addresses ''Analysis of Major Events'' and Section 808 addresses ''Analysis of Off-Normal Events, Potential System Vulnerabilities, and System Performance.'' Separately, the NERC Event Analysis program, which is not incorporated in the NERC Rules of Procedure, as of this time is still under development. Compliance with the NERC Rules of Procedure is mandatory pursuant to section 39.2(b) of the Commission's regulations and is enforceable by the Commission pursuant to section 39.9 of the Commission's regulations. 18 CFR 39.2(b) (''All entities subject to the Commission's reliability jurisdiction under paragraph (a) of this section shall comply with applicable Reliability Standards, the Commission's regulations, and applicable Electric Reliability Organization and Regional Entity Rules made effective under this part.''); 18 CFR 39.9.

[32] EEI Comments at 6.

[33] NERC Comments at 8.

allowable time to finish analyses of complex events. With respect to the time allowed for correcting problems, EEI comments that any deadline in a requirement would be difficult to enforce and would not improve reliability given the variable nature of possible deficiencies.

46. SWPA states that an applicable entity may need to implement corrections that require complex procurement or acquisition processes, and such contracts can be complex, involving many required decisions and actions. Given these complexities, SWPA maintains that four years after event actuation is a reasonable deadline to implement corrections.

Commission Determination

47. Based on the comments, the Commission is persuaded that two years to complete design assessments pursuant to Reliability Standard PRC–006–1 is appropriate. As noted by EEI, MISO, and G&T Cooperatives, assessments of complex events can be time and resource intensive. Thus, we agree that two years is a reasonable maximum allowable time for completion of design assessments. However, we agree with commenters that efforts should be made to complete assessments of less complex events before the two-year maximum allowable period.[34]

48. In response to the Commission's concern that Reliability Standard PRC–006–1 does not specify how soon after an event would an entity need to implement corrections in response to any deficiencies identified in the event assessment under Requirement R11 of PRC–006–1, NERC stated in its comments that:

> The amount of time that a UFLS entity has to implement corrections will be established by the Planning Coordinator, as specified in Requirement R9 of PRC–006–1. The time allotted for corrections will depend on the extent of the deficiencies identified. The schedule specified by the Planning Coordinator will consider the time necessary for budget planning and implementation, recognizing that operating and maintenance budgets normally will not be sufficient to address major revisions and allowances will be necessary for inclusion of approved changes in budgeting cycles.[35]

Requirement R9 of PRC–006–1 states:

> R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets.

[34] EEI Comments at 7; MISO Comments at 6.

[35] NERC Comments at 8.

[VRF:High][Time Horizon: Long-term Planning]

Notwithstanding NERC's comments, the Commission is not persuaded that Requirement R9 requires corrective action in accordance with a schedule established by the planning coordinator. Based on its comments, however, NERC has expressed no opposition to such a requirement. We accept NERC's comments that Requirement R9 requires a schedule established by the planning coordinator, but NERC's reading of Requirement R9 should be made clear in the Requirement itself. Accordingly, we direct NERC to make that requirement explicit in future versions of the Reliability Standard. Within 30 days of the effective date of this Final Rule, NERC is directed to submit a compliance filing indicating how it plans to comply with this directive and a deadline for compliance.

D. Generator Owner Trip Settings Outside of the UFLS Program

49. In the NOPR, the Commission stated that Requirements 4.1 through 4.7 of Reliability Standard PRC–006–1 are intended to capture the effects of generators that trip prior to UFLS initiation. While agreeing that planning coordinators should consider generators that trip prior to underfrequency set points when developing their UFLS programs, the Commission sought comments on how generation losses outside of the UFLS set points (*i.e.,* generators having trip settings prior to the UFLS underfrequency set points) should be accounted for in UFLS programs (*e.g.,* generator owners who trip outside of the UFLS set points could procure load to shed to account for the loss in generation).

Comments

50. NERC, EEI, TAPS, Dominion, FRCC and EPSA oppose requiring generator owners to procure load to shed for generators that trip outside of the UFLS set points. NERC states that it is appropriate for planning coordinators to consider generators that trip outside of the UFLS set points when designing UFLS programs, but it is inappropriate for planning coordinators to determine whether mitigation is necessary and who will be responsible for providing mitigation.

51. EEI states that Reliability Standard PRC–006–1, Requirement R4 requires that all resources included in the UFLS program that operate outside the specified trip settings be factored in to the dynamic simulation models used to develop the program. EEI further notes that, while there is no formal obligation for generator owners to supply trip setting data to planning coordinators, this information is shared. Unlike modeling generators that trip outside of the UFLS set points, EEI maintains that the issue of procuring load to shed to compensate for such trips is outside the scope of PRC–006–1.

52. TAPS comments that generators that trip prior to underfrequency set points are separately modeled under Reliability Standard PRC–006–1 and that this is the correct approach to account for such generators. TAPS opposes requiring generator owners who trip outside of the UFLS set points to procure load to shed to account for the loss in generation. TAPS objects to a ''one-size-fits all market/contractual solution'' given the absence of a demonstrable reliability problem and the market power concerns it might create.[36] TAPS maintains that in some small islands it may be impossible to procure the necessary load to shed.

53. Dominion states that generator owners whose generators trip prior to UFLS set points should not be required to procure load to shed. Dominion contends that such a scheme could be extremely difficult to design and coordinate, and Dominion is unaware of any distribution provider or transmission owner tariff that offers such a service.

54. FRCC maintains that a small minority of generator underfrequency protection settings are above the minimum UFLS frequency set points and that in many cases any conflicts can be resolved by reexamination of the technical basis for the generator's underfrequency protection. FRCC also states that requiring generator operators to procure load to shed would be technically impossible, and there is no market for compensatory, assignable UFLS to make generator contracts for load shedding feasible.

55. EPSA states that planning coordinators should consider generators that trip prior to underfrequency set points when collecting information and developing their UFLS programs. EPSA maintains, however, that requiring planning coordinators to account for generators that trip prior to the UFLS set points presupposes that there is a material amount of generator losses occurring. EPSA believes that implementation of Reliability Standard PRC–006–1 will allow planning coordinators to gather information to determine the amount of losses, which can then be used to decide whether generator losses need to be accounted for. EPSA states that if generator losses are found to be a material concern that

[36] TAPS Comments at 7.

needs to be accounted for, the Commission should consider that: (1) Generator owners do not and cannot play an active role in UFLS program decisions; (2) generator owners do not determine the set points for their generation; and (3) the NERC process should not be used to influence market decisions and competitiveness.

56. SWPA states that the design assessment in Requirement R4 of Reliability Standard PRC–006–1 addresses the modeling of generators having trip settings prior to the UFLS set points but that the Reliability Standard does not address how planning coordinators would resolve the need for supplemental UFLS. SWPA maintains that PRC–006–1 should include a requirement for planning coordinators to identify the UFLS entity that needs to provide supplemental UFLS, the basis for the identification, and coordination of this information with those entities and affected generator owners.

57. NYISO states that it conducts an annual survey of all generator owners within the New York Control Area for their UFLS trip setting and addresses those that have settings outside the UFLS program range established by the Northeast Power Coordinating Council (NPCC). NYISO states that it conducts a UFLS simulation that excludes non-conforming generation and a separate simulation that incorporates 260 MW of compensatory load shedding with tripping of non-conforming generation.

Commission Determination

58. Based on the comments, the Commission is persuaded to take no action to require compensation for generation losses outside of the UFLS set points (i.e., generators having trip settings prior to the UFLS underfrequency set points). Reliability Standard PRC–006–1 is an improvement because it requires planning coordinators to consider generators that trip outside of the UFLS set points when modeling and designing UFLS programs. We are persuaded by NERC's comments that it is appropriate for planning coordinators to consider generators that trip outside of the UFLS set points when designing UFLS programs, but it is inappropriate for planning coordinators to determine whether mitigation is necessary and who will be responsible for providing mitigation. For these reasons, we take no action to modify the Reliability Standard.

E. UFLS Program Coordination With Other Protection Systems

59. In the NOPR, the Commission stated that an integrated approach to the coordination of all types of protection systems (e.g., UFLS, undervoltage load shedding [37]), internally and externally to an entity's area, is required to be responsive to the 2003 Blackout Report.[38] The Commission noted that, while Reliability Standard PRC–006–1 requires coordination of UFLS programs among planning coordinators in Requirements R5, R7, and R13, it does not appear to capture the same level of coordination with other protection systems as in Requirement R1.2.8 of PRC–006–0, which was approved by the NERC Board of Trustees but left pending in Order No. 693.[39] The Commission sought comments on whether and how coordination with other protection systems is or is not achieved under the new requirements.

Comments

60. NERC states that Requirement R1.2.8 of PRC–006–0 includes a broad mandate and that the intent was to replace it with more specific requirements that are clear and measurable. NERC contends that Requirements R3, R4, and R10 of Reliability Standard PRC–006–1 include requirements for the coordination of UFLS programs with specific protections that ''are part of or could impact the UFLS program.'' [40] EEI and G&T Cooperatives likewise believe that Requirement R1.2.8 is vague, while PRC–006–1 contains the specificity to ensure that UFLS programs are adequately designed and coordinated. G&T Cooperatives maintains that coordination of UFLS and UVLS programs is already provided for in PRC–010–0, Requirement R1.1.1.

61. FRCC states that there is seldom a need to coordinate UFLS with UVLS and that the Reliability Standard PRC–006–1 correctly identifies the protection systems that entities should coordinate with UFLS programs. FRCC contends that the potential for interaction between UFLS and UVLS programs is minimal given that UVLS schemes are not deployed throughout an interconnection and are, instead, deployed in specific locations that may be exposed to low voltage for a specific contingency. NYISO likewise states that, due to the distributed nature of UFLS, there should not be any significant interaction between fault clearing protections and UFLS and that under-voltage inhibition of relays is not expected to interfere with UFLS programs.

Commission Determination

62. With regard to our concern raised in the NOPR regarding the coordination of UFLS with other protection systems, we are persuaded by NERC's comments that Reliability Standard PRC–006–1 provides an adequate level of coordination between the UFLS program and specific protection systems and controls that NERC identifies as part of, or could impact, the UFLS program.[41]

63. We are persuaded by NERC comments that ''Requirements R3, R4, and R10 of PRC–006–1 address coordination of the UFLS program with other protection and control systems * * * includ[ing] generator protections that could respond to frequency and voltage excursions, automatic Load restoration, and equipment switching that may be included in the UFLS program to control voltage.'' [42] Specifically, planning coordinators are to coordinate expected generation performance during underfrequency events and generator trip settings under PRC–006–1, Requirements R3 and R4.[43] To satisfy PRC–006–1, Requirement R10, transmission owners must provide the necessary automatic switching of elements as directed by the planning coordinator in the UFLS program and schedule.[44] To maintain the required system restoration capability required by PRC–006–1, Requirement R10, transmission owners must coordinate other protection system components with the established UFLS program components.

64. Additionally, the Commission notes that currently-effective Reliability Standard PRC–001–1 (System Protection Coordination) ensures system protection coordination for protection systems.[45] The Commission believes that this level

[37] Undervoltage load shedding (UVLS) is automatic load-shedding that sheds load to prevent local area voltage collapse. *See U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, at 92 (Apr. 2004) (Blackout Report), available at *http://www.ferc.gov/industries/electric/indus-act/reliability/blackout.asp*.

[38] Blackout Report at 159.

[39] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1477, 1479.

[40] NERC Comments at 9.

[41] It may be appropriate to address an integrated approach to the coordination of all protections systems, as recommended by the Blackout Report, but that issue is outside the scope of this proceeding addressing Reliability Standard PRC–006–1.

[42] NERC Comments at 9.

[43] *Id.* at 9–10.

[44] *Id.* at 11.

[45] Reliability Standard PRC–001–1, Requirements R1 and R3.

of coordination between UFLS programs and other specific protection systems is adequate.

F. Identification of Island Boundaries

65. Requirement R1 of Reliability Standard PRC–006–1 directs planning coordinators to develop criteria to select areas that may form islands based on historical events and system studies. Historical events and system studies provide planning coordinators with the data necessary to determine where islands will occur based on the physics of the system. Requirement R2.3 of PRC–006–1 allows planning coordinators to ''adjust the island boundaries to differ from the Regional Entity area boundaries by mutual consent where necessary'' to preserve contiguous island boundaries that better reflect simulations.

66. In the NOPR, the Commission agreed with the premise behind Requirement R1, which requires identifying island boundaries based on where they are likely to occur as opposed to following rigid Regional Entity area boundaries, because it should result in more effective UFLS programs. The NOPR also noted that NERC, in its petition, stated that Reliability Standard PRC–006–1 allows planning coordinators to ''select islands including interconnected portions of the bulk electric system in adjacent Planning Coordinator areas and Regional Entity areas, without the need for coordinating this selection with Planning Coordinators in neighboring regions.'' [46] The Commission observed, however, that Requirement R2.3 of PRC–006–1 requires ''mutual consent'' to adjust island boundaries from Regional Entity boundaries. The Commission sought clarification concerning the required degree of cooperation and/or ''mutual consent'' between planning coordinators under the proposed Reliability Standard.

Comments

67. In its comments, NERC clarifies that ''mutual consent'' is required by part 2.3 of Requirement R2 of Reliability Standard PRC–006–1 when planning coordinators select island boundaries that do not coincide with the Regional Entity area or Interconnection boundary. NERC explains that, when a planning coordinator selects an island boundary that does not coincide with the Regional Entity area or Interconnection boundary, mutual consent must be obtained from neighboring planning coordinators to ensure that the deviation does not result in a portion of the bulk electric system being excluded from a UFLS assessment.

68. EEI states that the Reliability Standard PRC–006–1 requires ''mutual consent'' between affected planning coordinators and that the level of consent is voluntary and undefined to allow the parties to determine the level of cooperation necessary. EEI maintains that this scheme is necessary to ensure that all parts of the bulk electric system are covered within a UFLS plan.

69. MISO states that planning coordinators should be able to study islands as they see fit and without the consent of neighboring planning coordinators, which includes studying islands that deviate from Regional Entity boundaries. MISO maintains that there is no detrimental effect associated with multiple or non-coordinated island studies.

70. NYISO comments that it regularly conducts stability evaluations on a New York Control Area and regional basis and is aware of the potential breakpoints on the system.

71. EPSA states that UFLS programs are best developed on an interconnection-wide basis, not on a regional basis. EPSA notes that region-specific Reliability Standards could undermine Reliability Standards PRC–006–1 and EOP–003–2 if they do not address interregional coordination among planning coordinators.

72. PSEG states that it has concerns with the active draft regional versions of PRC–006–1 pertaining to Reliability*First* Corporation and NPCC. PSEG maintains that these regional versions will hamper needed interregional coordination for UFLS program design in the Eastern Interconnection (i.e., the proposed regional standards do not require interregional coordination among planning coordinators and may require planning coordinators who span multiple regions to follow different standards); they violate a key NERC market principle by requiring existing generator owners to procure offsetting UFLS for the early tripping of their generating units if these units cannot meet specific performance requirements; and they may contravene the Energy Policy Act of 2005 [47] by placing NERC and the regions in the role of imposing generation adequacy requirements. PSEG maintains that UFLS is an interconnection-wide issue and should be addressed on an interconnection-wide basis.

Commission Determination

73. The Commission accepts NERC's clarification of the level of consent required between planning coordinators to adjust island boundaries under Reliability Standard PRC–006–1, Requirement R2.3. As stated in the NOPR, we believe that the reliability of the bulk electric system benefits from entities basing their studies on physical characteristics, as allowed in PRC–006–1, as opposed to hewing to artificial boundaries.[48] To the extent MISO suggests in its comments that planning coordinators should not have to reach a consensus with neighboring planning authorities when adjusting island boundaries, we disagree. As NERC and EEI explain in their comments, it is important to coordinate adjustments in island boundaries to ensure that no part of the bulk electric system is inadvertently left unstudied.[49] However, nothing in PRC–006–1 precludes entities from conducting additional assessments based on any island boundaries they wish to analyze.

74. With respect to the comments from EPSA and PSEG, there are no Regional Reliability Standards currently before us in this matter and, therefore, the matter is not ripe for us to address.

G. Automatic Load Shedding and Manual Load Shedding

75. In the NOPR, the Commission observed that there are no requirements in Reliability Standard PRC–006–1 to coordinate automatic load shedding by UFLS and manual load shedding under Reliability Standard EOP–003–2. The Commission noted that once load is disconnected from the system, either automatically or manually, it cannot be used again to arrest frequency decline. The Commission expressed concern that in the event that a load resource is double-counted and removed during automatic UFLS, the manual load shedding cannot be completed if called upon. Accordingly, the Commission stated that resources allocated to each type of load shedding (i.e., automatic and manual) should not overlap. The Commission sought comments on how the coordination of automatic and manual load shedding is considered in light of the fact that the Reliability Standards do not explicitly require coordination.

Comments

76. NERC acknowledges that the Reliability Standards do not explicitly require coordination of manual load shedding and UFLS but states that

[46] NERC Petition at 75–76.

[47] Energy Policy Act of 2005, Public Law 109–58, 119 Stat. 594 (2005).

[48] NOPR, FERC Stats & Regs. ¶ 32,682 at P 46.

[49] NERC Comments at 12; EEI Comments at 10.

Reliability Standard EOP–003–2 addresses the concern that a load resource could be unintentionally double-counted. Specifically, NERC maintains that Requirement R6 of EOP–003–2 requires transmission operators and balancing authorities to include load in the manual load shedding program that is not included in the UFLS program to achieve the reliability objective of EOP–003–2.[50]

77. Wisconsin Electric and FRCC state that it is difficult for a UFLS program not to overlap with manual loadshed plans. Wisconsin Electric comments that it is ''overly conservative to prevent a load from being used in both a UFLS program and a manual loadshed plan.'' [51] Wisconsin Electric also observes that a reliability coordinator may require an entity to manually shed load that is part of a UFLS program, which the entity cannot ignore. FRCC maintains that a non-overlap rule is likely to have a negative impact on reliability because it may reduce the amount of load available to address capacity emergencies. FRCC further contends that underfrequency events are rare and it is even less likely for an underfrequency event to coincide with a capacity emergency.

78. Dominion states that the Commission should not force coordination of manual load shedding and UFLS load shedding because it would prevent balancing authorities and transmission operators from using currently available tools to manage emergency conditions. Dominion contrasts the precision of manual load shedding with the widespread automatic response provided by UFLS programs. According to Dominion, forced coordination could remove manual load shedding from the emergency response toolkit for local issues, which, according to Dominion, could allow them to turn into cascading events. EEI states that the purpose of UFLS programs and manual load shedding are separate. EEI argues that, while a broad understanding of the operation of each program is important, coordination to the level implied by the NOPR serves no purpose since each program addresses different problems. EEI further notes that coordination in the form of ''information sharing'' already occurs. NYISO also states that manual load shedding and UFLS address different issues and should be addressed in separate Reliability Standards.

79. SWPA states that there is a need to address what consideration planning authorities give to other protective schemes and remedial action plans. SWPA maintains that Reliability Standard PRC–006–1 should address how a balancing authority and transmission operator address overlap concerns where most of its balancing authority area entities are subject to load shedding plans under Reliability Standard EOP–003–2 but these loads are also subject to UFLS plans under PRC–006–1.

Commission Determination

80. Based on the comments, we find that there is an adequate level of coordination between UFLS and manual load shedding. We are persuaded by NERC's comments that the term ''additional load'' in Reliability Standard EOP–003–2, Requirement R6, includes resources allocated to manual load shedding that are not included in the UFLS program. UFLS and manual load shedding programs are developed separately and have, as EEI stated, separate purposes. As such, to avoid insufficiencies in available load if manual load shedding is needed after UFLS has been activated, UFLS and manual load shedding programs cannot be planned to shed the same load.

H. Elimination of Requirements for Balancing Authorities in EOP–003–2

81. In the NOPR, the Commission observed that Requirements R2, R4, and R7 of the currently-effective Reliability Standard EOP–003–1 apply to transmission operators and balancing authorities but that Reliability Standard EOP–003–2 eliminates balancing authorities from Requirements R2, R4, and R7. The Commission sought clarification as to why these balancing authority responsibilities were not incorporated into Reliability Standards PRC–006–1 or EOP–003–2. The Commission also sought comments as to why balancing authorities should not be informed of UFLS program plans that directly impact balancing authority functions.

Comments

82. NERC states that Reliability Standard EOP–003–2 removes requirements on UFLS design, incorporates them in Reliability Standard PRC–006–1, and assigns those activities to planning coordinators. NERC further states that EOP–003–2 does not remove any requirements for UVLS, which are assigned to transmission operators. NERC maintains that, while balancing authorities contribute to managing Interconnection frequency by balancing load and generation resources in real-time, UFLS and UVLS programs are automatic and must be set in advance. NERC, however, agrees that balancing authorities should be informed of UFLS program plans that directly impact the balancing authority function.

83. EEI, TAPS, MISO, Dominion and NYISO largely support NERC's comments. EEI states that the changes in Reliability Standard EOP–003–2 are consistent with the roles and responsibilities of balancing authorities and transmission operators. EEI also maintains that balancing authorities are already informed of UFLS programs by transmission operators because balancing authorities and transmission operators ''are specifically identified as coordinating other load shedding plans as identified in EOP–003–2'' and to ''effectively develop those plans [balancing authorities] and [transmission operators] must have knowledge of the UFLS programs of which [transmission operators] are intimately aware through PRC–006–1.'' [52]

84. TAPS states that Reliability Standards PRC–006–1 and EOP–003–2 clarify the requirements in the existing Reliability Standards and assign them to the functional entities best suited to program design. TAPS also states that Reliability Standard PRC–001–1, Requirement R1 ensures that balancing authorities are familiar with UFLS programs because the requirement provides that they ''shall be familiar with the purpose and limitations of protection system schemes applied in its area.'' [53]

85. MISO states that balancing authorities need not be informed of UFLS programs because planning coordinators are the functional entities tasked with overseeing those programs. MISO also contends that requiring planning coordinators to report to balancing authorities on UFLS programs would impose additional costs with little benefit to reliability. MISO notes, however, that balancing authorities could benefit if NERC periodically published prevailing UFLS set points by planning coordinator area.

86. Dominion states that planning coordinators should not be required to inform balancing authorities of UFLS program plans because balancing authorities have no role in the design and implementation of UFLS and have no action to take to affect the successful operation of UFLS.

87. NYISO comments that balancing authorities have no role in load shedding and agrees with the removal of

[50] NERC Comments at 12.

[51] Wisconsin Electric Comments at 3.

[52] EEI Comments at 13.

[53] TAPS Comments at 8–9.

UFLS references from Reliability Standard EOP–003–2.

88. SWPA states that balancing authorities, by definition, do not perform the functions referred to in Reliability Standards PRC–006–1 or EOP–003–2, Requirements R2, R4, and R7. However, SWPA believes that PRC–006–1 should incorporate language that ensures that balancing authorities are kept informed of UFLS program plans that directly impact the balancing authority functions.

Commission Determination

89. The Commission accepts the elimination of requirements for balancing authorities in Reliability Standard EOP–003–2. NERC states in its comments that ''all activities required for UFLS programs in the existing standards are incorporated into PRC–006–1, and are assigned to the Planning Coordinator,'' [54] and that balancing authorities will still be made aware of UFLS programs in order to ''be familiar with the purpose and limitations of protection system schemes applied in its area,'' [55] as stated in Reliability Standard PRC–001–1, Requirement R1. To that end, the Commission believes that the comments address the questions raised in the NOPR regarding the elimination of balancing authority responsibility for Requirements R2, R4, and R7 of EOP–003–2.

I. Violation Risk Factors and Violation Severity Levels

90. In the NOPR, the Commission proposed to approve the VRFs and VSLs in Reliability Standards PRC–006–1 and EOP–003–2. However, the Commission sought comments on one VSL and one VRF for PRC–006–1.

91. The Commission stated that the ''Lower VSL'' assignment for Requirement R8 in PRC–006–1 applies when a UFLS entity fails to provide data to its planning coordinator for 5 to 10 calendar days following the schedule specified by the planning coordinator. The Commission noted in the NOPR that Requirement R8 of PRC–006–1 does not include a 5-day grace period for providing data to planning coordinators and thus the subject VSL assignment may be inconsistent with the Commission's VSL Guideline 3.

92. The Commission noted that NERC proposed a ''Medium'' VRF for Reliability Standard PRC–006–1, Requirement R5, which requires planning coordinators to coordinate their UFLS program design with other planning coordinators whose area is in part of the same identified island. The Commission observed the statement in NERC's petition that Requirement R5 is ''not related to similar reliability goals in other standards.'' [56] However, the Commission explained that coordination of load shedding plans is required in a similar manner in Requirement R3 of currently-effective Reliability Standard EOP–003–1, which includes a VRF of ''High.'' [57] The Commission stated that the lack of coordination of UFLS programs among planning coordinators within the same identified island could lead to ineffective UFLS operations and further cascading outages within the island when UFLS is activated. The Commission explained that this might be inconsistent with Guideline 3 of the Commission's VRF Guidelines states that ''[a]bsent justification to the contrary, the Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.'' [58]

Comments

93. NERC agrees with the NOPR regarding both the ''Lower VSL'' for Requirement R8 of Reliability Standard PRC–006–1 and the VRF for Requirement R5 of PRC–006–1. In its comments, NERC proposes to modify the ''Lower VSL'' to remove the phrase ''more than 5 calendar days but'' to address the concern stated in the NOPR. NERC also proposes to modify the VRF for Requirement R5 by raising it from ''Medium'' to ''High.''

94. EEI, SWPA, and NYISO agree with the need to modify the VSL for Requirement R8 of PRC–006–1, consistent with NERC's proposal. NYISO also supports changing the VRF for PRC–006–1, Requirement R5.

Commission Determination

95. Consistent with the proposal in NERC's comments, the Commission directs the ERO to modify the language of the Lower VSL for Reliability Standard PRC–006–1, Requirement R8 and the Medium VRF for PRC–006–1, Requirement R5. NERC is directed to submit the revised VRF and VSL within 30 days of the effective date of this final rule.

J. Implementation Plan and Effective Date

96. In the NOPR, the Commission noted that NERC requests an effective date for Reliability Standards PRC–006–1 and EOP–003–2 of one year following the first day of the first calendar quarter after applicable regulatory approvals with respect to all Requirements of the proposed Reliability Standards *except* Parts 4.1 through 4.6 of Requirement R4 of PRC–006–1. With respect to Parts 4.1 through 4.6 of Requirement R4 of PRC–006–1, NERC requests an effective date of one year following the receipt of generation data as required in Reliability Standard PRC–024–1,[59] but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC–006–1. The Commission sought comments about any potential reliability gaps that may occur during the development and implementation of PRC–024–1, such as how the planning coordinators will adequately determine and apply UFLS simulations and plans in the absence of generator trip settings.

Comments

97. NERC maintains that there should not be a reliability gap because planning coordinators have access to and utilize trip settings in UFLS assessments. NERC explains its proposal by noting that generator owners currently cannot be compelled to provide trip settings to planning coordinators. NERC states that the implementation schedule defers a compliance obligation for planning coordinators to model the trip settings until a compliance obligation for generator owners to provide these settings exists.

98. EEI believes that a reliability gap will exist until draft Reliability Standard PRC–024–1 is approved, but it believes that the gap is minor and manageable. EEI agrees with NERC that information that will be mandated in PRC–024–1 is already supplied through mutual cooperation between entities. EEI states that the Commission might consider directing NERC to reevaluate its priority list to determine if the PRC–024–1 project is being given sufficient priority.

99. TAPS comments that planning coordinators have the ability to run UFLS simulations, even though modeling generator trip settings is not currently mandatory, because all

[54] NERC Comments at 13.

[55] NERC Comments at 14.

[56] NERC Petition at 46.

[57] Reliability Standard EOP–003–2 includes the same VRF assignment of ''High'' for Requirement R3.

[58] *North American Electric Reliability Corp.,* 119 FERC ¶ 61,145, at P 25 (2007).

[59] Draft Reliability Standard PRC–024–1 addresses ''Generator Performance During Frequency and Voltage Excursions'' and is currently being developed in the NERC standard drafting process under Project 2007–09 (Generator Verification), which is one of NERC's priority projects.

significantly sized generators are included in models. TAPS contends that while some generators that trip outside of the UFLS set points may not be modeled, this will not have a significant impact on the reliability of the bulk electric system.

Commission Determination

100. The Commission approves the implementation plan and effective dates of Reliability Standards PRC–006–1 and EOP–003–2. We agree with EEI that there is a reliability gap given the lack of mandatory requirements for providing generator trip settings, which will continue until draft Reliability Standard PRC–024–1 is approved. The Commission, however, also agrees with EEI that the gap is limited because the information mandated by PRC–024–1 is already supplied through mutual cooperation between utilities. To ensure that any gap pending implementation of PRC–024–1 remains limited, the Commission encourages the current practice of voluntarily sharing generator trip settings between entities to continue.

III. Information Collection Statement

101. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[60] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

102. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of Paperwork Reduction Act of 1995.[61] The Commission solicited comments on the need for and the purpose of the information contained in Reliability Standard PRC–006–1 and EOP–003–2 and the corresponding burden to implement them. The Commission received comments on specific requirements in the Reliability Standards, which we address in this final rule. However, we did not receive any comments on our reporting burden estimates.

103. This final rule approves Reliability Standards PRC–006–1 and EOP–003–2, which would replace currently effective Reliability Standards PRC–007–0, PRC–009–0, EOP–003–1 and NERC-approved Reliability Standard PRC–006–0.[62] As noted previously, Reliability Standard PRC–006–0 was never approved by the Commission, and therefore has never been mandatory and enforceable. On the other hand, Reliability Standards PRC–007–0 and PRC–009–0 were approved by the Commission and are currently mandatory and enforceable. Because Proposed Reliability Standard PRC–006–1 incorporates the requirements from Reliability Standards PRC–006–0, PRC–007–0, and PRC–009–0 some of the existing requirements will become mandatory and enforceable (where previously they were voluntary), while others continue to be so. To properly account for the burden on respondents, the Commission will treat the burden resulting from NERC-approved Reliability Standard PRC–006–0 as essentially new to the industry, even though it is likely that most applicable entities have already been complying.[63]

104. The reporting requirements in Reliability Standard EOP–003–2 are virtually the same as those in currently effective Reliability Standard EOP–003–1. The difference is that Reliability Standard EOP–003–2 eliminates balancing authorities from Requirements R2 and from Measure M1.[64] This requirement and measure deal with establishing and documenting automatic load shedding plans.

105. *Public Reporting Burden:* Our estimate below regarding the number of respondents is based on the NERC compliance registry as of July 29, 2011. According to the NERC compliance registry, there are 72 planning coordinators and 126 balancing authorities. The individual burden estimates are based on the time needed to gather data, run studies, and analyze study results to design or update the UFLS programs. Additionally, documentation and the review of UFLS program results by supervisors and management is included in the administrative estimations. These are consistent with estimates for similar tasks in other Commission approved standards.

PRC–006–1 (automatic underfrequency load shedding)[65]	Number of respondents annually	Number of responses per respondent	Average burden hours per response		Total annual burden hours
	(1)	(2)	(3)		(1) × (2) × (3)
PCs*: Design and document Automatic UFLS Program	72	1	120		8,640
PCs: Management Review of Documentation	72	1	40		2,880
PCs: Record Retention	72	1	16		1,152
Total					12,672
EOP–003–2 (Load Shedding Plans)[66]					
Removal of BAs* from Reporting Requirements in R2 and M1 (Burden Reduction).	126	1	Reporting	¥10	¥1,260
	126	1	Record Retention	¥1	¥126
Total					¥1,386
Net Change in Burden *(Total Annual Hours for Collection)*					11,286

[60] 5 CFR 1320.11.

[61] 44 U.S.C. 3507(d)

[62] PRC–006–0 was not approved by the Commission but remained effective as a NERC-approved standard (but not mandatory or enforceable). The other three standards were approved by the Commission. *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[63] This statement is made because currently effective Reliability Standards PRC–007–0 and PRC–009–0 required UFLS entities to follow the UFLS program implemented by Reliability Standard PRC–006–0. Therefore, it is likely that entities have already been following the requirements contained in Reliability Standard PRC–006–0. However, the burden associated with the UFLS entities is not new because it was accounted for under Commission approved Reliability Standards PRC–007–0 and PRC–009–0.

[64] Balancing authorities are also removed from Requirements R4 and R7, but these do not have reporting requirements associated with them.

[65] Reliability Standard PRC–006–1 applies to both planning coordinators and to UFLS entities.

[66] Transmission operators also have to comply with Reliability Standard EOP–003–2. Since the applicable reporting requirements (and associated burden) have not changed from the existing standard, these entities are not included here.

*PC = Planning Coordinator; BA = Balancing Authority.

Total Net Annual Cost (Reporting + Record Retention) [67]: = $1,414,656 ¥ $154,728 = $1,259,928.

D *Total Reporting Cost for Planning Coordinators:* = 11,520 hours @ $120/hour = $1,382,400.

D *Total Record Retention Cost for Planning Coordinators:* 1,152 hours @ $28/hour = $32,256.

D Total Reporting and Record Retention Cost Savings for Balancing Authorities: = (1,260 hours @ $120/hour) + (126 hours @ $28/hour) = $154,728.

Title: Mandatory Reliability Standards for the Bulk-Power System

Action: Proposed Collection FERC–725A.

OMB Control No.: 1902–0244.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: This Final Rule approves the requested modifications to Reliability Standards pertaining to automatic underfrequency load shedding. The Reliability Standards help ensure the reliable operation of the bulk electric system by arresting declining frequency and assisting recovery of frequency following system events leading to frequency degradation.

Internal Review: The Commission has reviewed the Reliability Standards and made a determination that its action is necessary to implement section 215 of the FPA. These requirements, if accepted, should conform to the Commission's expectation for UFLS programs as well as procedures within the energy industry.

106. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *DataClearance@ferc.gov*, phone: (202) 502–8663, fax: (202) 273–0873].

107. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–4638, fax: (202) 395–7285]. For security reasons, comments to OMB should be submitted by email to: *oira_submission@omb.eop.gov*. Comments submitted to OMB should include Docket Number RM11–20 and OMB Control Number 1902–0244.

[67] The hourly reporting cost is based on the cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

IV. Environmental Analysis

108. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[68] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[69] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

109. The Regulatory Flexibility Act of 1980 (RFA) [70] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[71] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[72]

110. Reliability Standard PRC–006–1 establishes design, assessment, and documentation requirements for automatic UFLS programs. It will be applicable to planning coordinators and entities that are responsible for the ownership, operation, or control of UFLS equipment. Reliability Standard EOP–003–2 removes balancing authorities from having to comply with Requirement R2 and Measure M1 of the standard. Comparison of the NERC compliance registry with data submitted to the Energy Information Administration on Form EIA–861 indicates that perhaps as many as 8 small entities are registered as planning coordinators and 18 small entities are registered as balancing authorities. The Commission estimates that the small planning coordinators to whom the Reliability Standard will apply will incur compliance and recordkeeping costs of $157,184 ($19,648 per planning coordinator) associated with the Standard's requirements. The small balancing authorities will receive a savings of $154,728 ($8,596 per balancing authority). Accordingly, Reliability Standards PRC–006–1 and EOP–003–2 should not impose a significant operating cost increase or decrease on the affected small entities.

111. Based on this understanding, the Commission certifies that these Reliability Standards will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VI. Document Availability

112. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington DC 20426.

113. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

[68] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[69] 18 CFR 380.4(a)(2)(ii).

[70] 5 U.S.C. 601–612.

[71] 13 CFR 121.101.

[72] 13 CFR 121.201, Sector 22, Utilities & n.1.

114. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov*.

VII. Effective Date and Congressional Notification

115. These regulations are effective July 10, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 40

Electric power; Electric utilities; Reporting and record keeping requirements.

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Appendix

Commenters

Abbreviation	Commenter
Dominion	Dominion Resources Services, Inc.
EEI	Edison Electric Institute.
EPSA	Electric Power Supply Association.
FRCC	Florida Reliability Coordinating Council, Inc.
G&T Cooperatives	Associated Electric Cooperative, Inc.; Basin Electric Power Cooperative; and Tri-State Generation and Transmission Association, Inc.
KCP&L	Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company.
MISO	Midwest Independent Transmission System Operator, Inc.
NERC	North American Electric Reliability Corporation.
NYISO	New York Independent System Operator, Inc.
PSEG	Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC.
SWPA	Southwestern Power Administration.
TAPS	Transmission Access Policy Study Group.
Wisconsin Electric	Wisconsin Electric Power Company.

[FR Doc. 2012–11316 Filed 5–10–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 179

[Docket No. FDA–1999–F–0021; formerly 1999F–2673]

Irradiation in the Production, Processing and Handling of Food

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule; denial of requests for a hearing and response to objections.

SUMMARY: The Food and Drug Administration (FDA) is denying requests for a hearing on the final rule that amended the food additive regulations to provide for the safe use of ionizing radiation for the control of microbial pathogens in seeds for sprouting. After reviewing objections to the final rule and requests for a hearing, FDA has concluded that the objections do not justify a hearing or otherwise provide a basis for revoking the regulation.

FOR FURTHER INFORMATION CONTACT: Teresa A. Croce, Center for Food Safety and Applied Nutrition (HFS–265), Food and Drug Administration, 5100 Paint Branch Pkwy., College Park, MD 20740, 240–402–1281.

SUPPLEMENTARY INFORMATION:

I. Introduction

In the **Federal Register** of August 16, 1999 (64 FR 44530), FDA published a notice announcing the filing of a food additive petition (FAP 9M4673) submitted by Caudill Seed Co., Inc., to amend the regulations in part 179 *Irradiation in the Production, Processing, and Handling of Food* (21 CFR part 179) by providing for the safe use of ionizing radiation to control microbial pathogens in seeds for sprouting. In response to this petition, FDA issued a final rule in the **Federal Register** of October 30, 2000 (65 FR 64605), permitting the irradiation of seeds for sprouting to control microbial pathogens in alfalfa and other sprouting seeds at an absorbed dose not to exceed 8.0 kiloGray (kGy) (hereafter referred to as the ''seeds for sprouting rule''). FDA based its decision on data in the petition and in its files. The preamble to the final rule advised that objections to the final rule and requests for a hearing were due within 30 days of the publication date (i.e., by November 29, 2000).

II. Objections and Requests for a Hearing

Section 409(f)(1) of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 348(f)(1)) provides that, within 30 days after publication of an order relating to a food additive regulation, any person adversely affected by such order may file objections, ''specifying with particularity the provisions of the order deemed objectionable, stating reasonable grounds therefor [sic], and requesting a public hearing upon such objections.''

Under the food additive regulations at 21 CFR 171.110, objections and requests for a hearing are governed by part 12 (21 CFR part 12) of FDA's regulations. Under § 12.22(a), each objection must meet the following conditions: (1) Must be submitted on or before the 30th day after the date of publication of the final rule; (2) must be separately numbered; (3) must specify with particularity the provision of the regulation or proposed order objected to; (4) must specifically state each objection on which a hearing is requested; failure to request a hearing on an objection constitutes a waiver of the right to a hearing on that objection; and (5) must include a detailed description and analysis of the factual information to be presented in support of the objection if a hearing is requested; failure to include a description and analysis for an objection constitutes a waiver of the right to a hearing on that objection.

Following publication of the final rule permitting the irradiation of seeds for sprouting to control food-borne pathogens, FDA received numerous submissions within the 30-day objection

From: Guy V. Zito
To: grpStaff
Subject: Summary of Order 763 approving NERC UFLS Continent wide standard
Date: Friday, May 11, 2012 7:45:16 AM
Attachments: Highlights UFLS FERC Order 763.docx

To All,

It seems NERC has softened its position on many of the issues it identified in the Notice of Proposed Rulemaking "NOPR". Attached are highlights from the Order. NERC backed away from all the issues previously expressed and only issued one Directive which will require a compliance filing by NERC within 30 days to indicate how they plan to comply with the directive. This could be impactive to our recently filed Regional Standard where some commenters believe that UFLS should be interconnection wide and no regional standards arranged non-interconnection wide should be adopted. The Commission did not respond to that comment and noted they wait for a regional standard to be before them and the issue to be "ripe". Sounds like NPCC's UFLS, filed last Friday, will set the stage for this debate.

Guy

139 FERC ¶ 61,246
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-11-000; Order No. 764]

Integration of Variable Energy Resources

(Issued June 22, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission is amending the *pro forma* Open Access Transmission Tariff to remove unduly discriminatory practices and to ensure just and reasonable rates for Commission-jurisdictional services. Specifically, this Final Rule removes barriers to the integration of variable energy resources by requiring each public utility transmission provider to: (1) offer intra-hourly transmission scheduling; and, (2) incorporate provisions into the *pro forma* Large Generator Interconnection Agreement requiring interconnection customers whose generating facilities are variable energy resources to provide meteorological and forced outage data to the public utility transmission provider for the purpose of power production forecasting.

EFFECTIVE DATE: This rule will become effective **[insert date 60 days after publication in the FEDERAL REGISTER]**.

FOR FURTHER INFORMATION CONTACT:

Jessica L. Cockrell (Technical Information)
Office of Energy Policy and Innovation
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8190

Andrea Hilliard (Legal Information)
Office of General Counsel – Energy Markets
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8288

SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,246
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

Integration of Variable Energy Resources — Docket No. RM10-11-000

ORDER NO. 764

FINAL RULE

(Issued June 22, 2012)

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I. Introduction

1. In this Final Rule, the Commission acts under section 206 of the Federal Power Act (FPA) to adopt reforms that will remove barriers to the integration of variable energy resources (VER)[1] and ensure that the rates, terms, and conditions for Commission-jurisdictional services provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential.[2] As the Commission noted in the Proposed Rule, VERs are making up an increasing percentage of new generating capacity being brought on-line.[3] This evolution in the Nation's generation fleet has caused the industry to reevaluate practices developed at a time when virtually all generation on the system could be scheduled with relative precision and when only load exhibited significant degrees of within-hour variation. As part of this evaluation, the Commission initiated this rulemaking proceeding to consider its own rules and, based on the comments received, concludes that reforms are needed in order to ensure that transmission customers are not exposed to excessive or unduly discriminatory charges

[1] As defined in the Notice of Proposed Rulemaking, a Variable Energy Resource is a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities. *See Integration of Variable Energy Resources Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,664, at P 64 (2010) (Proposed Rule).

[2] 16 U.S.C. 824e (2006).

[3] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 13.

and that public utility transmission providers have the information needed to efficiently manage reserve-related costs.

2. Specifically, the Commission amends the *pro forma* Open Access Transmission Tariff (OATT) to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals. There is currently no requirement to provide transmission customers the opportunity to adjust their transmission schedules within the hour to reflect changes in generation output. As a result, transmission customers have no ability under the *pro forma* OATT to mitigate Schedule 9 generator imbalance charges in situations when the transmission customer knows or believes that generation output will change within the hour. This lack of ability to update transmission schedules within the hour can cause charges for Schedule 9 generator imbalance service to be unjust and unreasonable or unduly discriminatory. Accordingly, the Commission amends the *pro forma* OATT to correct this deficiency.

3. The Commission also amends the *pro forma* Large Generator Interconnection Agreement (LGIA) to require new interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider with which the customer is interconnected, where necessary for that public utility transmission provider to develop and deploy power production forecasting. Power production forecasts can provide public utility transmission providers with advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than through the

deployment of reserve service, such as regulation reserves which can be more costly. This Final Rule facilitates a public utility transmission provider's use of power production forecasting by amending the *pro forma* LGIA to require new interconnection customers whose generating facilities are VERs to provide the underlying data necessary for public utility transmission providers to perform such forecasts accurately.

4. The Commission declines, however, to modify the *pro forma* OATT to include a new Schedule 10 governing generator regulation service as set forth in the Proposed Rule. The Commission intended for the proposed Schedule 10 to provide clarity to public utility transmission providers and transmission customers alike by setting forth a generic approach to the provision of generator regulation service. In response, numerous commenters urged the Commission not to adopt a standardized approach to generator regulation service, stressing that flexibility is needed in the design of capacity services needed to efficiently integrate VERs into the transmission system. The Commission agrees and, accordingly, will continue a case-by-case approach to evaluating proposed generator regulation service charges. To assist public utility transmission providers and their customers in the development and evaluation of such proposals, the Commission instead provides guidance in response to the comments submitted.

5. Taken together, the reforms adopted and guidance provided in this Final Rule are intended to address issues confronting public utility transmission providers and VERs and to allow for the more efficient utilization of transmission and generation resources to the benefit of all customers. This, in turn, fulfills our statutory obligation to ensure that

Commission-jurisdictional services are provided at rates, terms, and conditions of service that are just and reasonable and not unduly discriminatory or preferential.

Background

6. In 1996, the Commission issued Order No. 888, which found that it was in the economic interest of public utility transmission providers to deny transmission service or to offer transmission service on a basis that is inferior to what they provide to themselves.[4] Concluding that unduly discriminatory and anticompetitive practices existed in the electric industry and that, absent Commission action, such practices would increase as competitive pressures in the industry grew, the Commission in Order No. 888 required all public utility transmission providers that own, control, or operate transmission facilities used in interstate commerce to have on file an open access, non-discriminatory transmission tariff that contains minimum terms and conditions of non-discriminatory service. As relevant here, the *pro forma* OATT contains terms for scheduling transmission service and the provision of ancillary services.

7. The Commission later turned its attention to the process by which large generators interconnect with the interstate transmission system. In Order No. 2003, the Commission

[4] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,682 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

concluded that there was a pressing need for a single set of procedures and a single, uniformly applicable interconnection agreement for large generator interconnections.[5] Accordingly, the Commission adopted standard procedures (the Large Generator Interconnection Procedures or LGIP) and a standard agreement (the LGIA) for the interconnection of generation resources greater than 20 MW.[6] These reforms were designed to minimize opportunities for undue discrimination and to expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.[7]

8. In Order No. 2003-A, the Commission explained that the interconnection requirements adopted in Order No. 2003 were based on the needs of traditional synchronous generators and that a different approach may be appropriate for generators relying on newer technology.[8] Therefore, Commission exempted wind resources from certain sections of the LGIA and added Appendix G to the LGIA, as a placeholder for the

[5] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 11 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[6] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146.

[7] *Id.*

[8] Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 407 & n.85.

inclusion of interconnection standards specific to newer technologies.[9] Subsequently, in Orders Nos. 661 and 661-A, the Commission adopted a package of interconnection standards applicable to large wind generators for inclusion in Appendix G of the LGIA.[10]

9. In recognition of the evolving energy industry and in a further effort to remedy the potential for undue discrimination, the Commission returned to the *pro forma* OATT in Order No. 890 and implemented a series of changes to the requirements of open access transmission service.[11] Among other things, the Commission adopted a set of transmission planning principles,[12] created a new *pro forma* ancillary service schedule designed to address generator imbalances,[13] and instituted a new conditional firm

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[9] *Id.*

[10] *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[11] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[12] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at PP 444-561. In June 2011, the Commission further amended the *pro forma* OATT to require, among other things, that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and has a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 176 FR 49842 (Aug. 11 2011), FERC Stats. & Regs. ¶ 31,323 (2011).

[13] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at PP 663-72.

transmission product.[14] With regard to imbalance charges, the Commission found that such charges should be designed to provide appropriate incentives to keep schedules accurate without being excessive and otherwise result in consistency in charges between and among energy and generator imbalances.[15] The Commission recognized that intermittent resources, such as VERs, cannot always accurately follow their schedules and that high penalties for imbalances will not lessen the incentive to deviate from their schedules. Accordingly, the Commission exempted intermittent resources from third-tier deviation band of imbalance penalties.[16]

10. Against this backdrop, the Commission in January 2010 issued a Notice of Inquiry in this proceeding to explore the extent to which barriers may exist that impede the reliable and efficient integration of VERs into the electric grid and whether reforms are needed to eliminate those barriers.[17] The Commission noted that the amount of VERs is rapidly increasing, reaching a point where such resources are becoming a significant component of the nation's energy supply portfolio.[18] In order to determine whether any rules, regulations, tariffs or industry practices within the Commission's jurisdiction

[14] *Id.* PP 911-15.

[15] *Id.* P 72.

[16] *Id.* P 665.

[17] *Integration of Variable Energy Resources Notice of Inquiry*, FERC Stats. & Regs. ¶ 35,563 (2010) (Notice of Inquiry).

[18] *Id.* P 2.

hinder the reliable and efficient integration of VERs, the Commission sought comment on a range of subject areas: (1) power production forecasting, including specific forecasting tools and data and reporting requirements; (2) scheduling practices, flexibility, and incentives for accurate scheduling of VERs; (3) forward market structure and reliability commitment processes; (4) balancing authority area coordination and/or consolidation; (5) suitability of reserve products and reforms necessary to encourage the efficient use of reserve products; (6) capacity market reforms; and (7) redispatch and curtailment practices necessary to accommodate VERs in real time.[19] The response from commenters was significant, with more than 135 entities submitting comments, many of which urged the Commission to undertake basic reforms in response to the increasing number of VERs being integrated into the system.

II. The Need for Reform

A. Commission Proposal

11. In light of the changes occurring within the electric industry, and based on comments submitted in response to the January 2010 Notice of Inquiry, the Commission issued the Proposed Rule to remedy operational and other challenges associated with VER integration that may be causing undue discrimination and increased costs ultimately borne by consumers. The Commission preliminarily found that the proposed set of reforms would eliminate operational procedures that have the *de facto* effect of imposing

[19] *Id.* P 12.

an undue burden on VERs. The Commission stated that the proposed reforms acknowledge that existing practices as well as the ancillary services used to manage system variability were developed at a time when virtually all generation on the system could be scheduled with relative precision and when only load exhibited significant degrees of within-hour variation. In proposing its reforms, the Commission sought to ensure that VERs are integrated into the transmission system in a coherent and cost-effective manner, consistent with open access principles.[20]

B. Comments

12. Commenters largely support initiation of a rulemaking proceeding to consider potential reforms to reduce discrimination and improve the efficiency of the transmission system.[21] Invenergy Wind, for example, states that the Proposed Rule reflects an important step forward in providing the regulatory foundation that will create an incentive for improvements in system operations and procurement practices necessary to

[20] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 17.

[21] *E.g.*, ACSF; AEP; AWEA; Argonne National Lab; BP Companies; Business Council; California ISO; CMUA; CEERT; Center for Rural Affairs; Clean Line; CGC; Defenders of Wildlife; Dominion; EEI; Environmental Defense Fund; Exelon; First Wind; Iberdrola; Idaho Power; ITC Companies; ISO New England; Independent Power Producers Coalition – West; ISO/RTO Council; Invenergy Wind; Large Public Power Council; Massachusetts DPU; MidAmerican; Midwest ISO Transmission Owners; M-S-R Public Power Agency; National Grid; NaturEner; Oregon & New Mexico PUC; NextEra; NorthWestern; PNW Parties; PJM; Powerex; Public Interest Organizations; RenewElec; SMUD; San Diego Gas & Electric; SEIA; Southern California Edison; SWEA; Southwestern; Sunflower and Mid-Kansas; Tacoma Power; Vestas; Western Farmers; Western Grid; Xcel.

support the addition of renewable resources to the nation's historical generation mix. BP Companies comment that it is important for the Commission to provide a level playing field for wind and solar-generated power.

13. Many commenters point to the importance of the Proposed Rule in removing market barriers to VER integration. NextEra comments that the instant proceeding is important because VERs have been developed in relatively modest amounts until recent years, and the existing market rules were designed to reflect the characteristics of more traditional generating resources (e.g., coal, natural gas and nuclear generation) rather than VERs. NextEra contends that existing rules were aimed at addressing the preferences and requirements of the resources and systems in the past, rather than to anticipate future changes. CEERT states that the Commission's initiative to remove market and operational barriers to VERs integration and eliminate undue discrimination against VERs is critical to making wholesale power markets more competitive and ensuring a sustainable energy future.

14. Iberdrola contends that this proceeding is the best opportunity available for the federal government to encourage the responsible development of renewable energy resources, and to avoid inadvertently stifling the growth of renewable energy resources in an effort to protect the economic interests of incumbents. Similarly, NaturEner comments that the reforms are long overdue and should be implemented without further delay and in a manner requiring prompt compliance. This proceeding, NaturEner states, represents substantial progress towards the elimination of antiquated rules, requirements and processes, a significant reduction in duplication, unnecessary expenditures and

inefficient allocation of resources, as well as an important step towards making the grid more robust, economical, and equitable.

15. Oregon & New Mexico PUC state that the Commission can play a valuable role in enabling the western electricity industry to reach state renewable energy goals at a reasonable cost to consumers by exercising its jurisdiction in these areas. Oregon & New Mexico PUC submit that the proposals in the Proposed Rule are an important step toward building the necessary foundation to integrate significant amounts of wind and solar in the West. Defenders of Wildlife similarly contend that by establishing a new rule which encourages VER integration, and long-term and much needed infrastructure investments can be made today to help spur the nation's growing renewable energy economy. ACSF states its strong support for Commission action to integrate VERs into a smarter, cleaner, and more flexible energy grid, whose principal design features should enable much more widespread investment and deployment of integrated and hybrid VER generation systems. ACSF states it is critical that the Commission exercise its authority to develop policies that send adequate economic signals that permit the country's most flexible, clean generation sources to provide complementary power for VERs.

C. Commission Determination

16. As noted above, the Commission initiated this proceeding through the issuance of a Notice of Inquiry to obtain information on barriers to the integration of VERs. The Commission sought to understand the challenges associated with the large-scale integration of VERs on the interstate transmission system and the extent to which existing operational practices may be imposing barriers to their integration. The

Commission explained that the changing characteristics of the nation's generation portfolio compelled a fresh look at existing policies and practices, leading the Commission to seek comment on a range of issues.

17. Based on its review of comments to the Notice of Inquiry, the Commission focused in the Proposed Rule on a series of basic reforms regarding transmission scheduling, data reporting requirements, and charges for generator regulation service that can and should be implemented in the near term.[22] The Commission explained that, taken together, the Proposed Reforms were designed to address issues confronting public utility transmission providers and VERs and to allow for the more efficient utilization of transmission and generation resources to the benefit of all customers.[23] The Commission acknowledged that the proposed reforms focused on discrete operational protocols that were only a subset of the issues for which comment was sought in the Notice of Inquiry.[24] The Commission stated its belief that focusing on the particular set of reforms proposed would provide a reasonable foundation for public utility transmission providers seeking to manage system variability associated with increased numbers of VERs and

[22] Proposed Rule, FERC Stats. & Regs ¶ 32,664 at P 18.

[23] *Id.* P 19.

[24] *Id.* PP 23-24.

that further study is required for many of the remaining issues raised in the Notice of Inquiry.[25]

18. The Commission received more than 1900 pages of initial and reply comments in response to the Proposed Rule. While differing in opinion on the merits of particular aspects of the Commission's proposal, commenters generally support the Commission's efforts to evaluate its rules through this rulemaking to explore further opportunities to reduce undue discrimination and reduce costs ultimately borne by consumers through more efficient use of the transmission system. Based on these comments, the Commission concludes that it is appropriate to act at this time to revise the transmission scheduling requirements of the *pro forma* OATT and incorporate data reporting requirements into the *pro forma* LGIA, as discussed in further detail later in this Final Rule.[26] As discussed throughout this Final Rule, these reforms are necessary to ensure that transmission customers are not exposed to excessive or unduly discriminatory charges for Schedule 9 generator imbalance service and to provide public utility transmission providers with information necessary to more efficiently manage reserve-related costs recovered from transmission customers through other ancillary services charges.

[25] *Id.* PP 12, 24.

[26] For the reasons discussed in Schedule 10 below, the Commission declines to standardize charges for generator regulation service through the adoption of a generic Schedule 10 to the *pro forma* OATT as suggested in the Proposed Rule.

19. The Commission takes this action now recognizing that the composition of the electric generation portfolio continues to change. VERs are making up an increasing percentage of new generating capacity being brought on-line. New wind generating capacity accounted for 35 percent of all newly installed generating capacity from 2007-2010.[27] As of December 2011, nearly 12,000 MW of additional wind generating capacity has been brought online and another 8,320 MW of wind generating capacity is currently under construction.[28] Current projections indicate that this expansion will continue, with the Energy Information Agency forecasting that generation from wind power will nearly double between 2009 and 2035.[29] This recent and future growth is being facilitated by

[27] *See* American Wind Energy Association, *Wind Power Outlook 2011* (Apr. 2011), *available at* http://www.awea.org/_cs_upload/learnabout/publications/reports/8546_1.pdf.

[28] American Wind Energy Association, *U.S. Wind Industry Fourth Quarter 2011 Market Report* (Jan. 2012), *available at* http://www.awea.org/learnabout/industry_stats/upload/4Q-2011-AWEA-Public-Market-Report_1-31.pdf. In addition, the amount of new photovoltaic generating capacity in 2011 increased by 108 percent over 2010 amounts, adding 1,855 MW of PV and bringing the total solar generating capacity to more than 4,470 MW. Utility installations increased by 185 percent in 2011, far more than residential or commercial market segments. *See* Solar Energy Industries Ass'n, *US Solar Market Insight Report 2011 Year-in-Review Executive Summary* (Mar. 2012), *available at* http://www.seia.org/galleries/pdf/SMI-YIR-2011-ES.pdf.

[29] Annual Energy Outlook at 75, *available at* http://www.eia.gov/forecasts/archive/aeo11/pdf/0383(2011).pdf.

developments in state and federal public policies that encourage the expansion of VER generation.[30]

20. As NERC has noted, higher levels of variable generation can alter the operation and characteristics of the bulk power system.[31] Increasing the relative amount of variable generation on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices and procedures, including the commitment of adequate reserves.[32] However, many of these operational protocols were developed for generation resources with a different set of characteristics. For example, the hourly scheduling protocols of the *pro forma* OATT reflect historical practices associated with operation of conventional generating resources that are relatively predictable and

[30] For example, as of May 2011, 30 states and the District of Columbia have a renewable portfolio standard or goal. FERC, Div. of Energy Market Oversight, *Renewable Power and Energy Efficiency Market: Renewable Portfolio Standards* 1 (updated May 2011), *available at* http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf). In addition, the federal production tax credit, which has been in effect intermittently since the early 1990s, provides an inflation-adjusted credit for power produced from VERs and other renewable resources. 26 U.S.C. 45 (2007). In February 2009, the American Recovery and Reinvestment Act not only extended the production tax credit for a period of three additional years but also instituted an investment tax credit, which allows developers of certain renewable generation facilities to take a 30 percent cash grant in lieu of the production tax credit. American Recovery and Reinvestment Tax Act of 2009, Pub. L. No. 111-5, § 1101, 123 Stat. 115, 319-20 (2009). Other federal policies that provide incentives to renewable generation facilities include accelerated depreciation of certain renewable generation facilities and loan guarantee programs.

[31] NERC, *Accommodating High Levels of Variable Generation* at 8, *available at* http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf.

[32] *Id.* at 59.

controllable when compared to VERs. Similarly, the interconnection requirements of Order No. 2003 were based on the needs of traditional synchronous generators, leading the Commission to revisit those requirements as applied to large wind generators in Order Nos. 661 and 661-A.

21. In Order No. 1000, the Commission recognized that changes in the generation mix influence the need for new transmission facilities and, as a result, Commission policies governing transmission planning and cost allocation.[33] The Commission concluded there that the increased focus on investment in new transmission projects made it critical to implement planning and cost allocation reforms to ensure that the transmission projects that come to fruition efficiently and cost-effectively meet regional needs. The Commission reaches a similar conclusion here. Changes in the generation mix and underlying public policies influencing investment in VER generation have accentuated the need to reform existing practices that unduly discriminate against VERs or otherwise impair the ability of public utility transmission providers and their customers to manage costs associated with VER integration effectively.

22. Specifically, we find that the adoption of intra-hour scheduling and data reporting to support power production forecasting will remedy undue discrimination and ensure just and reasonable rates through more efficient utilization of transmission and generation

[33] Order No. 1000, 76 FR 49842, FERC Stats. & Regs. ¶ 31,323 at PP 45-46.

resources.[34] With regard to transmission scheduling practices, existing hourly scheduling protocols can expose transmission customers to excessive or unduly discriminatory generator imbalance charges. Generator imbalance charges are assessed to pay for the energy service the transmission provider must offer to account for deviations between a transmission customer's scheduled delivery of energy from a generator and the amount of energy actually generated, and also to provide an appropriate incentive for transmission customers to maintain accurate schedules. Under Schedule 9 of the *pro forma* OATT, there is no requirement to provide customers the opportunity to adjust their transmission schedules within the hour to reflect changes in generator output. As a result, transmission customers have no ability under the *pro forma* OATT to mitigate Schedule 9 generator imbalance charges in situations where the customer knows or believes that generation output will change within the hour. Implementation of intra-hour scheduling under this Final Rule will provide VERs and other transmission customers the flexibility to adjust their transmission schedules, thus limiting their exposure to imbalance charges. Over time, implementation of intra-hour scheduling also will allow public utility transmission providers to rely more on planned scheduling and dispatch procedures, and less on reserves, to maintain overall system balance.

[34] In the Proposed Rule, the Commission also proposed to modify the *pro forma* OATT to include a new Schedule 10 governing generator regulation service. For the reasons discussed elsewhere in this Final Rule, the Commission declines to adopt that aspect of the Proposed Rule, instead providing guidance in response to comments submitted to assist public utility transmission providers and their customers in the development and evaluation of proposals on a case-by-case basis.

23. With regard to data reporting to support power production forecasting, the lack of data reporting requirements can limit the ability of public utility transmission providers to develop and deploy power production forecasts in an effort to more efficiently manage operating costs associated with the integration of VERs interconnecting to their systems. Under the existing requirements of the *pro forma* LGIA, public utility transmission providers are permitted to request this information, but there is no obligation for interconnection customers whose generating facilities are VERs to provide it. Implementation of reporting requirements commensurate with the power production forecasting employed by the public utility transmission provider will allow for more accurate commitment or de-commitment of resources providing reserves, ensuring that reserve-related charges imposed on customers remain just and reasonable and not unduly discriminatory or preferential. While the Commission declines to adopt a *pro forma* generator regulation and frequency response service, we note that public utility transmission providers that decide to file with the Commission to impose such a charge should, as part of any filing, consider the affect of the reforms we adopt in this Final Rule when developing proposed reserve capacity costs and evaluating whether to require different transmission customers to purchase or otherwise account for different quantities of generator regulation reserves.

24. Although focused on discrete issues, the implementation of intra-hour scheduling and reporting requirements through this Final Rule will allow for the efficient utilization of transmission and generation resources as an increasing amount of VER generation is integrated into the system. This in turn will ensure that the rates, terms, and conditions

for Commission-jurisdictional services provided by public utility transmission providers are just and reasonable and not unduly discriminatory. Our actions here are intended to build on, rather than undermine, existing efforts at the regional level to address VER integration. The Commission acknowledges that significant work has been done through industry initiatives seeking to craft regional solutions to the challenges associated with VER integration. For example, many public utility transmission providers in the Western Interconnection have implemented some form of transmission scheduling at 30-minute intervals.[35] The Commission is acting here to implement a minimum set of requirements for all public utility transmission providers and new interconnection customers whose generating facilities are VERs as necessary to facilitate the efficient integration of VERs. The Commission appreciates that these requirements go beyond some existing activities. The Commission nonetheless concludes that the reforms adopted herein are necessary to ensure that Commission-jurisdictional services are being provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

[35] *See, e.g., Ariz. Pub. Service Co.*, 137 FERC ¶ 61,023 (2011); *NorthWestern Corp.*, 136 FERC ¶ 61,119 (2011). We note that the Joint Initiative indicated in its comments at page 6 that its first step in offering 30-minute scheduling "is intended to address unanticipated events, not to move to half-hour scheduling." In addition, based on business practices posted on OASIS, some transmission providers reserve the right to suspend 30-minute scheduling.

III. Legal Authority to Implement Proposed Reforms

A. Commission Proposal

25. In the Proposed Rule, the Commission preliminarily found that the practice of hourly scheduling, the lack of VER power production forecasting, and the lack of a clear mechanism to recover the cost of providing generator regulation service may be contributing to undue discrimination and unjust and unreasonable rates in light of the entry and increasing presence of VERs on the transmission grid. Thus, the Commission proposed the following three reforms that require public utility transmission providers to: (1) amend the *pro forma* OATT to require intra-hourly transmission scheduling; (2) amend the *pro forma* LGIA to incorporate provisions requiring interconnection customers whose generating facilities are VERs to provide meteorological and operational data to public utility transmission providers for the purpose of improved power production forecasting; and (3) amend the *pro forma* OATT to add a generic ancillary service rate schedule, Schedule 10—Generator Regulation and Frequency Response Service, in which public utility transmission providers will offer to provide regulation service for transmission customers using transmission service to deliver energy from a generator located within a public utility transmission provider's balancing authority area.[36] The Commission preliminarily concluded that the proposed rules are necessary to ensure that

[36] Throughout this Final Rule the term Balancing Authority is used as defined by the North American Electric Reliability Cooperation (NERC). NERC, Glossary of Terms, available at http://www.nerc.com/files/Glossary_of_Terms_2012January11.pdf.

rates for Commission-jurisdictional services are just and reasonable and to remedy undue discrimination in existing transmission system operations.[37]

B. Comments

26. Some commenters take issue with the Commission's authority to mandate the tariff amendments contained in the Proposed Rule. With regard to forecasting and 15-minute scheduling, EEI and Southern assert that the Proposed Rule does not articulate a sufficient basis for changing existing tariff-based scheduling requirements under section 206 of the FPA.[38] Specifically, EEI and Southern question whether the Commission is relying upon record findings to support these proposed requirements. EEI and Southern submit that sections 205 and 206 "are simply parts of a single statutory scheme under which all rates are *established initially by the* [public utilities], by contract or otherwise ... Thus, FERC plays an essentially passive and reactive role under section 205."[39] EEI and Southern maintain that these types of decisions should be left to public utility

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[37] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 23.

[38] EEI and Southern argue, for example, that the Commission must rely upon factual, record findings to support these proposed mandates. EEI (citing *National Fuels v. FERC*, 468 F.3d 831, 839-44 (D.C. Cir. 2006)); Southern (citing, e.g., *National Fuels*, 468 F.3d 831, 839-44).

[39] EEI (citing *Atlantic City v. FERC*, 295 F.3d 1,21 (D.C. Cir. 2002) (quoting *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332341 (1956) and *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)); Southern (citing *Atlantic City v. FERC*, 295 F.3d 1,21 (D.C. Cir. 2002) (quoting *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp*, 350 U.S. 332341 (1956) and *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

transmission providers and RTOs and should be informed by regional conditions and not dictated on a generic basis.

27. In contrast, NextEra states that assertions that there is no record evidence not only ignore how current rules disadvantage VERs, but misunderstand the Commission's authority to promulgate rules of general applicability. NextEra points out that the Commission does not have to find that the tariffs or practices of every utility under its jurisdiction are unjust and unreasonable in order to proceed with a rulemaking. Rather, NextEra asserts that courts have confirmed that the Commission is not required to make individual findings when it exercises its statutory authority to promulgate a rule of general applicability.

28. Certain commenters also question the Commission's reliance in this proceeding on its authority to remedy undue discrimination.[40] Specifically, EEI and Southern take issue with the Commission's conclusion that procedures (such as hourly scheduling) applied uniformly to all transmission customers are unduly discriminatory under the FPA when those procedures arguably have a disparate impact on different types of transmission customers and/or place those customers at a competitive disadvantage in wholesale markets. EEI and Southern submit that the Commission and the D.C. Circuit have rejected the notion that facially-neutral technology and customer-blind transmission scheduling procedures are unduly discriminatory under section 205 of the FPA because

[40] *E.g.*, Southern; EEI.

of the effects or impacts of those requirements on different customer groups.[41] EEI asks the Commission to clarify that facially-neutral, technology- and customer-blind operational practices will not be deemed unduly discriminatory solely by virtue of disparate impact on dissimilar technologies or customers, and that the Proposed Rule is not intended as a departure from precedent in determining undue discrimination.

29. Similarly, Public Power Council questions the sufficiency of the Commission's evidence of undue discrimination against VERs. Public Power Council asserts that the Commission has not demonstrated that the costs of capacity charged to VERs were not incurred for the benefit of VERs, or would not have been incurred but for the needs of VERs, and that the costs of capacity were not prudently incurred. Public Power Council submits that the rules applicable to generation for the payment of balancing capacity costs are facially neutral, as VERs require more balancing capacity than non-variable resources. According to Public Power Council, if a load's characteristics required extraordinary amounts of balancing capacity, it seems unlikely that it or anyone else would complain that the rules should be changed to reduce costs. Thus, Public Power Council argues that a federal policy to promote renewable generation cannot be translated into an overriding mandate to prefer VERs.

30. ELCON asserts, with regard to 15-minute scheduling, forecasting, and Schedule 10 service, that the principle flaw in the Proposed Rule is its reliance on the supposition

[41] Southern (citing *Enron Power Marketing, Inc. v. FERC*, 296 F.3d 1148 (D.C. Cir. 2002) (*Enron*)); EEI (citing *Enron*, 296 F.3d 1148).

that operating practices favoring the dispatchability of resources are a form of "preferential treatment," and therefore that non-dispatchable resources such as VERs are being discriminated against. ELCON explains that the proposals set forth in the Proposed Rule are costly measures that would apply preferentially to just one class of generation – VERs – seeking to address discrimination that does not actually exist.

31. Southern asserts that, in instances where a single rate is found to have disparate cost impacts upon dissimilar customers, such a result is only considered unduly discriminatory if such differences cannot be cost-justified.[42] Southern argues that existing scheduling and imbalance practices are not unduly discriminatory against VERs. Southern explains that VER customers pay more energy imbalance charges than others because they impose more imbalance burdens and costs upon the system.[43] Similarly, ELCON maintains that the cost causation model of cost allocation results in greater economic efficiency by retaining a direct tie between the costs and the benefits of a given project. ELCON argues that in the instant case, there is no tie to the costs customers will be forced to bear.

32. Midwest ISO Transmission Owners contend that all generation resources should be treated on a comparable basis, and none should be subject to undue discrimination or

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[42] Southern (citing *Ala Elec. Coop. v. FERC*, 684 F.2d 20, 29 (D.C. Cir. 1982)(*Alabama Power*)).

Southern further contends that VERs are not similarly situated to dispatchable generation for scheduling and imbalance purposes. *Id.* (citing *City of Vernon v. FERC*, 845 F.2d 1042, 1045-46 (D.C. Cir. 1988)).

receive an undue preference. Midwest ISO Transmission Owners state that in the Midwest ISO this will mean that VERs are subject to the same requirements as existing resources unless additional requirements are necessary to maintain reliability.[44] ELCON argues that the Commission should apply a principle of "source neutrality," which it contends will create a level playing field for all alternative resources including demand response and combined heat and power. ELCON explains that, without the adoption of a resource planning paradigm based on source neutrality, almost any non-traditional resource may fall prey to undue discrimination with respect to transmission of electric energy and sales of electric energy for resale in interstate markets.

33. On the contrary, NextEra argues that most market rules are not oriented to aiding VERs, and may in fact present obstacles to VERs. NextEra states that, even in RTO markets, the fundamental principles around which markets are designed are day-ahead schedules, economic dispatch, and the impact of congestion. NextEra points out that none of these concepts are particularly applicable to VERs, which can have difficulty producing accurate day-ahead forecasts, are not truly dispatchable, and have limited ability to choose sites to reduce congestion. For example, NextEra contends that while nodal representation of generators may work best for dispatchable units, a system that was designed around non-dispatchable VERs could include features such as aggregation

[44] Midwest ISO Transmission Owners (referencing Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at PP 37, 45, 55 (stating that proposed reforms in intra-hour scheduling and power production forecasting can enhance reliability).

and scheduling from a portfolio of generators that might be staggered geographically, so as to reduce variability and forecasting errors and allow pooling of energy imbalances and deviations.

34. NextEra explains that when the Commission remedies unfair rules and practices, it is not doing so to create a preference for the type of entity that was being harmed, but rather to benefit the market and consumers. Thus, NextEra maintains that Commission action to provide greater flexibility, promote innovation or foster participation by new market entrants will ultimately benefit energy markets and consumers, even though the measure itself focuses on changes or incentives for one type of market participant.

35. Finally, with regard to meteorological forecasting in particular, Southern contends that such forecasting practices are beyond the scope of the Commission's authority. Southern states that courts have recognized that the Commission "is a 'creature of statute,' having no constitutional or common law existence or authority, but only those authorities conferred upon it by Congress."[45] Southern contends that public utilities have long engaged in meteorological forecasting for load forecasting and dispatch purposes. Southern argues that there never has been an indication that such practices were within the scope of the Commission's jurisdiction, and the advent of VER generation has not added such forecasting to the scope of the Commission's authority.

[45] Southern (citing *Cal. Indep. Sys. Operator Co. v. FERC*, 372 F.3d 395, 398 (D.C. Cir. 2004) (citing *Atlantic City Elec. Co. v. FERC*, 295 F.3d at 8)).

C. Commission Determination

36. The Commission concludes that it has authority under section 206 of the FPA to adopt the reforms set forth in this Final Rule. Section 313(b) of the FPA makes Commission findings of fact conclusive if they are supported by substantial evidence.[46] When applied in a rulemaking context, "the substantial evidence test is identical to the familiar arbitrary and capricious standard."[47] The Commission thus must show that a "reasonable mind might accept" that the evidentiary record here is "adequate to support a conclusion,"[48] that this Final Rule is needed to address barriers to the integration of VERs by remedying challenges that may be causing undue discrimination and increased costs ultimately borne by consumers. As explained below, the Commission has met its burden.

37. As discussed throughout this Final Rule, the reforms adopted in this proceeding are intended to ensure that rates for jurisdictional services remain both just and reasonable and are not unduly discriminatory or preferential. In this way, the reforms contained in this Final Rule build on the work of Order No. 890, in which the Commission made several reforms to the *pro forma* OATT, in part because of a recognition that the mix of generation resources on the system was changing and that not

[46] 16 U.S.C. 825l(b).

[47] *Wisc. Gas Co. v. FERC*, 770 F.2d 1144, 1156 (1985); *see also Associated Gas Distrib. v. FERC*, 824 F.2d 981, at 1018 (D.C. Cir. 1987).

[48] *Dickenson v. Zurko*, 527 U.S. 150, 155 (1999).

all generation resources were similarly situated.[49] Like the reforms instituted in Order No. 890, the reforms adopted herein are designed to remedy deficiencies in existing requirements that can cause the rates, terms, and conditions of jurisdictional services to become unjust and unreasonable or unduly discriminatory or preferential.

38. The basis for adopting changes to the *pro forma* OATT and *pro forma* LGIA is discussed in the sections below addressing reforms to transmission scheduling practices and the reporting of meteorological data. There the Commission concludes that changes to scheduling practices are necessary in order to ensure that charges for generator imbalance service under schedule 9 of the *pro forma* OATT and for generator regulation service, as relevant, are just and reasonable and not unduly discriminatory. The Commission also concludes that, without the reporting requirements adopted herein, the terms of the *pro forma* LGIA may impair the ability of public utility transmission providers to develop and deploy power production forecasting, which in turn can lead to rates for jurisdictional services that are unjust and unreasonable or unduly discriminatory.

39. The Commission concludes that we have the authority to make these determinations under applicable precedent, including *National Fuel*. In that case, the

[49] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 2 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 5. The Commission further recognized that intermittent resources, such as wind power, have a limited ability to control their output, and that this limitation supports tailoring certain requirements to the special circumstances presented by this type of resource. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 663 (requiring that generator imbalance provisions account for the special circumstances presented by intermittent generators).

court found that the Commission had not met the substantial evidence standard when it sought to extend its Standards of Conduct that regulate natural gas pipelines' interactions with their marketing affiliates to their interactions with their non-marketing affiliates. The court noted that it had previously upheld the Standards of Conduct as applied to marketing affiliates because the Commission had demonstrated both a theoretical threat, namely that pipelines could grant undue preferences to their marketing affiliates, and substantial record evidence that such abuse had actually occurred.[50] In considering the Commission's order extending the Standards to non-marketing affiliates, the court found that the Commission had cited a theoretical threat of undue preference, but had not cited a single example of actual abuse by non-marketing affiliates. It concluded that instead of providing evidence of a real problem with respect to non-marketing affiliates, the Commission had relied either on examples of abuse by marketing affiliates, and therefore already covered by the old Standards, or on comments from the rulemaking that merely reiterated a theoretical potential for abuse.[51] The court remanded the matter and noted that if the Commission chose to proceed with promulgating the new Standards, it would have to develop a factual record to support them. If the Commission decided instead to rely solely on a theoretical threat, it would need to show how this threat justified the costs that the Standards would create.[52]

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[50] *National Fuel*, 468 F.3d at 840.

[51] *Id.* at 841.

[52] *Id.* at 844.

40. Our actions in this Final Rule are consistent with the standards that the court set forth in *National Fuel*. We conclude that, in light of the increasing deployment of VERs on the nation's transmission system, the reforms adopted herein are necessary to correct operational practices that can limit the cost-effective integration of VERs into the transmission system consistent with open access principles. In other words, the problem that the Commission seeks to resolve represents a "theoretical threat," in the words of the *National Fuel* decision, the features of which are discussed throughout the body of this Final Rule in the context of each of the reforms adopted herein. This threat is significant enough to justify the reforms imposed by this Final Rule. It is not one that can be addressed adequately or efficiently through the adjudication of individual complaints.[53] In the terminology of *National Fuel*, the remedy we adopt is justified sufficiently by the "theoretical threat" identified herein, even without "record evidence of abuse." The actual experiences of problems cited in the record herein provide additional support for our action, but are not necessary to justify the remedy.

41. Citing *Enron*, Southern and EEI also argue that the Commission does not have the authority to remedy undue discrimination in situations where facially neutral operational practices result in a disparate impact on different market participants. The Commission disagrees. *Enron* involved an OATT Filing by a public utility (Entergy) in which the

[53] Individual adjudications by their nature focus on discrete questions of a specific case. Rules setting forth general principles are necessary to ensure that adequate processes are in place.

utility sought to require point-to-point transmission customers to designate specific sources and sinks for transmission service. The proposal also set forth what the utility would accept as a valid source or sink, prohibiting a generator (or generation-only control area) from being a sink, and prohibiting a load (or load-only control area) from being a source.[54] Customers objected to the proposal, arguing that the provision would not limit Entergy's ability to reserve capacity and schedule in and out of its control area because it had load and generation within its control area, but would prohibit similar transactions from customers operating control areas completely surrounded by Entergy that sought to set up transactions in and out of those control areas. The Commission evaluated Entergy's proposal under the applicable standard of review, i.e., whether the OATT Filing was consistent with or superior to the Order No. 888 *pro forma* OATT. The Commission accepted the proposal, and the United States Court of Appeals for the District of Columbia Circuit upheld the decision.[55]

42. We find that commenters' reliance on *Enron* is misplaced. In *Enron*, the Commission reviewed a tariff filing made under section 205 of the FPA to determine if it was consistent with or superior to the *pro forma* OATT. The scope of that analysis is not analogous to that of our inquiry in this proceeding, which is to determine if changes to the *pro forma* OATT and *pro forma* LGIA are necessary to ensure that rates for

[54] *Enron*, 296 F.3d at 1151.

[55] *Id.* at 1153-54.

jurisdictional services remain just and reasonable and not unduly discriminatory. In any event, to the extent that *Enron* may be relevant to a rulemaking proceeding of general applicability, Southern and EEI appear to misunderstand the result in *Enron*. In that case, the court found that it was neither arbitrary nor capricious for the Commission to accept a tariff provision forbidding the designation of a generator-only control area as a sink and a load-only control area as a source as comparable to the *pro forma* OATT.[56] In addition to this holding, the court indicated that it was sufficient for the Commission to address comparability of an OATT (the applicable standard in that proceeding) "on the basis of the terms and conditions offered to customers, not on the usefulness of those terms and conditions to a particular customer because of that customer's capacities and needs," noting also that the Commission found that the provision was not discriminatory.[57]

43. *Enron* did not, as Southern and EEI suggest, reject the notion that facially-neutral, technology- and customer-blind operational practices could be found to be unduly discriminatory because of the effects or impacts of those requirements on different customer groups. Instead, the relevant *Enron dicta* indicate that the Commission *could* sustain a determination that a tariff provision is comparable to the *pro forma* OATT where it offers the same terms and conditions to customers, notwithstanding a difference

[56] *Id.* at 1151-52.

[57] *Id.* at 1151. The court further found that the Commission adequately addressed charges that the provision would lead to discriminatory treatment by accepting the utility's commitment to apply the provision on a nondiscriminatory basis.

in how different customers will use or benefit from those tariff provisions.[58] However, nothing in *Enron* mandates that result.

44. Our conclusion that Southern and EEI erred in their interpretation of *Enron* is bolstered by other cases included in the comments of both parties. For example, Southern and EEI cite *Alabama Power* for the proposition that, in instances where a single rate is found to have disparate cost impacts on dissimilar customers, such a result is only considered unduly discriminatory if the differences cannot be cost justified.[59] In *Alabama Power*, the issue for the court was whether an application of the *same* rate to two groups of customers that were similar in many respects may nevertheless violate statutory prohibitions against unduly discriminatory rate schemes. That case involved rate filings by a utility that applied the same rate to two groups of wholesale service customers. One group alleged that this single rate represented a misallocation of costs, resulting in that group paying significantly more (and the other paying significantly less) than the costs for which its members were responsible. The court held that notwithstanding the fact that the same rate applied to both groups of customers, the Commission was obligated to evaluate whether the different costs imposed by those two groups rendered the use of a single rate unduly discriminatory.[60]

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[58] *Id.*

[59] Southern (citing *Alabama Power*, 684 F.2d at 29); EEI (citing *Alabama Power*, 684 F.2d 20).

[60] *Alabama Power*, 684 F.2d at 28-29.

45. Southern argues that a finding in the Proposed Rule—that existing hourly transmission scheduling protocols expose transmission customers to "excessive or unduly discriminatory generator imbalance charges"—may run afoul of *Alabama Power* because VER customers require greater amounts of imbalance service and therefore should be required to pay more in the way of imbalance charges.[61] Southern and EEI contend that, because VERs are not similarly situated to dispatchable generation for scheduling and imbalance purposes, existing scheduling and imbalance practices cannot be unduly discriminatory toward VERs.[62] Similarly, ELCON argues that the Proposed Rule would require all ratepayers to subsidize the integration of VERs despite not receiving any benefits, thereby violating cost causation principles.

[61] Southern (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 37).

[62] Both Southern and EEI cite additional authority for this point, i.e., that in order to demonstrate that it was unduly discriminated against, a party must show that it is similarly situated to another party receiving different treatment. *See* EEI (citing *Ark. Elec. Energy Consumers v. FERC*, 290 F.3d 362 (D.C. Cir. 2002) ("a rate is not 'unduly' preferential or 'unreasonably'" discriminatory in violation of the FPA if disparate effect of transmission or sale of electric energy by the jurisdictional utility can justify the disparate effect")); Southern (citing *City of Vernon v. FERC*, 845 F.2d 1042, 1045-46 (D.C. Cir. 1988) ("The Commission's opinion sets forth a two-part test for discriminatory treatment where different rates or services are offered, requiring a showing that the unequally treated customers are 'similarly situated,' and that the service sought is the 'same service' actually offered elsewhere.") & n.2 ("FERC has typically relied on factors like these in defining a prima facie case of undue discrimination."); *see,* e.g.,*Sacramento Mun. Util. Dist. v. FERC*, 474 F.3d 797, 802 (D.C. Cir. 2007) ("In order for PG&E's refusal to negotiate a successor agreement with [Sacramento Municipal Utility District (SMUD)] to constitute undue discrimination, SMUD must demonstrate it is similarly situated to Western.").

46. As with commenters' reliance on *Enron*, we find that commenters' reliance on *Alabama Power* is misplaced. The Commission is not determining whether a single rate imposed on two groups of customers may unduly discriminate against one of those groups. Instead, the Commission is promulgating a generic rule that amends the scheduling requirements of the *pro forma* OATT to remedy practices throughout the industry that may be causing jurisdictional rates to be excessive or unduly preferential. Accordingly, the task before the Commission is not comparing the impact of a concrete rate proposal on distinct and readily identifiable customers or classes. Rather, the Commission is broadly evaluating whether the *pro forma* OATT contains the appropriate set of requirements to ensure that rates for all customers remain just and reasonable and not unduly discriminatory. As in Order No. 890, the Commission is acting in part to remedy OATT provisions that may allow public utility transmission providers to treat some customers in an unduly discriminatory manner. Such an endeavor necessarily requires the Commission to take notice of the general developments in the electric industry in deciding what generic reforms may be needed to ensure that the *pro forma* OATT does not unduly discriminate against any one class of customers.[63]

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[63] *See Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000) (TAPS) (affirming Order No. 888 rulemaking based on general findings, rejecting utility arguments that FERC must have substantial evidence and make specific factual findings); *Wisc. Gas Co. v. FERC*, 770 F.2d 1144 (affirming that Commission need not make individual findings regarding each affected entity but can rely on a broader record in promulgating rule of general applicability); *Associated Gas Distrib. v. FERC*, 824 F.2d 981 (affirming that the Commission is not required to have empirical data for all the propositions upon which its order depended before promulgating a rule).

47. In Order No. 890, the Commission recognized that the mix of generation resources on the system was changing and that not all generation resources were similarly situated.[64] In response, the Commission instituted reforms that recognized the unique nature of intermittent resources, tailoring certain requirements to the special circumstances presented by this type of resource.[65] We again recognize that VERs, by definition,[66] are not similarly situated to conventional, dispatchable generators and that reforms to the *pro forma* OATT are necessary to ensure that these resources are treated in a fair and not unduly discriminatory manner. Simply because VERs are not similarly situated in all respects to conventional, dispatchable generators, it does not follow, as Southern and EEI assert, that existing *pro forma* OATT provisions that place a disproportionate burden on VERs are just and reasonable.[67] The more frequent scheduling intervals required by this Final Rule will enable VERs, as well as other generators, to schedule transmission service accurately based on forecasted energy output. This will mitigate VERs' exposure to imbalance charges, while at the same time

[64] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 5.

[65] *Id.* P 663 (requiring that generator imbalance provisions account for the special circumstances presented by intermittent generators).

[66] *See supra* note 1 (defining VER).

[67] *See Alabama Power*, 684 F.2d at 23-24 ("It matters little that the affected customer groups may be in most respects similarly situated—that is, that they may require similar types of service at similar (even if varying) voltage levels. If the costs of providing service to one group are different from the costs of serving the other, the two groups are in one important respect quite dissimilar.").

giving public utility transmission providers a better understanding of expected energy flows on their systems.

48. The Commission does not need to make specific findings with respect to each affected entity so long as the agency's factual determinations are reasonable.[68] As further discussed herein, the Final Rule amends the *pro forma* OATT in ways that will limit uncertainty and provide additional control over scheduling, which should reduce imbalance charges for all customers. The proposed reforms will further benefit customers and the market as a whole by providing increased flexibility and encouraging innovation and participation by new market participants.[69] While the Commission commenced this proceeding as a response to the significantly increasing penetration of VERs into the nation's generation portfolio, the Commission's purpose is not to favor VERs over other forms of generation (or demand) resources. Quite the contrary, a primary goal of this proceeding is to remove obstacles that can have a discriminatory

[68] TAPS, 225 F.3d at 688 (citing *Wisc. Gas Co. v. FERC*, 770 F.2d at 1158).

[69] *Cf.* Order No. 679, *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, at PP 131, 176, 224, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, at P 77 (2006), *order on reh'g*, Order No. 679-B, 119 FERC ¶ 61,062 (2007). The Commission does not authorize these measures to provide a unilateral benefit to transmission owners but rather to encourage the development of needed transmission, which has broader benefits to the market and consumers.

impact on the ability of VERs to compete in the marketplace and that can otherwise result in unjust and unreasonable rates for all market participants.[70]

49. Finally, in response to Southern, the Commission notes that it is not asserting jurisdiction over the practice of power production forecasting in this Final Rule. Rather, the Commission is adopting changes to the *pro forma* LGIA to impose reporting requirements on interconnection customers whose generating facilities are VERs. As discussed in further detail later in this Final Rule, power production forecasting can be used by public utility transmission providers to significantly reduce operating costs associated with the integration of VERs interconnected to their systems.[71] However, the ability of public utility transmission providers to engage in power production forecasting may be limited without data from interconnected VERs. In order to facilitate a public utility transmission provider's use of power production forecasting to reduce its operating costs, the Commission is amending the requirements of the *pro forma* LGIA to impose a data reporting requirement as a condition of interconnection service for interconnection customers whose generating facilities are VERs.

50. The question then is whether the Commission has jurisdiction to condition the grant of interconnection service on the reporting of meteorological and outage data by interconnection customers whose generating facilities are VERs as a practice affecting

[70] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 23.

[71] *See infra* § IV.B.1 (Data Requirements).

rates subject to the Commission's jurisdiction under the FPA.[72] As the Commission explained in Order No. 2003, interconnection service is a component of open access transmission service, subject to the Commission's regulation under sections 205 and 206 of the FPA.[73] The reporting of meteorological and outage data by VER customers taking jurisdictional interconnection service has a direct affect on the ability of the public utility transmission provider to efficiently manage the VER integration through the development and deployment of power production forecasting. Failure to require the reporting of this data could limit the public utility transmission provider's ability to develop and deploy power production forecasts and, in turn, its attempts to efficiently commit or de-commit resources providing regulation reserves, potentially resulting in rates for reserve-related services that are unjust and unreasonable or unduly discriminatory. It is therefore reasonable for the Commission to conclude that it is within our jurisdiction to implement the data reporting requirements of this Final Rule as a condition of interconnection service.

IV. Proposed Reforms

A. Intra-hour Scheduling

51. The first of the two reforms adopted in this Final Rule relates to the intervals at which transmission customers may submit transmission schedules under the *pro forma*

[72] *See Cal. Indep. Sys. Oper. v. FERC*, 372 F.3d 395 (D.C. Cir. 2004).

[73] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at 12.

OATT. As discussed below, the Commission amends the *pro forma* OATT to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals. The Commission concludes this change to existing operational practices is necessary in order to ensure that charges for generator imbalance service under Schedule 9 of the *pro forma* OATT and for generator regulation service, as relevant, are just and reasonable and not unduly discriminatory.

1. Intra-Hour Scheduling Requirement

a. Commission Proposal

52. In the Proposed Rule, the Commission preliminarily found that hourly transmission scheduling protocols are no longer just and reasonable and may be unduly discriminatory as the default scheduling time periods required by the *pro forma* OATT. Specifically, the Commission preliminarily found that existing hourly transmission scheduling protocols expose transmission customers to excessive or unduly discriminatory generator imbalance charges and are insufficient to provide system operators with the flexibility to manage their system effectively and efficiently. Therefore, the Commission proposed to amend sections 13.8 and 14.6 of the *pro forma* OATT to provide transmission customers the option to schedule transmission service on an intra-hour basis, at intervals of 15 minutes. The Commission noted that its proposed

reform would allow for intra-hour scheduling adjustments and that it did not propose changes to the hourly transmission service reservation provided in the OATT.[74]

53. The Commission acknowledged in the Proposed Rule that a number of public utility transmission providers already have begun implementing intra-hour scheduling practices. The Commission stated that, while these individual reforms are important steps toward the efficient integration of VERs, it believed that it also is important to establish 15-minute scheduling periods as the default scheduling process. At the same time, the Commission acknowledged arguments that regional differences should be respected when developing an implementation process and that any Commission action should not negatively affect ongoing industry efforts. In that regard, the Commission sought comment on the best approach for implementing the proposed intra-hour scheduling reforms. The Commission recognized that an optimal implementation approach should support ongoing industry efforts and may consider regional differences, such as the amount of VERs present in that region. In proposing implementation approaches, the Commission encouraged commenters to consider any impacts on transmission customers scheduling across multiple systems and whether these impacts diminish the benefits of implementing intra-hour scheduling.[75]

[74] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 39 & n.89.

[75] *Id.* PP 42-43.

54. To understand more fully the modifications that this proposed reform may require, the Commission sought comment on the specific hardware, software, and personnel changes that are necessary to implement intra-hour scheduling. The Commission further inquired as to whether there would be any additional impacts on relatively small public utility transmission providers, and how to best facilitate this reform for small public utility transmission providers.

b. Comments

i. Obligation to Offer Intra-Hour Scheduling

55. A number of commenters support the Commission's proposal to require public utility transmission providers to offer intra-hour scheduling,[76] although some seek clarifications or modifications of the proposal. Additionally, commenters disagree as to the appropriate period of time for submitting intra-hour schedules. These commenters generally agree that intra-hour scheduling would enable transmission customers to align transmission schedules with actual generation output more effectively, reduce the need for transmission providers to carry expensive operating reserves, and provide for greater system flexibility by utilizing available resources in a more efficient manner.

[76] *E.g.*, A123; Alstom Grid; ACSF; Argonne National Lab; BP Energy; California ISO; CESA; CMUA; CEERT; Center for Rural Affairs; Clean Line; CGC; Defenders of Wildlife; Environmental Defense Fund; EPSA; Exelon; First Wind; FriiPwr; Independent Power Producers Coalition–West; Independent Energy Producers; ITC Companies; NextEra; NaturEner; Organization of Midwest ISO States; Oregon and New Mexico PUC; Public Interest Organizations; Powerex; SWEA; Tacoma Power; Tres Amigas; TVA; Vestas; Viridity Energy; Vote Solar; Western Grid; Xcel.

56. For example, EPSA states that the option of 15-minute scheduling would expand the availability of flexible generation resources and demand response resources to provide additional liquidity and consistency in the market. Exelon argues that implementing intra-hour scheduling will reduce supply-side uncertainty, which should allow resources to be more optimally selected and allocated than otherwise would be the case. Powerex contends that shorter scheduling intervals would allow the use of more accurate forecasts that are closer to the operating time-frame. Joined by CEERT and others, Powerex argues that intra-hour scheduling would increase transmission system flexibility and efficiency, providing grid operators with more options for scheduling resources during each hour and decreasing the need for (and costs of) ancillary services needed for reliable integration of VERs.[77] The Center for Rural Affairs asserts that making intra-hour scheduling available is essential for public utility transmission providers and balancing authorities seeking to provide system balance with increasing generation from VERs.

57. While acknowledging that some stakeholders in this proceeding oppose the mandatory nature of the Commission's proposal, disagree about scheduling costs, and question the reliability impacts of the proposed reforms, Public Interest Organizations state that almost all stakeholders have acknowledged that intra-hour scheduling does improve scheduling accuracy and decrease the need for energy imbalance services.

[77] *E.g.*, CEERT; Powerex; Public Interest Organizations; Vestas.

Public Interest Organizations, joined by Environmental Defense Fund and Argonne National Lab, contend that intra-hour scheduling, as compared to hourly scheduling protocols, allows for a more accurate prediction of the variable generation that can be delivered within the market interval, reducing the need to procure expensive regulation or energy imbalance services.[78] NaturEner agrees, arguing that shorter scheduling intervals would allow for more frequent generation adjustments, thus, decreasing the negative impacts on both the transmission system and the grid from frequent generation disruptions. Iberdrola similarly contends that moving toward smaller intra-hour scheduling intervals will provide incentives for more complete and efficient scheduling practices and eliminate other outdated and discriminatory operating practices.

58. California ISO states that continuing to require resources to match hourly transmission schedules would perpetuate inefficient and burdensome operational requirements. Tres Amigas contends that current scheduling practices have been associated with underutilized transmission assets and sub-optimal operating practices resulting in inefficient curtailment of generation. BP Energy asserts that 15-minute scheduling intervals will increase the ability of a transmission customer scheduling energy from a VER to manage the scheduled input and, therefore, its imbalance costs. Vestas notes that all generators, regardless of fuel type, will be able to track their schedules more closely with actual levels of production as a result of intra-hour

[78] *E.g.*, Argonne National Lab; Environmental Defense Fund; Public Interest Organizations.

scheduling. Vestas explains that, if a large fossil-fueled resource suffers an outage or derate within an hour, the ability to change its schedule earlier than the next clock hour can provide significant benefits to both the generator and the transmission system operator. Clean Line contends that intra-hour scheduling is likely to have benefits independent of variable generation integration, stating that sub-hourly variations in load could be managed in a more cost-effective manner. Also, A123 contends that shorter scheduling intervals will help OATT markets incorporate the benefits of high-ramp, limited energy resources like storage.[79]

59. However, other commenters oppose mandatory intra-hour scheduling, arguing generally that current scheduling practices are neither preferential nor unduly discriminatory.[80] For example, ELCON states that the Commission's proposals are costly measures that would apply preferentially to just one class of generation–VERs–in order to address discrimination that does not actually exist. Some commenters argue that further study of the need for intra-hour scheduling should be undertaken prior to mandating the practice. Several of these commenters assert that the Commission should not require the implementation of 15-minute intra-hour scheduling until certain impacts

[79] A ramp rate is the rate, expressed in megawatts per minute, that a resources changes its output. *See* NERC Glossary of Terms, available online at http://www.nerc.com/files/Glossary_of_Terms.pdf.

[80] *E.g.*, ELCON; Midwest ISO; NV Energy; Southern.

are better understood.[81] LADWP submits that intra-hour scheduling should not be implemented until it has been fully vetted and researched to assess operational capabilities and coordination.

60. Some commenters argue that the Commission's proposed reform may not lead to a reduction in aggregate reserve costs. These commenters contend that the implementation of intra-hour scheduling does not negate the inherent variability of VERs and, therefore, the cost of providing balancing services is merely shifted, rather than mitigated, by intra-hour scheduling.[82] For example, Avista explains that, while the host balancing authority will provide a reduced amount of balancing reserves within each scheduling period, a significant portion of this variability is being covered by the sink balancing authority or the load serving entity (LSE). Avista contends the sink balancing authority or LSE will incur increased balancing costs to follow the fluctuating VER schedule against a relatively more constant load, thereby shifting the cost of managing that variability as opposed to creating substantial cost savings through intra-hour scheduling. If the host balancing authority area and the sink balancing authority area are the same, Avista argues that no cost savings or reduction in reserves is accomplished by the proposed scheduling reforms. Iberdrola argues that implementing intra-hour scheduling absent a market for dispatchable resources to manage variability could potentially be more harmful than

[81] *E.g.*, California PUC; LADWP; NorthWestern; NV Energy; Pacific Gas & Electric.

[82] *E.g.E.g.*, Avista; Bonneville Power; M-S-R Public Power Agency; Xcel.

helpful to VER integration. Duke argues that, due to the inherent variability of VERs, more regulating reserves will be needed regardless of the scheduling interval. While operating experience may diminish the need for regulating reserves over time, Duke contends that the level of regulating reserves will ultimately be maintained at a higher level than required today. M-S-R Public Power Agency encourages the Commission to consider the effectiveness of reducing overall intermittency management obligations further before implementing an intra-hour scheduling reform.

61. With regard to the appropriate time interval for intra-hour scheduling, a number of commenters support the Commission's proposal to require public utility transmission providers to offer intra-hour scheduling at 15-minute intervals.[83] Many of these commenters agree that a scheduling interval of 15-minutes or shorter provides a number of benefits such as lowering the costs related to integrating VERs into the market and operational benefits. Argonne National Lab states that requiring transmission providers to schedule resources with a frequency of at least every 15 minutes would provide benefits to all supply and demand resources in the power system, not only VERs. Several commenters argue that scheduling in 15-minute intervals would reduce imbalance

[83] *E.g.*, A123; Alstom Grid; ACSF; Argonne National Lab; BP Companies; CESA; CEERT; Center for Rural Affairs; Clean Line; CGC; Defenders of Wildlife; Environmental Defense Fund; EPSA; Exelon; First Wind; Independent Energy Producers; ITC Companies; NaturEner; Organization of Midwest ISO States; Oregon & New Mexico PUC; Powerex; Public Interest Organizations; SWEA; Tres Amigas; Viridity Energy; Vote Solar; Western Grid; Xcel.

charges through more accurate schedules.[84] EPSA notes that the proposed 15-minute scheduling interval is consistent with NERC recommendations for achieving greater flexibility while meeting relevant reliability requirements.[85] Exelon asserts that 15-minute scheduling is an industry best practice and that the Commission should set a deadline by which all transmission providers must conform.

62. Vestas acknowledges that a shortened scheduling interval must strike a balance between the benefits of increased certainty and reduced variability resulting from customers' ability to more closely match their schedules with their anticipated output and any increased complexity and technical issues that could result if the scheduling interval is too short. Vestas contends that a 15-minute scheduling window provides a reasonable compromise between the current hour and the even shorter 5-minute intervals utilized in certain RTO markets. Oregon & New Mexico PUC agree that as more wind and solar generation are integrated into the system, shorter intra-hour intervals will generate greater cost savings than longer intervals. Oregon & New Mexico PUC urge the Commission to adopt a minimum standard for transmission scheduling at 15-minute intervals to focus industry efforts on implementing a consistent standard rather than debating the appropriate interval.

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[84] *E.g.*, BP Energy; CEERT; CGC; Defenders of Wildlife; Duke; NextEra; Public Interest Organizations; SEIA; Vestas; Xcel.

[85] EPSA (citing NERC April 12, 2010 Response to NOI at 17-18).

63. Some commenters are concerned that the proposed 15-minute scheduling interval is too long.[86] While supportive of 15-minute scheduling as an interim step, several commenters recommend that the Commission require public utility transmission providers to move to shorter scheduling intervals.[87] RenewElec asserts that 15-minute scheduling may not be sufficient for the integration of large amounts of VERs. As an option for increasing flexibility without decreasing the 15-minute scheduling period, SEIA asks the Commission to clarify that generators may submit 15-minute schedules with different output levels at the beginning and end of the 15-minute period to reflect anticipated ramps to manage the variations in diurnal ramping of solar resources. Vote Solar echoes the concerns of SEIA with regard to solar diurnal ramping and argues for scheduling intervals more granular than 15-minutes to accommodate wide-area balancing. Vote Solar recommends that the Commission additionally require a 5-minute intertie scheduling interval. However, EEI cautions that if the Commission decides to move forward with the rule as proposed, the scheduling interval should be no less than 15-minutes as it may undermine the reliable operation of the system.

[86] *E.g.*, Environmental Defense Fund; FriiPower; Independent Power Producers Coalition-West; RenewElec; SEIA; Vestas.

[87] *E.g.*, Environmental Defense Fund; Independent Power Producers Coalition-West; RenewElec.

64. Other commenters argue that the proposed 15-minute scheduling interval is too short.[88] Several commenters recommend an initial 30-minute intra-hour scheduling interval to coincide with current regional initiatives or as a general first step.[89] Some commenters argue that the Commission should use the output of ongoing regional initiatives to determine whether a 15-minute scheduling interval is necessary, or whether another mechanism is the desired method to reduce VER integration costs.[90] EEI states that, if there is no demand for intra-hour scheduling, investments to implement 15-minute scheduling would be unnecessary. NorthWestern expresses uncertainty as to whether 15-minute scheduling would provide benefits greater than those achieved through 30-minute scheduling. Southern California Edison suggests that a 30-minute scheduling interval is sufficient as it can capture forecast error reductions, align with the commitment capabilities of most integrating resources, and reduce the need for additional administrative overhead. Iberdrola recommends that the Commission allow public utility transmission providers to provide intra-hour schedules at 30-minute intervals as an interim step to participation in an energy imbalance market.

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[88] *E.g.*, LADWP; Montana PSC; NV Energy; Puget.

[89] *E.g.*, Bonneville Power; California ISO; California PUC; CMUA; Montana PSC; NorthWestern; NV Energy; Snohomish County PUD; Southern California Edison; WUTC.

[90] *E.g.*, Bonneville Power; California PUC; CMUA; FirstEnergy; NorthWestern; Snohomish County PUD; Southern California Edison.

65. Some commenters contend that a 15-minute scheduling interval does not support the standard 20-minute generator/scheduling ramp rate in the West.[91] Tacoma Power explains that continuing to use 20-minute ramps would create interface problems with the receipt of schedules on a 15-minute interval. Bonneville Power similarly argues that scheduling on a 15-minute interval would result in almost continuous ramping in a way that 30-minute scheduling does not, and that the resulting reduction in dynamic transfer capability could preclude implementation of other options for reducing VER integration costs. WestConnect asserts that this may result in a disparity in the accurate scheduling of VERs and the system operator's ability to efficiently integrate VERs under restricted ramping intervals.

66. Bonneville Power and Xcel request clarification that "intra-hour scheduling adjustments" include both adjustments to existing schedules and the submission of new schedules.[92] MidAmerican requests clarification as to whether intra-hour scheduling is intended to be available only within the current hour or also in future hours.

ii. Consistency in Scheduling Requirements

67. Commenters differ regarding whether the Commission should adopt a consistent intra-hour scheduling requirement for all transmission providers under the *pro forma* OATT. If the Commission decides to move forward with its proposal, EEI recommends

[91] *E.g.*, LADWP; NorthWestern; PNW Parties; Tacoma Power; WestConnect.

[92] Bonneville Power; Xcel.

that the Commission require a uniform, consistent scheduling interval throughout each interconnection. EEI contends that this will allow for the development of uniform and consistent intervals in reliability standards and business practices and also promote accuracy of results. A number of other commenters agree that consistent scheduling intervals are needed in order for intra-hour scheduling to occur across balancing authority areas.[93] For example, NorthWestern and Southern contend that, unless all public utility transmission providers within an interconnection are required to comply with the same intra-hour scheduling interval, intra-hour scheduling may erode a utility's ability to maintain reliability.

68. Public Interest Organizations agree that there is a need to apply consistent scheduling obligations across the country in order to avoid undue discrimination against VERs and argue that the benefits of 15-minute intra-hour scheduling will apply throughout the system, not just to VERs. If the Commission decides to allow for a public utility transmission provider to propose variations to 15-minute scheduling, Public Interest Organizations suggest that the entity be required to demonstrate why a variation is necessary and show that the proposed alternative will be equally effective or superior to the Commission's proposal. NextEra points out that the arguments favoring regional variations in scheduling requirements ignore the fact that many regions have no overall

[93] *E.g.*, Argonne National Lab; EEI; Iberdrola; Independent Power Producers Coalition-West; NaturEner; NorthWestern; NRECA; Oregon & New Mexico PUC; Public Interest Organizations; Puget; Southern California Edison; Southern; and Tres Amigas.

regional body or authority with sufficient ability to ensure consistency in resolving issues regarding VER integration. NextEra submits that the Commission has ultimate responsibility to ensure that market rules are just and reasonable, and that the Commission cannot delegate its responsibility to states, regions, or public utilities. Tres Amigas requests that the Commission clarify that intra-hour scheduling will apply to all generation scheduled on the bulk transmission system; inter- and intra-balancing authority transactions, and point-to-point, network, or native load service. Tres Amigas states that inconsistent transmission scheduling periods will lead to inefficient and/or discriminatory use of the transmission system.

69. Many commenters contend that the Commission should afford public utility transmission providers the flexibility to determine how best to implement intra-hour scheduling in their region. These commenters ask the Commission to acknowledge that region-specific scheduling practices may be appropriate in light of system circumstances and market designs.[94] Several of these commenters note that there are regional efforts and pilot programs underway that are aimed at efficiently managing the integration of

[94] *E.g.*, Avista; Bonneville Power; California ISO; CMUA; California PUC; Detroit Edison; Dominion; EEI; FirstEnergy; Grant PUD; Idaho Power; Independent Power Producers Coalition-West; ISO/RTO Council; Midwest ISO; Montana PSC; National Grid; NorthWestern; NRECA; New York ISO; NV Energy; PJM; PNW Parties; Public Power Council; Puget; SMUD; Southern; Tacoma Power; WUTC; WestConnect.

VERs and providing an opportunity for intra-hour scheduling.[95] These commenters generally contend that the Commission should support and not undermine such regional initiatives. Examples of regional initiatives identified by commenters include the Joint Initiative,[96] the WECC Efficient Dispatch Toolkit,[97] and a pilot between Bonneville Power and the California ISO to evaluate the use of intra-hour scheduling on the California-Oregon Intertie.[98] Several commenters suggest that the Commission should

[95] *E.g.*, Avista; Bonneville Power; Business Council; California ISO; California PUC; CESA; CMUA; EEI; Idaho Power; Joint Initiative; Montana PSC; National Grid; NorthWestern; NV Energy; PNW Parties; Puget; SMUD; WestConnect.

[96] The Joint Initiative is a consensual, collaborative effort within the Western Interconnection to develop high-value and cost-effective regional products, identified through a stakeholder process, for implementation by interested parties. It is jointly sponsored by Columbia Grid, Northern Tier Transmission Group, and WestConnect. Joint Initiative at 1-3. Step one of the Products and Services Strike Team intra-hour scheduling initiative began in July 2011 with the scheduling of transmission in half hour increments. Step two includes broader application of intra-hour scheduling and scheduling in finer increments (15 or 20 minutes) only after evaluation that this step is necessary.

[97] The WECC Efficient Dispatch Toolkit contains: (1) an enhanced curtailment calculator that will aid in managing flows across constrained paths; and (2) an energy imbalance market that will efficiently dispatch resources in response to imbalance.

[98] This pilot program is intended to facilitate the export of wind resources located in Bonneville Power's Balancing Authority into the California ISO. The pilot will use dynamic e-tagging and communication to facilitate intra-hour schedule changes, beginning with a 30-minute scheduling interval.

conduct technical conferences to investigate the relative merits of these and alternative approaches prior to imposing a uniform national mandate.[99]

70. Some commenters express concern that a Commission mandate may detrimentally affect current regional efforts by diverting resources from or discouraging participation in voluntary regional initiatives by both jurisdictional and non-jurisdictional entities.[100] Bonneville Power and CMUA suggest that ongoing initiatives may provide the Commission with real-world data and alternative options to reach the Commission's stated goals. In order to support ongoing regional initiatives, Pacific Gas & Electric recommends that the Commission not implement 15-minute scheduling until regional initiatives have been given a reasonable amount of time to come to an end. Grant PUD argues that 20-30 minute scheduling intervals appear to be sufficient for the Northwest region of the country and that the Commission should allow this to be considered a "regional practice."[101] In addition, NRECA argues that the Commission should afford public utility transmission providers an opportunity to demonstrate that existing practices or practices under development are or will be consistent with or superior to the Commission's proposed reforms.

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[99] *E.g.*, California ISO; Grays Harbor PUD; Pacific Gas & Electric; SMUD; Snohomish County PUD.

[100] *E.g.*, Avista; Bonneville Power; California PUC; EEI; Idaho Power; National Grid; NorthWestern; NRECA; NV Energy; PNW Parties.

[101] Grant PUD at 4.

71. Some commenters stress the need for regional flexibility because, in their view, intra-hour scheduling may not be the right decision for everyone.[102] For example, LADWP asserts that the Proposed Rule is ill-timed, and that intra-hour scheduling may not be necessary in regions where the existing generation portfolio provides sufficient flexibility to integrate a fixed percentage of VER penetration reliably. Southwestern explains that, as a federal agency operating under a Congressional statutory mandate, the Administration may not be able to implement intra-hour scheduling as this may impact the purposes of the Corps projects such as flood control, hydropower, navigation, fish and wildlife, and recreation. If the Commission adopts the Proposed Rule, NRECA urges the Commission to permit public utility transmission providers to seek a waiver from implementing intra-hour scheduling until the entity receives a request to schedule intra-hour.

72. A number of commenters question the applicability of the proposed intra-hour scheduling requirements in regions with RTOs/ISOs, arguing that these markets already provide for system flexibility that is consistent with or superior to the intra-hour scheduling protocol proposed by the Commission.[103] Business Council suggests that the Commission should focus its attention on areas where rapid spot energy and ancillary

[102] *E.g.*, ISO/RTO Council; NorthWestern; Pacific Gas & Electric; PNW Parties; Public Power Council; Puget.

[103] *E.g.*, AWEA; California ISO; California PUC; Detroit Edison; Iberdrola; ISO New England; Massachusetts DPU; Midwest ISO; PJM; Public Interest Organizations; RENEW; Sunflower and Mid-Kansas; Western Farmers.

service markets do not exist, particularly non-RTO/ISO areas that are experiencing significant renewable energy penetration. ISO/RTO Council asks the Commission to recognize that different regions currently provide varying levels of flexibility to VERs through different systems and market mechanisms, suggesting that the Commission craft the Final Rule in a manner that allows transmission providers to work with their stakeholders to develop solutions that work for their region. FirstEnergy asserts that each RTO and ISO, through its stakeholder process, should be given the opportunity to evaluate the potential need for, and benefits and costs associated with, intra-hour scheduling. Sunflower and Mid-Kansas similarly argue that the Final Rule should recognize the differences between organized markets and not group them with non-RTO public utility transmission providers. Environmental Defense Fund asserts that, because some RTOs and/or balancing authorities have begun to implement regional scheduling reforms, the Commission should avoid imposing duplicative requirements or obstructing such efforts.

73. Some commenters suggest that the Commission clarify that its proposed intra-hour scheduling reforms apply only to RTOs and ISOs in the context of transactions between balancing authorities.[104] However, National Grid cautions the Commission against overly-prescriptive requirements for scheduling between regions and asks for clarification that public utility transmission providers are permitted to pursue other

[104] *E.g.*, AWEA; Iberdrola; Public Interest Organizations; and RENEW.

scheduling improvements for cross border transactions and inter-tie scheduling. National Grid notes that New York ISO and ISO New England are already working on solutions to improve interregional interchange scheduling. ISO/RTO Council states that accelerated scheduling changes may negatively affect RTO and ISO interchanges with non-market areas, as those smaller areas may be unable to keep up with an RTO or ISO scheduling within the hour.

74. Many commenters express concern regarding the potential for seams issues, particularly with transmission providers that are not subject to the Commission's ratemaking jurisdiction under sections 205 and 206 of the FPA.[105] Some commenters argue that, for a generator to submit a 15-minute schedule, all balancing authorities involved in the transmission chain must approve the tag or it will be rejected.[106] While the source balancing authority may approve the schedule, PNW Parties explain that the schedule may be denied in the adjacent balancing area if the same intra-hour scheduling procedures are not used, irrespective of the jurisdictional status of the transmission providers involved. Xcel suggests that, in areas where the balancing authority and transmission provider are separate entities, explicit guidance may be needed in order for a balancing authority to accept intra-hour schedules from a transmission provider. Xcel

[105] *E.g.*, Avista; California ISO; Duke; EEI; Idaho Power; MidAmerican; NorthWestern; NV Energy; PNW Parties; Puget; Southern California Edison; Southern; Tres Amigas; WUTC.

[106] *E.g.*, PNW Parties; Puget; WUTC.

recommends that the Commission place responsibility on the balancing authority to approve intra-hour scheduling changes made in accordance with an approved tariff.

75. Additionally, these commenters question how beneficial intra-hour scheduling will be in the absence of consistent and compatible scheduling intervals among jurisdictional and non-jurisdictional entities.[107] Puget states that, while it has offered intra-hour scheduling since December 2009, its customers have scheduled few transactions due to the lack of conforming scheduling practices in neighboring non-jurisdictional utilities. If transmission customers are unable to schedule across seams at 15-minute intervals, Puget argues that jurisdictional utilities will receive little benefit from the required software, personnel and accounting changes needed to facilitate 15-minute scheduling. Idaho Power submits that seams issues created by different intervals in adjacent systems may ultimately lead to an increase in the costs of VER integration. WUTC asserts that for jurisdictional entities to implement intra-hour scheduling unilaterally would be economically unproductive and may disrupt reliability functions. Idaho Power and EEI similarly contend that seams issues may affect reliability.

76. EEI suggests that the Commission not require public utility transmission providers to provide intra-hour scheduling prior to an evaluation of the impacts on coordination between and among jurisdictional and non-jurisdictional entities. California ISO

[107] *E.g.*, Avista; California ISO; Duke; EEI; Idaho Power; NorthWestern; NV Energy; PNW Parties; Puget; Southern California Edison; Southern; Tres Amigas; WUTC.

contends the parties in the West should continue with coordinated efforts to find reasonable solutions that can be implemented without placing an undue burden on neighboring parties. California PUC recommends that the Commission allow sufficient flexibility for public utility transmission providers to determine the most efficient way to support intra-hour scheduling across interties.

77. Snohomish County PUD and Grays Harbor PUD request that the Commission evaluate whether existing supply arrangements with Bonneville Power, referred to as "slice" contracts, allow for intra-hour scheduling before adopting the proposed requirements. Snohomish County PUD explains that these contracts allow customers to pay a fixed percentage of Bonneville Power's costs and, in turn, receive an equal percentage of output, thereby taking advantage of the flexibility of the federal system. However, Snohomish County PUD and Grays Harbor PUD state that these "slice" contracts limit customers to hourly scheduling. Snohomish County PUD is concerned that it and other similarly situated transmission providers may be unable to implement 15-minute scheduling. Snohomish County PUD contends that, as a result, it and others may have to acquire additional reserves in order to balance wind resources, in effect paying twice for the same capacity and scheduling flexibility. Snohomish County PUD asserts that this issue has already arisen in Bonneville Power's ongoing efforts to develop intra-hour scheduling at 30-minute intervals.

iii. Cost to Implement Intra-Hour Scheduling

78. A number of parties address the potential costs of implementing the Commission's proposed intra-hour scheduling requirement. Exelon states that there likely will be some

development and ongoing administrative costs, such as modifying Open Access Same-Time Information System (OASIS) and interchange ramp software and additional staff to evaluate and confirm more frequent scheduling changes, but does not expect that such costs would be excessive. Tres Amigas contends that the incremental costs of providing intra-hour scheduling will be very modest. NaturEner argues that many transmission providers could implement intra-hour scheduling with existing staff and equipment but that, even if that is not the case, entities should be incentivized or required to automate or otherwise update their system as it would expedite the scheduling and transmission approval system. Independent Power Producers Coalition-West contends that increased automation and staffing would enhance the ability of a balancing authority to schedule at shorter intervals and achieve further integration of VERs.

79. Other commenters state that the cost of implementing intra-hour scheduling may be significant.[108] EEI and PNW Parties assert that intra-hour scheduling will affect many activities and systems, causing transmission providers in some regions to institute hardware, software, and personnel changes. For example, EEI and PNW Parties contend that changes will be required to numerous computer systems, such as energy management systems, scheduling applications, and automated checkout systems such as the WECC Interchange Tool, and also that certain practices not currently automated will have to be

[108] *E.g.*, Avista; Bonneville Power; EEI; Grant PUD; MidAmerican; NRECA; NorthWestern; PNW Parties; Puget; Snohomish PUD; Southern California Edison; Southwestern; Tacoma Power; TVA.

automated. EEI and PNW Parties note that staff would need to be trained on these new tools and additional staff would be required to process the expanded scheduling information being received. NRECA contends that the costs will be driven largely by software and personnel changes, rather than hardware investments, but that it is difficult to estimate with precision what software changes would be needed without knowing what measures NAESB will adopt in order to standardize the new scheduling regime.

80. NextEra explains that several steps will need to be taken in order to implement 15-minute scheduling but contends that the cost impacts are uncertain. NextEra provides that actions to implement intra-hour scheduling include potential modifications to both internal and external software packages. According to NextEra, these software programs, providing functions such as eTagging, accounting, and billing, will need to be harmonized across vendors. Additionally, NextEra contends that it is unclear whether existing systems would need to be replaced or modified, or whether functions currently being performed manually would need to be automated.

81. Some transmission providers estimate the level of investment and staffing changes that would be required to implement 15-minute scheduling on their system, although most discuss such estimates in the context of a broader range of activities that they believe may be intended or implicated by the implementation of 15-minute scheduling.[109] For example, Avista states that it would need to hire and train around-the-clock personnel

[109] *E.g.*, Avista; Bonneville Power; Grant PUD; MidAmerican; NorthWestern; PNW Parties; Puget; Snohomish County PUD; Southwestern; Tacoma Power; TVA.

at an estimated cost of $1.2 million per year to implement "an approach that will allow for schedule adjustments and imbalance settlements in 15 minute periods."[110] MidAmerican estimates approximately $1.0 million in staff costs to implement "similar intervals for balancing activities and interchange" and, to the extent energy management and accounting systems must be changed, up to $2.0-2.3 million in infrastructure upgrades.[111] Bonneville Power also contends that it would need an additional 24x7 position, staffed by six full-time employees, to manage what it characterizes as the risks created by 15-minute scheduling, including the redesign of imbalance service and increased use of special protection schemes.

82. NRECA notes that the relative cost impact of implementing intra-hour scheduling will depend on a number of factors, such as the size of the system and how widely intra-hour scheduling is utilized. Although agreeing that the costs may be significant, NRECA states that costs are not expected to be extraordinary and can be mitigated through proper design and implementation. NRECA estimates implementation costs under a range of scenarios. Assuming hourly schedules at a 15-minute interval used only by VERs, NRECA anticipates the need for software modifications in the range of $50,000 per company, but notes that some of its members have incurred expenses in the range of $250,000 annually for software licensing and maintenance related to scheduling and

[110] Avista at 12, 14 (emphasis in original).

[111] MidAmerican at 14.

energy accounting software upgrades. If hourly schedules at a 15-minute interval are widely used by transmission customers, NRECA estimates a minimum of one additional 24x7 shift, resulting in approximately $1.0 million of staffing costs, and potentially two 24x7 positions depending on the size of the transmission provider. Finally, if hourly schedules at a 15-minute interval are settled on a 15-minute basis, NRECA estimates an additional $250,000 to $300,000 for additional "back room" staff to settle 15-minute schedules, interchange and deviation accounts.

83. Bonneville Power contends that many of the short-term costs associated with 15-minute scheduling would not be incurred to implement scheduling on 30-minute intervals. Bonneville Power states that it is currently updating systems and work processes to implement 30-minute scheduling in association with regional initiatives and that it believes the changes, resources, and system impacts associated with the implementation of scheduling at a 30-minute interval will be relatively modest compared to what would be required to implement 15-minute scheduling. Bonneville Power asserts that the systems, transmission upgrades, and resources required to accommodate the increasingly dynamic movements of power across the interconnection under 15-minute scheduling would not be required under 30-minute scheduling. Tacoma Power argues that it will determine the level of automation needed for 30-minute scheduling based on the experience it gains during implementation of the Joint Initiative intra-hour program, but that implementation of 15-minute scheduling intervals as discussed in the Proposed Rule would require immediate automation of all the processes for Tacoma Power to have any market presence.

iv. Requests for Additional Requirements

84. Some commenters contend that transmission customers should be encouraged or required to submit intra-hour schedules, arguing that the Commission's objectives of lowering reserve costs can be reached only if intra-hour scheduling is utilized in a consistent and predictable manner.[112] Bonneville Power argues that mandatory intra-hour scheduling is necessary to achieve the reduction in reserve requirements of 80 percent cited in its 2008 study.[113] Idaho Power and PNW Parties contend that VERs generally have a strong financial incentive to maximize energy output and, therefore, may schedule for a full hour to maximize benefits regardless of the availability of 15-minute scheduling. WUTC recommends that the Commission couple the implementation of intra-hour scheduling with measures to mitigate over-scheduling by VERs, particularly when market conditions are favorable for over-scheduling.

85. Others recommend that the Commission provide incentives to use intra-hour scheduling by eliminating the exemption of VERs from third-tier generator imbalance penalties in Schedule 9 of the *pro forma* OATT, which they argue would no longer be

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[112] *E.g.*, Bonneville Power; EEI; Idaho Power; MidAmerican; NorthWestern; Puget; PNW Parties; WUTC.

[113] Bonneville Power (citing Bart McManus, *Large Wind Integration Challenges and Solutions for Operations/System Reliability* (2008). Bonneville Power clarifies that, in the study, mandatory 10-minute scheduling on a 10-minute persistence basis reduced the reserve requirements in the BPA region by 80 percent. Bonneville Power also clarifies that this reduction only applies to the source Balancing Authority, not the sink Balancing Authority).

just and reasonable given the Commission's proposed reforms.[114] In addition to eliminating the exemption from third-tier generation imbalance penalties, MidAmerican suggests that an additional imbalance penalty tier be created for any transmission customer that consistently fails to adjust schedules on an intra-hour basis and creates significant variability. Avista recommends that the Commission allow transmission providers to impose appropriate penalties and recover the true costs of providing intra-hour schedules from VERs that continue to schedule on an hourly basis.

86. Several commenters argue that intra-hour scheduling may not achieve its intended benefits without additional reforms to augment intra-hour scheduling practices.[115] Some of these commenters assert that the Commission should allow a public utility transmission provider the flexibility to revise its energy imbalance settlement periods to align with any intra-hour scheduling interval.[116] Southern contends that this will allow a public utility transmission provider to offer appropriate incentives to customers to follow a given schedule and limit the potential for exposure to uncompensated risks.

87. However, Avista states that there are positives and negatives to either maintaining hourly settlement with intra-hour scheduling or modifying settlement intervals to coincide with intra-hour scheduling intervals. Avista asserts that conforming intra-hour

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[114] *E.g.*, Avista; EEI; Idaho Power; MidAmerican; Puget; WUTC.

[115] *E.g.*, Avista; AWEA; RenewElec; Vote Solar.

[116] *E.g.*, EEI; Duke; Idaho Power; Southern.

schedules and imbalance settlement at 15-minute increments for all transmission schedules would result in alignment of scheduling and imbalance billing for all transactions and reduce gaming potential. Avista argues that the potential for gaming by transmission customers through the overcorrection of schedules in order to minimize imbalance charges may require a public utility transmission provider to carry regulation reserves in excess of what is needed. Midwest ISO agrees, citing a report from its Independent Market Monitor indicating that large changes in Net Scheduled Interchange caused by 15-minute intra-hour scheduling could lead to price volatility and negative operational impacts.[117] Avista and Midwest ISO further state that conforming imbalance settlement with intra-hour schedules may require substantial and potentially costly office system changes, additional operations staff, and other costs incurred through the communication, metering, and storage of all customer data at 15-minute increments.

88. Some commenters contend that intra-hour scheduling only governs the scheduling of flows on the transmission system and, by itself, does not necessarily affect the frequency with which generators are dispatched.[118] AWEA and Invenergy Wind agree that a transition to sub-hourly dispatch is the key for increasing the flexibility of the power system and for reducing the amount of reserves that must be held, which in turn will reduce costs for consumers and enable cost effective integration of VERs.

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[117] Midwest ISO (Potomac Economics, 2008 *State of the Market Report for the Midwest ISO*, Docket No. ZZ09-4-000 at 169 [141] (June 21, 2009)).

[118] *E.g.*, AWEA; CEERT; Invenergy Wind.

Commenters recommend that the Commission require public utility transmission providers to implement a sub-hourly, real-time energy exchange that provides automated generation dispatch (such as an Efficient Dispatch Toolkit or the Energy Imbalance Market as adopted by the Southwest Power Pool and currently being studied in WECC). In AWEA's view, a market for sub-hourly energy would allow for netting of sub-hourly deviations and would provide price signals to incent greater sub-hourly flexibility.

89. AWEA acknowledges that changes to dispatch protocols and expansion of market options are being considered in regional efforts, but argues that progress is uncertain and unlikely to come to fruition in the near term. Iberdrola argues that intra-hour scheduling must be combined with intra-hour dispatch or market purchases to achieve the Commission's goals. Oregon and New Mexico PUC recommend that the Commission encourage reforms such as an Energy Imbalance Market or 15-minute calculations of available transmission capability (ATC) as a complement to intra-hour scheduling. However, Bonneville Power suggests distinguishing between intra-hour scheduling outside of a market region and intra-hour dispatch in an organized market, arguing that the costs and benefits of each may be dramatically different. Bonneville Power explains that the resources devoted to implementing 15-minute scheduling may be better used to pursue the development of an organized market with frequent dispatch intervals.

90. Some commenters assert that the Commission should consider changes to other aspects of electricity markets to facilitate intra-hour scheduling.[119] Invenergy Wind contends that consistent timeframes across all transmission and generation functions may lead to more efficient use of transmission capacity, regulation, and other ancillary services. American Clean Skies explains that the technology necessary to schedule transmission in 15-minute increments will also allow for scheduling reforms in the day-ahead market and the unit commitment process and, therefore, the Commission should require 15-minute scheduling reforms in these areas as well. However, PJM asserts that real-time control issues do not exist day-ahead and, therefore, the Commission need not consider reforms to the day-ahead market.

c. Commission Determination

91. The Commission concludes that it is appropriate to act at this time to adopt the scheduling reforms set forth in the Proposed Rule. Specifically, the Commission amends the *pro forma* OATT to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals. Our actions in this Final Rule will ensure that charges for generator imbalance service under Schedule 9 of the *pro forma* OATT and for other ancillary services through

[119] *E.g.*, American Clean Skies; Invenergy Wind.

which reserve-related costs are recovered are just and reasonable and are not unduly discriminatory.[120]

92. As noted in the Proposed Rule, many *pro forma* OATT requirements, including hourly scheduling protocols, were developed at a time when virtually all generation on the system could be scheduled with relative precision.[121] As part of the Commission's regulatory responsibilities, we routinely review and, where appropriate, implement reforms to ensure the provision of service that remains just and reasonable and not unduly discriminatory. A similar review led the Commission in Order No. 890 to exempt VERs from the third-tier of generator imbalance penalties, given that VERs have a limited ability to accurately follow an hourly transmission schedule and, as a result, exposure to high imbalance penalties does not lessen their incentive to deviate from their schedule.[122] In this Final Rule, we take an additional step to allow transmission customers the flexibility to adjust their transmission schedules, in advance of real-time, to reflect the variability of output in generation, more accurate power production forecasts to predict output, and other changes in load profiles and system conditions.

[120] In section IV.C (Generator Regulation Service Capacity) *infra*, the Commission acknowledges that a range of capacity services could be used by public utility transmission providers to recover reserve-related costs.

[121] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 38.

[122] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 665.

93. Specifically, the Commission affirms the preliminary finding in the Proposed Rule that existing hourly scheduling protocols expose transmission customers to excessive or unduly discriminatory generator imbalance charges.[123] Under Schedule 9 of the *pro forma* OATT, generator imbalance charges are assessed on deviations between generator output and a delivery schedule over a single hour.[124] There is no requirement to provide customers the opportunity to adjust their transmission schedules within the hour to reflect changes in generator output. As a result, transmission customers have no ability under the *pro forma* OATT to mitigate Schedule 9 generator imbalance charges in situations when the transmission customer knows or believes that generation output will change within the hour. The Commission concludes that this lack of ability to update transmission schedules within the hour can cause charges for Schedule 9 generator imbalance service to be unjust and unreasonable or unduly discriminatory. As a result of the intra-hour scheduling reforms of this Final Rule, the metric against which generator imbalances are measured will be more granular than under current hourly scheduling protocols.

[123] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 37.

[124] Imbalance charges are calculated by multiplying the quantity of imbalance by a set percentage of incremental or decremental costs defined in three deviation bands. These charges are netted on a monthy basis and settled financially at the end of each month. For example, any deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction (applied hourly) will be settled at 125 percent of incremental costs or 75 percent of decremental costs. *See* OATT Schedule 9.

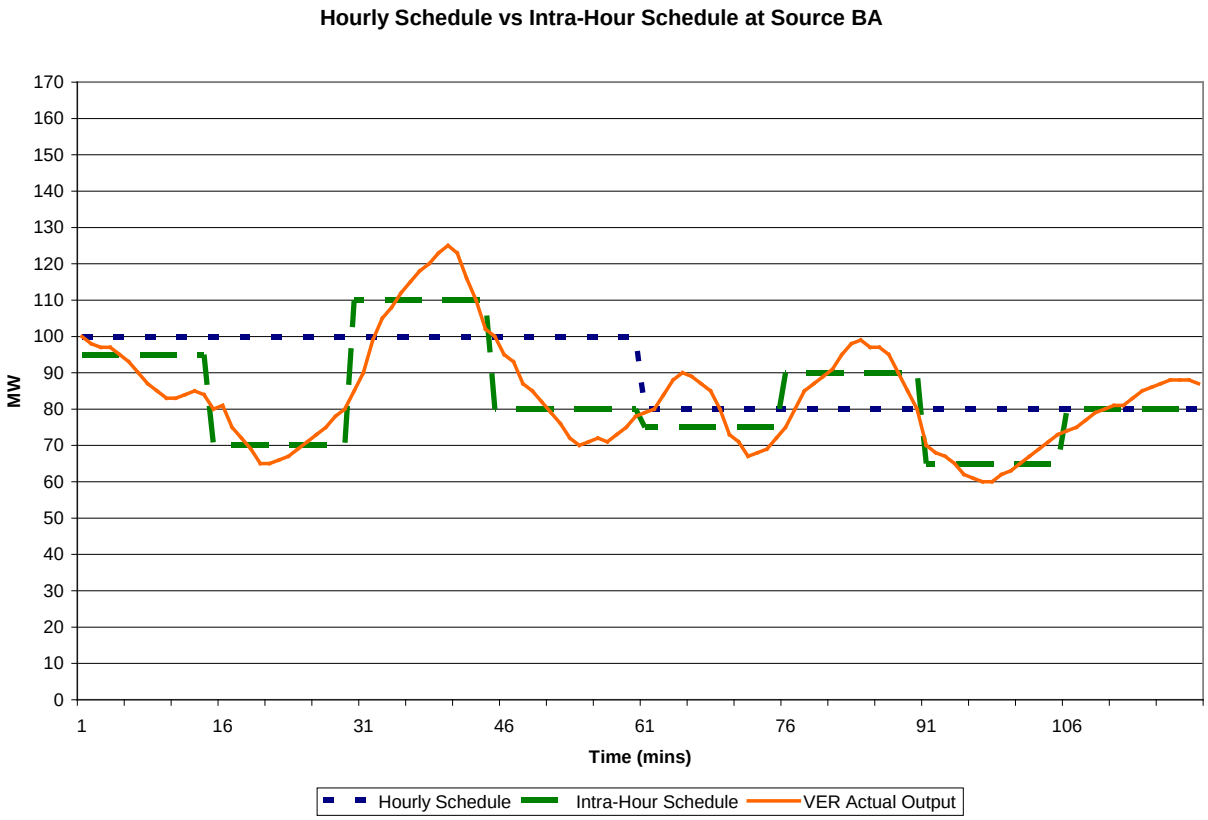
94. The Commission expects that many types of entities, not only VERs, may benefit from the availability of intra-hour scheduling. Every transmission customer will have the ability to adjust its schedule at 15-minute intervals to reflect changing conditions. This includes, for example, transmission customers that experience a within-hour forcedoutage or transmission customers taking delivery from energy constrained resources (such as flow-limited hydro-electric generators, emission-limited thermal generators, and energy storage resources), even if using point-to-point transmission internal to the system. For example, we note that Entergy voluntarily adopted intra-hour transmission scheduling without the presence of substantial VERs in an effort to manage fluctuations in output from qualifying facilities on its system.[125] Based on this experience and the record in this proceeding, the Commission finds that intra-hour scheduling will provide a range of transmission customers with a necessary tool to mitigate exposure to Schedule 9 generator imbalance charges in light of changing conditions.

95. The Commission also finds that, over time, implementation of intra-hour scheduling will allow public utility transmission providers to rely more on planned scheduling and dispatch procedures, and less on reserves, to maintain overall system balance. Under hourly scheduling protocols, the source balancing authority for a transaction is required to honor its transmission schedule across an entire hour, requiring the source balancing authority to have sufficient reserves in place to manage imbalances

[125] *See Entergy Serv. Inc.*, 111 FERC ¶ 61,314 (2005).

within the hour, i.e., maintain consistent delivery of the scheduled amount of energy to the sink balancing authority over the hour. This includes reserves to respond to variations in generation output that are moment-to-moment as well as longer-term, but occurring within the hour, represented by the solid line in Figure 1.

Figure 1



96. By moving from hourly to 15-minute scheduling intervals, the amount of imbalance energy for which the source balancing authority is potentially responsible can be reduced, as reflected in Figure 1. This can lead to a corresponding reduction in the amount of capacity held to provide that energy and, in turn, lower reserve-related costs for the source balancing authority, and ultimately consumers. Therefore, the Commission

also finds that implementation of intra-hour schedules is necessary in order to ensure that charges for ancillary services through which reserve-related costs are recovered are just and reasonable and not unduly discriminatory.[126]

97. For these reasons, the Commission adopts the proposal set forth in the Proposed Rule and directs public utility transmission providers, consistent with the compliance deadlines addressed below, to revise their OATTs to provide an opportunity for transmission customers to submit transmission schedules at 15-minute intervals. In response to Bonneville Power and Xcel, the Commission clarifies that this requirement is intended to allow transmission customers to both modify existing schedules as well as create new schedules, provided that the transmission customer has a transmission reservation in place.[127] The ability to create new transmission schedules within the hour will be particularly important to resources that may seek to provide intra-hour energy products, as discussed further below.

[126] One mechanism that could be used to recover reserve-related costs is generator regulation service. The Commission provides guidance regarding the development of generation regulation charges in section IV.C.2 (Mechanics of Generator Regulation Charge) *infra*. Among other things, public utility transmission providers should consider the extent to which transmission customers are using intra-hour scheduling in evaluating whether to require different transmission customers to provide or otherwise account for different quantities of generator regulation service.

[127] To be clear, this Final Rule does not alter the transmission products of the *pro forma* OATT and, therefore, implementation of intra-hour scheduling does not require (yet would not preclude) the intra-hour calculation of ATC or sale of transmission service.

98. The Commission notes that most commenters support the practice of intra-hour scheduling, with disagreement focused primarily on the frequency of schedule adjustments and whether changes to existing scheduling should be paired with other reforms. Balancing the competing considerations raised by commenters, the Commission concludes that a 15-minute scheduling interval is appropriate and declines to impose additional reforms at this time. The Commission appreciates that implementation of other reforms, such as intra-hour imbalance settlement, an intra-hour transmission product, increasing the frequency of resource commitment through sub-hourly dispatch, or the formation of intra-hour imbalance markets, could yield additional benefits for public utility transmission providers and their customers. However, these additional reforms can have significant costs. The Commission's review of the record in this proceeding suggests that a more measured approach is appropriate to take at this time.[128]

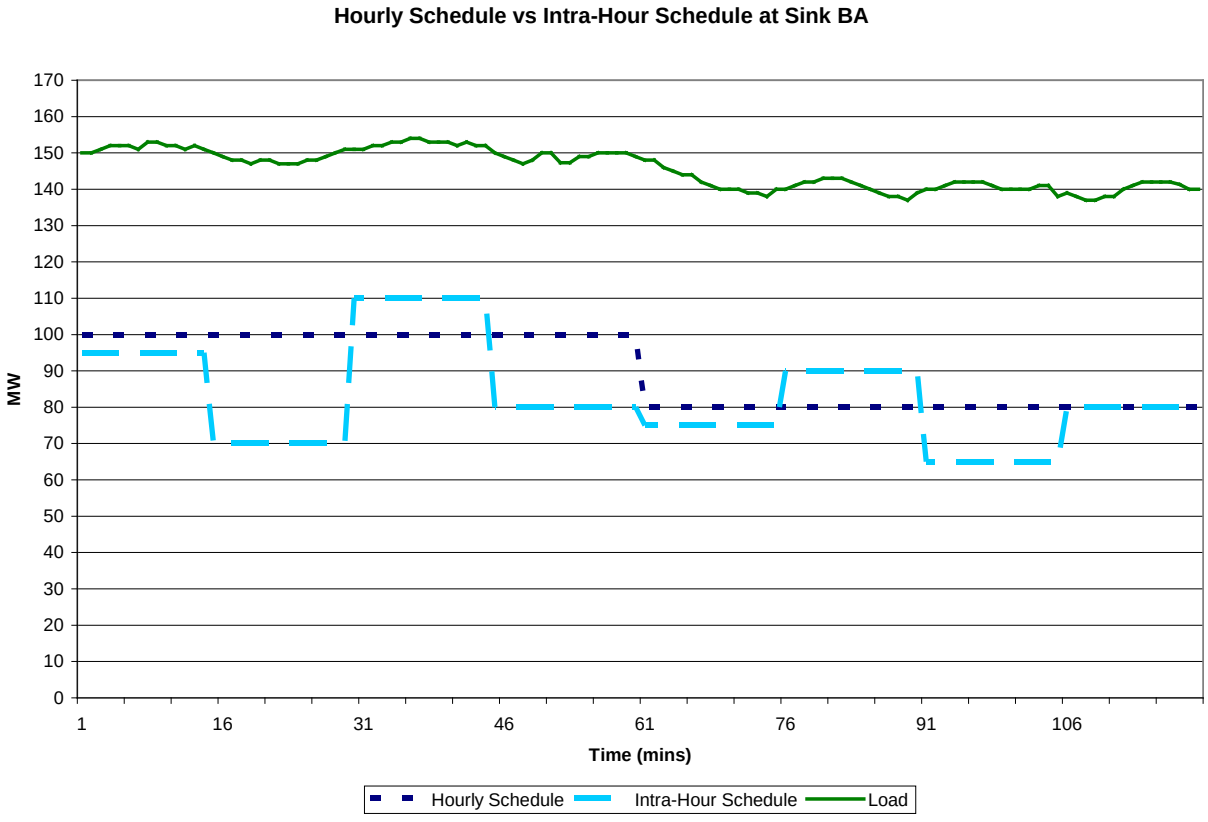
99. The Commission acknowledges that implementation of intra-hour scheduling can result in a shift of responsibility for holding certain reserves away from the source balancing authority for export transactions.[129] As explained above, allowing for more granular transmission schedules can reduce the amount of variation in generation output

[128] As noted below, public utility transmission providers will have an opportunity on compliance to demonstrate that alternative intra-hour scheduling proposals are consistent with or superior to the intra-hour scheduling requirements of this Final Rule. Such a proposal could include one or more of the additional reforms requested by commenters, such as the formation of intra-hour imbalance markets.

[129] *E.g.*, Xcel; Iberdrola.

for which the source balancing authority is responsible. The Commission appreciates that, from the sink balancing authority's perspective, scheduling at shorter intervals may result in the purchaser of energy having to manage more frequent changes in scheduled deliveries as compared to scheduling at hourly intervals. As indicated in Figure 2, a purchaser under existing hourly scheduling protocols receives a fixed quantity of energy over the hour from the source balancing authority, whereas use of 15-minute intervals could result in fluctuating deliveries across the hour.

Figure 2



To the extent the purchaser desires to continue receiving a constant delivery of energy across the hour, represented by the dotted line in Figure 2, it may be required to obtain

that energy from the market.[130] The Commission concludes that this is an appropriate division of responsibility, as opposed to the current hourly system which places all responsibility for managing variations in generation output across the hour solely on the source balancing authority. Within the hour, the source balancing authority retains its responsibility of providing the energy needed for the VER to meet its schedule, while the purchaser takes on the responsibility of managing more frequent deliveries of scheduled energy.

100. By shifting responsibility for managing certain variations in generation output to the purchasing entity, purchasing entities will have greater incentive to manage changes in scheduled deliveries from 15-minute interval to 15-minute interval and the portfolio of resources that ultimately manage total VER variability will likely be more cost-effective than under current practices. Specifically, a portfolio of resources that respond over a range of time scales, from very fast to relatively slow, is lower cost than a portfolio that relies on resources designed to manage only the short-run variability of VERs.[131] For instance, portfolio cost savings could result from using a combination of expensive resources with automated generator control and less expensive resources that provide following serice rather than using only resources with automated generator control.

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[130] For example, sellers of VER energy could have existing contractual commitments to deliver at constant volumes over specified periods.

[131] *See e.g.*, J. Apt, *The Spectrum of Power from Wind Turbines.* Journal of Power Sources, Vol. 169, No. 2, at 369-374 (2007); cited at RenewElec comments at note 4.

While the source balancing area could choose to manage VER variability with a portfolio of resources that respond over a range of time, it has little incentive to do so because any additional costs can be recovered from transmission customers. We expect use of a portfolio of resources to lower the overall cost of managing VER variability. The Commission anticipates that buyers and sellers also may respond by developing intra-hour balancing products. EPSA notes that the additional market liquidity created by the ability to schedule transmission intra-hourly can provide opportunities for existing resources to manage system variability by offering within-hour energy products. This is equally true for market participants seeking to maximize the value of their resources, or lower their purchased power costs, through intra-hour trading. As the liquidity of intra-hour energy products stabilizes, market participants also may begin to commit or otherwise acquire fewer reserves in advance, with the knowledge that they can purchase additional reserves on an as-needed basis from third parties. Requiring public utility transmission providers to offer intra-hour scheduling is a necessary predicate to facilitate these market opportunities.[132]

101. Notwithstanding broad support in comments for some version of intra-hour scheduling, as noted above, there was significant disagreement in the comments as to the appropriate time interval. Some commenters supported the 15-minute interval proposed

[132] For example, the Joint Initiative has implemented an electronic platform to facilitate bilateral intra-hour transactions, the Intra-hour Transaction Accelerator Platform (I-TAP), also referred to as the WebExchange. *See* http://www.columbiagrid.org/itap-overview.cfm.

by the Commission,[133] while others argued for either shorter (e.g., 5-minute) or longer (e.g., 30-minute) scheduling intervals.[134] In evaluating these comments, the Commission has balanced the competing interests of allowing transmission customers to more closely match schedules with anticipated generation output against not unduly burdening public utility transmission providers in implementing the intra-hour scheduling reform. The Commission concludes that adoption of a 15-minute scheduling interval for purposes of the *pro forma* OATT is reasonable. In its comments on the NOI, NERC states that the ideal scheduling increment would be between 5 and 15 minutes depending on system characteristics.[135] NERC reasoned that, while balancing authorities that schedule energy transactions on an hourly basis may have sufficient regulation resources to maintain the schedule for the hour, reducing scheduling intervals to ten minutes, for example, could make economically dispatchable generators in an adjacent balancing authority available

[133] *E.g.*, A123; Alstom Grid; ACSF; Argonne National Lab; BP Companies; CESA; CEERT; Center for Rural Affairs; Clean Line; CGC; Defenders of Wildlife; EPSA; Exelon; First Wind; Independent Energy Producers; NaturEner; Organization of Midwest ISO States; Oregon & New Mexico PUC; Powerex; Public Interest Organizations; SWEA; Tres Amigas; Viridity Energy; Western Grid; Xcel.

[134] *Compare* Environmental Defense Fund; FriiPower; Independent Power Producers Coalition-West; RenewElec; SEIA; Vestas; and Vote Solar (advocates of shorter) *with* Bonneville Power; California PUC; CMUA; Montana PSC; NorthWestern; Puget; Snohomish County PUD; Southern California Edison; WUTC(advocates of longer).

[135] NERC April 12, 2010 Response to NOI (NERC NOI Comments).

to provide necessary ramping capability through an interconnection.[136] The Commission agrees and, as discussed above, anticipates that the availability of intra-hour scheduling at 15-minute intervals will facilitate the development of ramping products to manage variability in generation output more effectively. For these reasons we adopt 15-minute transmission scheduling as proposed.

102. In adopting a 15-minute transmission scheduling interval, we recognize that the cost of moving from hourly to 15-minute transmission scheduling could be substantial. Several transmission providers state that costs will depend heavily on the extent to which intra-hour scheduling is actually used by transmission customers, estimating staffing costs to be in the range of $1-2 million per year if widely used.[137] While these costs are not insignificant, greater use of intra-hour schedules means that more transmission customers are mitigating exposure to Schedule 9 generator imbalance charges and providing greater opportunities for public utility transmission providers to lower reserve-related costs. Commenters generally agree that the cost of implementing intra-hour scheduling will correlate to usage, with lower costs in those systems with fewer intra-hour schedules. In contrast, substantial use of intra-hour scheduling would affirm the

[136] NERC NOI Comments.

[137] *E.g.*, Avista; NRECA. To the extent intra-hour scheduling is not widely used by transmission customers, NRECA states its members likely could implement scheduling at 15-minute intervals with software modifications in the range of $50,000 per company, without additional staffing requirements.

usefulness of the option for transmission customers, justifying the added expense of processing a larger number of transmission schedules.

103. Many of the costs cited by commenters as being specific to 15-minute scheduling are related to the automation of systems used to process transmission schedules and verify cross-balancing authority aggregate schedules. The Commission notes that it is not mandating automation of scheduling practices, although we expect that each public utility transmission provider will consider whether automation of certain aspects of its system are necessary to implement scheduling at 15-minute intervals. To the extent a public utility transmission provider automates scheduling processes in response to increased scheduling activity, the Commission agrees with NaturEner and Independent Power Producers Coalition-West that automation of these processes represents a secondary benefit of our transmission scheduling reform. Several Commission staff audits have uncovered errors related to manual processing of transmission schedules.[138] These errors resulted in a transmission customer submitting a transmission schedule that resulted in a higher curtailment priority than the underlying transmission service reservation provided, allowed use of firm network service to deliver energy from resources that were not designated resources and allowed use of network transmission service to deliver a sale to a third party. As a result of these errors, the transmission

[138] *E.g.*, *Puget Sound Energy*, Docket No. PA07-1-000 at 25-27; *MidAmerican Energy Co.*, Audit Report, 112 FERC ¶ 61,346 at PP 30-34 (2005); and *Public Service Company of Colorado*, Docket No. PA05-1-000 at 9-11.

customer may have gained access to transmission service that was not otherwise available, may have inappropriately gained additional protection from curtailment, and avoided payment for point-to-point transmission service. Increased automation of schedule process can reduce such errors and, in turn, ensure that the provision of transmission service is consistent with the *pro forma* OATT.

104. Some commenters raising concerns regarding the cost of implementing intra-hour scheduling imply that the proposed scheduling reforms would require changes in settlement procedures for imbalance service or the frequency of resource commitment through sub-hourly dispatch, which they state would require significant investments. For example, EEI and PNW Parties caution that these additional activities would affect computer systems, such as energy management and accounting systems.[139] MidAmerican estimates that upgrading such systems would cost $2.0-2.3 million. Other commenters, however, encourage the Commission to require intra-hour imbalance settlement and sub-hourly dispatch in order to align intra-hour scheduling with financial settlements and resource commitment. The Commission clarifies that the requirements of this Final Rule apply to scheduling practices, not imbalance settlement or sub-hourly dispatch. Public utility transmission providers may continue to calculate *pro forma*

[139] *Eg.*, EEI; PNW Parties.

Schedule 9 generator imbalance charges on an hourly basis under the *pro forma* OATT and rely on hourly resource commitment practices.[140]

105. Notwithstanding the continued ability of public utility transmission providers to rely on hourly calculation of Schedule 9 generator imbalances, as a result of the intra-hour scheduling reforms of this Final Rule, the metric against which generator imbalances are measured will be more granular than under current hourly scheduling protocols. To the extent a public utility transmission provider believes that aligning the imbalance settlement with the intra-hour scheduling interval or implementing sub-hourly dispatch will result in more efficient operations, provide appropriate price signals to customers, or address other potential issues, it may seek any authorizations necessary from the Commission to do so under section 205 of the FPA.[141] Such proposals could be submitted contemporaneously with the compliance filing in response to this Final Rule or at such other time the public utility transmission provider believes appropriate.

106. Several commenters request that the Commission allow for regional variation in scheduling protocols.[142] In the Western Interconnection, many public utility transmission

[140] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 722; Order No. 890-A, FERC Stats. & Regs. ¶ 61,297 at P 325 & n.117.

[141] For example, PNW Parties and Idaho Power note that the financial incentives some transmission customers have to maximize output over an hour may in some instances counteract financial incentives to adjust transmission schedules on a 15-minute basis.

[142] *E.g.*, Avista; Bonneville Power; California ISO; CESA; CMUA; California PUC; Detroit Edison; EEI; FirstEnergy; Grant PUD; Idaho Power; Independent Power

(continued…)

providers already have implemented some form of intra-hour scheduling at 30-minute intervals as part of an effort to enhance the operation of bilateral markets in the Western Interconnection.[143] Other tools recently implemented in the West include the I-TAP electronic platform to schedule energy and request transmission, the Dynamic Scheduling System to facilitate dynamic scheduling,[144] and the ACE Diversity Interchange Program to allow netting of momentary imbalances across participating balancing authority footprints.[145] Public utility transmission providers, state regulators, and others in the West are studying the impact of these recent initiatives, as well as the potential benefits and costs of pursuing additional market enhancements in the future, such as formation of an energy imbalance market. The Commission acknowledges that future market enhancements in addition to existing 30-minute scheduling practices and the above-referenced tools, might yield equivalent or greater benefits to transmission customers and public utility transmission providers when compared to reducing the scheduling interval

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Producers Coalition-West; ISO/RTO Council; Midwest ISO; National Grid; Northwestern; NRECA; New York ISO; NV Energy; Pacific Gas & Electric; PJM; PNW Parties; Public Power Council; Puget; SMUD; Tacoma Power; WUTC; and WestConnect.

[143] *See e.g.*, *Arizona Public Service Co.*, 137 FERC ¶ 61,023 (2011), *NorthWestern Corp.*, 136 FERC ¶ 61,119 (2011).

[144] *See* Joint Initiative.

[145] *See* NERC, *DRAFT Reliability Guideline: ACE Diversity Interchange* (June 2012), *available at* http://www.nerc.com/docs/oc/rs/Draft%20ADI%20Reliability%20Guideline%20-%20V1%20060112.pdf.

from 30 to 15 minutes and therefore could be consistent with or superior to the Final Rule's intra-hour scheduling requirements.

107. The Commission therefore affirms the ability of public utility transmission providers to submit alternative proposals that are consistent with or superior to the intra-hour scheduling requirements of this Final Rule and are otherwise just and reasonable and not unduly discriminatory or preferential.[146] To make such a showing, a public utility transmission provider must demonstrate in its compliance filing how its proposal provides equivalent or greater opportunities for transmission customers to mitigate Schedule 9 generator imbalance charges, and for the public utility transmission provider to lower its reserve-related costs, when compared to implementation of the intra-hour scheduling requirements of this Final Rule under market practices currently in place within the region, including tools referenced above that already have been implemented in the West.[147] The public utility transmission provider must include in its compliance filing the tariff provisions necessary to implement its proposal, including the interval at which transmission customers may submit transmission schedules. The public utility

[146] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,770.(permitting public utility transmission providers to propose tariff modifications that are consistent with or superior to the requirements of the *pro forma* OATT).

[147] To the extent such an alternative proposal includes a commitment to develop and implement additional market enhancements in the future, the public utility transmission provider must provide in its compliance filing: a commitment by senior management to develop and implement the proposal; a description of collaborative efforts to date and timeline for future efforts in support of developing the proposal; and, the date by which the proposed market enhancement will be implemented.

transmission provider also must address how its proposed scheduling interval is consistent with other scheduling practices within its region. Finally, in recognition that implementation of intra-hour scheduling can result in a shift of responsibility for holding certain reserves away from the source balancing authority for export transactions, public utility transmission providers may consider the extent to which alternative proposals result in savings to transmission customers across multiple public utility transmission provider systems when making the demonstration required above.

108. Turning to other issues raised by commenters, the Commission is not convinced by arguments that the current exemption from third-tier generator imbalance penalties for intermittent resources should be eliminated to create an incentive for VERs to take advantage of the option to update transmission schedules every 15 minutes.[148] In Order No. 890, the Commission found intermittent generators cannot always accurately follow their schedules and that high penalties will not lessen the incentive to deviate from their schedules.[149] While the implementation of 15-minute scheduling provides an opportunity for VERs to better align transmission schedules with actual generation, the Commission continues to believe that third-tier generator imbalance penalties are unduly punitive for VERs given their relative inability to accurately follow schedules whether submitted on an hourly or 15-minute interval. The Commission concludes that the ability to avoid

[148] *E.g.*, Avista; EEI; Idaho Power; MidAmerican; Puget; WUTC.

[149] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 665.

penalties in the first two tiers of generator imbalance charges will provide a sufficient incentive for VERs to adjust transmission schedules, to the extent they believe such adjustments will mitigate exposure to Schedule 9 generator imbalance charges. If a public utility transmission provider believes it necessary to address intentional deviations, it may propose revisions to Schedule 9 generator imbalance service pursuant to section 205 of the FPA.[150] Such proposals would need to demonstrate that VERs are not adjusting their transmission schedules despite their reasonable ability to foresee that output will deviate significantly from existing transmission schedules.[151]

109. The Commission acknowledges comments made by some, particularly in the Pacific Northwest, asserting that the benefits of intra-hour scheduling will not be fully realized if non-jurisdictional entities do not adopt a consistent scheduling interval.[152] However, the Commission does not believe that limitations in our ratemaking jurisdiction

[150] *Cf. id.* P 676 (noting the ability of public utility transmission providers to propose additional imbalance penalties for intentional deviations). Alternatively, the public utility transmission provider may propose alternative designs for other ancillary services rates to, for example, offer lower rates to those transmission customers committing to use intra-hour scheduling.

[151] The Commission notes that there is a relationship between a public utility transmission provider's potential need for alternative imbalance charge structures and the period used for imbalance settlements. Reinstating third-tier imbalance penalties in combination with shortened imbalance settlements would more likely punish VERs for variability that they cannot control, contrary to the exemption granted in Order No. 890 and affirmed here.

[152] *E.g.*, Avista; California ISO; Duke; Idaho Power; NorthWestern; NV Energy; PNW Parties; Puget; Southern California Edison; Southern; Tres Amigas.

over non-public utilities should stop us from moving ahead with reforms applicable to public utilities simply because the impact of those reforms might be more significant with participation by all entities. As explained above, requiring all public utility transmission providers to offer 15-minute transmission scheduling will enable public utility transmission providers and their customers to manage system variability more effectively. Therefore, the Commission is hopeful that non-jurisdictional transmission providers will voluntarily choose to implement 15-minute transmission scheduling in order to better manage variations in generation output. We understand that the existence of compatible business practices within a region is beneficial, and we encourage both jurisdictional and non-jurisdictional transmission providers to continue to coordinate and collaborate in order to maintain the continuity of the system and address issues as they arise. This includes collaboration in the development of any alternative compliance proposals developed by public utility transmission providers.

110. The Commission disagrees with comments by Southern and others that different scheduling intervals between jurisdictional and non-jurisdictional transmission providers may negatively affect reliability within an interconnection.[153] In the event a non-jurisdictional transmission provider only accepts hourly schedules, any attempt to submit an intra-hour schedule for delivery to the non-jurisdictional transmission provider would

[153] *E.g.*, EEI; Idaho Power; NorthWestern; Southern; Tacoma Power.

be rejected, as several commenters note.[154] This may lead to an inability to implement 15-minute scheduling fully and, in turn, could result in less effective management of system variability. However, the Commission does not believe that it would create any reliability challenges beyond those that exist today under hourly scheduling protocols. The Commission notes that voluntary efforts to implement intra-hour scheduling on 30-minute intervals in the Western Interconnection referenced above have not been uniformly applied, yet do not appear to have negatively affected reliability.

111. In response to concerns raised by Snohomish County PUD and Grays Harbor PUD regarding "slice" contracts with Bonneville Power, the Commission acknowledges that some existing power supply arrangements may not be flexible enough to take advantage of the benefits of intra-hour scheduling. Over time, the Commission anticipates that the market will respond to the availability of intra-hour scheduling through the development of new balancing products as well as modifications of existing arrangements where appropriate. However, in the case where the terms of an existing contract are inconsistent with intra-hour scheduling and cannot be modified, the Commission appreciates that the benefits of intra-hour scheduling may not be available with respect to that particular transaction.

112. In response to comments by WestConnect and NorthWestern that a 15-minute scheduling interval is inconsistent with the standard 20-minute generator ramp rate used

[154] *E.g.*, PNW Parties; Puget; WUTC.

in the West, we note that many of the Joint Initiative transmission providers – including members from WestConnect – have already implemented a 10-minute ramp rate to accommodate 30-minute transmission schedules. To the extent changes in ramping are necessary to support use of a 15-minute transmission schedules, it does not appear that such changes present a significant impediment for public utility transmission providers.

113. A number of commenters question the applicability of the intra-hour scheduling requirements to public utility transmission providers in RTO and ISO regions.[155] The Commission clarifies that the implementation of 15-minute transmission scheduling will only apply to intertie transactions in organized wholesale energy markets. The Commission finds that a consistent scheduling interval for transactions among all public utility transmission providers, including RTOs, is necessary in order to attain the benefits of intra-hour scheduling noted above. Additional reforms to other markets requested by commenters, such as adjustments to day-ahead markets, are beyond the scope of this rulemaking.

2. Implementation of Intra-Hour Scheduling

114. Commenters raise a number of additional issues related to how the intra-hour scheduling requirements adopted in this Final Rule should be implemented. The Commission addresses these issues below, including the following: (1) the appropriate notification period for submitting transmission schedules; (2) the recovery of costs

[155] *E.g.*, AWEA; Iberdrola; ISO New England; Massachusetts DPU; PJM; Public Interest Organizations; RENEW; Sunflower and Mid-Kansas; Western Farmers.

associated with implementing intra-hour scheduling; (3) clarifications regarding the definition of transmission schedule, curtailment priorities, and calculations of ATC; (4) review of NERC reliability standards and NAESB business practices; and (5) other issues related to high voltage direct current (HVDC) transmission lines, dynamic scheduling, and the geographic location of resources used to provide reserves.

a. Notification Time for Submission of Transmission Schedule

i. Commission Proposal

115. In the Proposed Rule, the Commission proposed to allow all transmission customers the option of submitting intra-hour schedules up to 15 minutes before each scheduling interval.[156]

ii. Comments

116. Several commenters ask the Commission to retain the existing 20-minute notification time for submission of transmission schedules, arguing that schedules should be submitted no later than 20 minutes prior to the start of the schedule as required by NERC Reliability Standards INT-005, INT-006, INT-008, and NAESB WEQ-004 Appendix D.[157] Commenters contend that allowing only 15 minutes between schedule submission and start would not provide enough time for transmission operators to adequately evaluate, approve, and implement transmission schedules. ISO/RTO Council

[156] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 41.

[157] *E.g.*, Duke; EEI; Entergy; NRECA; PJM; Puget; Southern.

adds that changing to a 15 minute notice period will require transmission operators to change their current systems and increase staff levels for processing transmission schedule requests. PJM comments that the 20-minute notification deadline is an established industry standard and that it should not be changed to 15 minutes.

117. Although not opposed to the Commission's proposal, NaturEner states that a shorter notification period would result in abbreviated response times for everyone in the scheduling process, including transmission customers. NaturEner asks the Commission to clarify that transmission providers have the discretion to accept schedule changes after the notification deadline. NaturEner contends that inclusion of such a clarification both supports the reform's underlying rationales and avoids any unnecessary future confusion regarding whether a balancing authority or transmission provider possesses such discretion.

iii. Commission Determination

118. The Commission will retain the existing 20-minute prior notification period for the submission of a transmission schedule and not adopt its proposal. The Commission agrees with commenters that the existing 20-minute prior notification period is needed to adequately evaluate, approve and implement transmission schedules. Accordingly, the Commission retains the existing notification period set forth in sections 13.8 and 14.6 of the *pro forma* OATT, which permits scheduling changes up to 20 minutes (or a reasonable time that is generally accepted in the region and is consistent and adhered to by the transmission provider) before the start of the next schedule change provided that the delivering party and receiving party also agree to the schedule modification. In

response to NaturEner, the existing language of the *pro forma* OATT provides adequate flexibility for transmission providers to adopt alternative deadlines for accepting scheduling changes.

b. Recovery of Intra-Hour Scheduling Costs

i. Commission Proposal

119. In the Proposed Rule, the Commission proposed to allow public utility transmission providers to recover any costs incurred to implement the proposed intra-hour scheduling reform pursuant to Schedule 1 of a transmission provider's OATT.[158]

ii. Comments

120. Several commenters support the Commission's proposal, arguing that the benefits of intra-hour scheduling apply to more than VERs and, thus, costs relating to the implementation of intra-hour scheduling should be allocated to all transmission customers under Schedule 1 of the *pro forma* OATT.[159] For example, NextEra contends that intra-hour scheduling would provide long-term benefits for all customers through savings on reserve procurement. Public Interest Organizations agree, arguing that the initial costs of establishing 15-minute scheduling are an upfront investment that will yield exponential returns over time in the form of direct economic savings from increased grid efficiency and reliability, as well as energy security, greenhouse gas and other pollutant

[158] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 41.

[159] *E.g.*, Environmental Defense Fund; NextEra; Public Interest Organizations.

reductions, and job creation that accompanies increased renewable VER penetration. Center for Rural Affairs supports recovery of intra-hour scheduling costs to all beneficiaries through Schedule 1 in order to mitigate any challenge that this reform may present for small transmission providers, especially in rural communities with smaller areas of distribution. NaturEner points to the Joint Initiative as an example of allocating the hardware and software costs associated with implementation of intra-hour scheduling to all participants using the intra-hour scheduling system, i.e., the balancing authorities, transmission providers, and transmission customers. While Organization of Midwest ISO States supports the proposal, it asks that a clear showing of the costs incurred to implement intra-hour scheduling be required prior to allowing for recovery of those costs.

121. Other commenters disagree with the Commission's proposal to allow the costs associated with implementing intra-hour scheduling to be recovered through Schedule 1 and, instead, contend that such costs should be allocated to VERs and their customers.[160] These commenters argue that intra-hour scheduling will be predominantly used by and benefit VERs and their customers.[161] ELCON contends that traditional generation resources do not require intra-hour scheduling. In the Pacific Northwest, WUTC claims that intra-hour scheduling would be utilized almost exclusively by wind and other VERs,

[160] *E.g.*, Avista; ELCON; Grant PUD; Montana PSC; Natural Gas; NorthWestern; NRECA; Puget; WUTC.

[161] *E.g.*, Avista; ELCON; Grant PUD; MidAmerican; NorthWestern; NRECA; Puget; WUTC.

and not by thermal or hydropower resources. WUTC agrees that assignment of costs to those who cause them is essential to fair and just rates and to economic efficiency. Puget agrees that the only parties to benefit from 15-minute scheduling are VERs that are potentially able to reduce Schedule 9 generator imbalance charges by adjusting their schedules within the hour in response to changing wind conditions. Natural Gas argues that strict adherence to cost causation principles is central to ensuring that the proposals are limited to removing barriers and do not have the unintended consequence of subsidization and, ultimately, departure from the central precept of fuel neutrality.

122. Montana PSC states that traditional generation choosing to utilize intra-hour scheduling should be allocated a portion of implementation costs; however, absent this election VERs should be responsible for all costs related to development, operations, and maintenance of intra-hour scheduling.[162] NRECA similarly contends that, if transmission customers other than VERs make use of the new scheduling regime, it would be appropriate for those entities to share in the cost through Schedule 1 charges. Grant PUD argues that there is no guarantee that other resources may benefit from a shorter scheduling period and that some resources may actually incur costs to maintain 15-minute schedules, in which case they would pay twice for the shift to shorter schedules.

[162] Similarly, NorthWestern asserts that unless intra-hour scheduling is made mandatory for all transmission customers, the VERs opting to use intra-hour scheduling should pay for the increased scheduling flexibility and the non VER customers should not be required to subsidize any particular generator type.

123. Avista asserts that allowing recovery through Schedule 1 will allocate costs not only to all transmission customers, but also to bundled retail native load customers. Avista argues that native load customers achieve no cost savings when a VER is located within a balancing authority area and is used to serve load within the same balancing area. Avista states that in this situation the native load customers bear all of the costs associated with following the output of the VER and do not need or benefit from intra-hour scheduling. Thus, Avista requests that none of the costs of implementing intra-hour scheduling be borne by a transmission provider's bundled retail native load customers.

124. Several of these commenters recommend that the Commission consider other mechanisms for recovering the costs of implementing intra-hour scheduling as opposed to a broad cost allocation scheme through Schedule 1.[163] For example, Avista asks the Commission to allow a transmission provider to directly assign the costs of implementing these reforms to the VER transmission customers that are the cause of such reforms through an appropriate charge included in either Schedule 1 or Schedule 10. NRECA argues that there is more than one method that a public utility transmission provider could use to recover costs and requests that the Commission provide public utility transmission providers the flexibility to choose the method that works best for each system and demonstrate a just and reasonable rate pursuant to section 205 of the FPA. NRECA also

[163] *E.g.*, Avista; Grant PUD; NRECA; Puget.

urges the Commission to include costs incurred to comply with any new Reliability Standards that ensue from the Final Rule.

iii. Commission Determination

125. The Commission adopts its proposal and allows public utility transmission providers to recover any costs incurred to implement the intra-hour scheduling reforms adopted in this Final Rule pursuant to Schedule 1 of the transmission provider's OATT. The Commission is not persuaded by commenters opposing the proposal that recovery of these costs through Schedule 1 will result in an overly broad assignment of costs. Such commenters argue that only a subset of transmission customers is likely to use intra-hour scheduling and that only those customers should bear the cost of implementing intra-hour scheduling reforms. The Commission disagrees. As discussed above, intra-hour scheduling provides all transmission customers with the tools needed to mitigate exposure to Schedule 9 generator imbalance charges in light of changing conditions.[164] Implementation of intra-hour scheduling is also necessary to the extent sellers wish to develop intra-hour energy products to maximize the value of available resources or to allow load serving entities to lower purchased power costs.[165] The Commission finds that these benefits will be spread broadly across customer classes.

[164] *See supra* § IV.A.1 (Intra-Hour Scheduling Requirement).

[165] *Id.*

126. Moreover, commenters opposing the Commission's proposal fail to reconcile their position with existing approaches used to recover scheduling-related costs under Schedule 1 of the *pro forma* OATT. Transmission providers do not currently parse scheduling costs into, for example, categories for network customers and point-to-point customers even though at times scheduling reforms have focused on one set of customers and not the other.[166] Rather, transmission customers as a whole have allocated the costs of scheduling-related activities through Schedule 1: Scheduling, System Control and Dispatch Service, and relevant allocations to retail native load have been made by public utility transmission providers. Commenters have failed to justify why the Commission should depart from this precedent during implementation of intra-hour scheduling practices.

127. In response to NRECA, the Commission's focus in this proceeding is on the implementation of intra-hour scheduling and, as relevant here, the recovery of scheduling-related implementation costs pursuant to Schedule 1 of the *pro forma* OATT. The Commission did not propose to address, and does not address here, recovery of other costs associated with compliance with NERC Reliability Standards.

[166] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 770.

c. Clarify Proposed Rule Language

i. Comments

128. Commenters ask the Commission to clarify what is intended by the terms schedule and scheduling interval. Southern and EEI state that the term "schedule" is not well defined throughout the electric industry and requests that the Commission clarify that "schedule" is equivalent to "Interchange Transaction" in the NERC Reliability Standards Glossary of Terms. TVA suggests that "scheduling intervals" coincide with the "ramp start" times as defined in the Timing Requirements tables of the NERC Reliability Standards INT-005-3, Interchange Authority Distributes Arranged Interchange; INT-006-3, Response to Interchange Authority; and INT-008-3, Interchange Authority Distributes Status. TVA contends that to view the term "scheduling interval" otherwise would deviate from NERC Reliability Standards and potentially have an adverse effect on assessment periods for reliability.

129. Bonneville Power requests that the Commission clarify the responsibilities of source and sink balancing authorities in regards to holding contingency reserves associated with scheduling of VER generation. Bonneville Power states that there is a debate regarding whether and when a source or sink balancing authority should deploy contingency reserves when a VER scheduling error exhausts the available balancing reserve capacity. Bonneville Power asks the Commission to clarify that a transmission provider can establish a base obligation to provide balancing reserve capacity to balance VERs and that the transmission provider can negotiate options for additional service beyond the base obligation with individual transmission customers.

130. A few commenters request clarification of the appropriate curtailment priority for intra-hour transmission schedules under the proposed reform.[167] Specifically, these commenters inquire as to whether a firm transmission reservation that is scheduled for less than the full hour would have priority over a non-firm hourly schedule. Bonneville Power and NRECA contend that submission of a firm intra-hour schedule should not necessarily result in the curtailment of lower priority hourly schedules. MidAmerican requests that the Commission clarify whether the submission of an intra-hour schedule by a transmission customer with firm transmission rights, after a competing intra-hour schedule from a transmission customer with only non-firm transmission rights, has curtailment priority.

131. Other commenters question how ATC calculations should be performed after implementation of intra-hour scheduling.[168] Public Interest Organizations state that current policy in the West does not allow ATC associated with transmission reservations that are not scheduled day-ahead to be used by other customers. Public Interest Organizations suggest that this policy may severely constrain or prohibit the effectiveness of intra-hour scheduling. In addition, Tacoma Power suggests that it may be appropriate to align ATC calculations with intra-hour scheduling intervals. Invenergy Wind asserts that the entire operational construct needs to shift from an hourly to a 15-minute basis in

[167] *E.g.*, Bonneville Power; EEI; MidAmerican; NRECA.

[168] *E.g.*, Public Interest Organizations; Tacoma Power.

order to increase the efficiency of operating the transmission system and acquiring sufficient reserves in order to integrate VERs on a non-discriminatory basis. However, NorthWestern argues that continued use of hourly transmission service reservations would not be inconsistent with implementation of intra-hour transmission scheduling, stating that administering intra-hour transmission reservations would be difficult and costly.

132. Grant PUD makes reference to the Commission's use of the term "reasonable control" in the Proposed Rule, where the Commission states that it is unduly discriminatory to continue to require a resource to match an hourly schedule, especially when the output of the resource fluctuates beyond its reasonable control.[169] Grant PUD contends that what is reasonable depends on the current state of technology and requests that the Commission clarify that the definition of "reasonable control" is expected to improve over time.

ii. Commission Determination

133. In response to Southern and EEI, the Commission clarifies that the term "schedule" as used in this Final Rule is equivalent to its use in Schedule 9 of the OATT: "…a delivery schedule from [a] generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area."[170] The procedures for submitting and

[169] Grant PUD (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 39).

[170] OATT Schedule 9.

revising a transmission schedule are delineated in sections 13.8 and 14.6 of the *pro forma* OATT, as changed by this Final Rule. Any transmission service schedule currently submitted pursuant to OATT sections 13.8 and 14.6 can therefore be modified or created in 15-minute intervals under this Final Rule.

134. In response to TVA, the Commission clarifies that the 15-minute scheduling interval will be treated the same as the current one-hour scheduling interval with respect to ramp start and stop times as defined in the Timing Requirements tables of NERC Reliability Standards INT-005-3, INT-006-3, and INT-008-3. As an example, in the Eastern Interconnection ramp start times will begin five minutes before the start of the 15-minute scheduling interval and end five minutes after the start of the 15-minute scheduling interval.

135. Regarding responsibilities for holding contingency reserves, the Commission did not propose any changes to existing rules regarding the use of contingency reserves in this proceeding. As Bonneville Power notes, there is ongoing debate in the industry regarding when and how contingency reserves may be used under NERC Reliability Standards. The Commission concludes it is appropriate, in the first instance, for stakeholders to address these questions through the NERC processes.[171]

[171] The Commission addresses requests by Bonneville Power and others to limit the amount of capacity it must make available to transmission customers for generator regulation service under Schedule 10 in § IV.C.1 (Schedule 10-Generator Regulation and Frequency Response Service) below.

136. The Commission also did not propose any changes to curtailment policies or ATC calculation. The Commission recognizes that transmission providers have flexibility under the *pro forma* OATT to award transmission service based on transmission capability that becomes available when firm transmission service is not scheduled by 10:00 am the day prior to operation.[172] The Commission appreciates that, when a transmission provider makes service available under these circumstances, application of curtailment priorities and ATC calculation rules become more complicated. However, that is already the case under hourly transmission schedules. Therefore, the Commission did not propose any change to those practices to accommodate the possibility of intra-hour transmission schedules. All transmission schedules for firm service will continue to have curtailment priority over all transmission schedules for non-firm service[173] and transmission providers will continue to be required to follow existing rules governing the calculation of ATC.[174]

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[172] The *pro forma* OATT states that "[s]chedules for the Transmission Customers' Firm Point-To-Point Transmission Service must be submitted no later than 10:00am…of the day prior to commencement of such service." OATT Schedule 13.8.

[173] The *pro forma* OATT makes clear that "(p)arties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff." OATT Schedule 14.5.

[174] In compliance with Order No. 890, public utility transmission providers have documented rules governing their calculation of ATC in Schedule C of their OATTs. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 193.

137. In response to the request from Grant PUD for clarification of the term "reasonable control," the Commission explains that use of the term "reasonable control" is not intended to be a metric or a determining factor, but illustrative of the difficulty VERs experience when attempting to follow hourly schedules accurately. The Commission does not find it necessary to offer any further clarification.

d. NERC and NAESB Standards

i. Commission Proposal

138. In the Proposed Rule, the Commission noted that many commenters, in response to the NOI, claimed that shorter scheduling intervals may enhance reliability. The Commission therefore stated that it did not believe that an independent review of NERC Reliability Standards is necessary in order to propose implementation of intra-hour scheduling. However, the Commission sought comment on the issue to ensure that there is no inconsistency between relevant NERC standards and the proposed intra-hour scheduling tariff reform.[175]

ii. Comments

139. NERC states that certain entities currently offer 15-minute scheduling and that it is unaware of any conflicts with Reliability Standards. However, NERC asserts that wide spread use of intra-hour scheduling will likely require review and refinement of several existing Reliability Standards. Based on its preliminary review of Reliability Standards

[175] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 37.

in coordination with industry stakeholders, NERC states that it does not believe there are any insurmountable hurdles that prevent industry from implementing 15-minute transmission scheduling. NERC explains that sufficient time must be allowed for Reliability Standards to be modified through the NERC Reliability Standards Committee prioritization process, but that transitioning to broad intra-hour scheduling flexibility is achievable in a reasonable timeframe.

140. Some commenters do not anticipate that a review of NERC Reliability Standards is necessary to ensure reliability upon the implementation of intra-hour scheduling.[176] NaturEner argues that an independent review of NERC standards may not be necessary, but if such a review occurs it should not delay implementation of intra-hour scheduling. Pacific Gas & Electric agrees that implementation of intra-hour scheduling can be achieved without a review of NERC standards, but recommends that NERC and other industry experts review and update current planning and operating criteria to ensure that balancing authorities have the necessary tools to flexibly balance loads and resources with the advent of increased VER penetration.

141. Other commenters contend that review and modification of standards may be necessary, but not a prerequisite to implementation.[177] Southern and Xcel state that only modest, if any, changes would be needed to NERC Reliability Standards. Southern

[176] *E.g.*, NaturEner; Southern California Edison.

[177] *E.g.*, NERC; Pacific Gas & Electric

indicates that several standards may need to be reviewed and revised as they currently contemplate hourly intervals. Xcel contends that standards related to the maximum lead times required for entry and approval of a schedule may require changes. Xcel explains that the lead times for entry and approval of a tag may exceed the length of a scheduling interval, thus diminishing the usefulness of intra-hour scheduling. AEP and Duke Energy suggest that sensitivity studies should be performed by an industry forum or working group to determine the reliability impacts of the proposed scheduling changes on real-time system operations.

142. Several commenters argue that review and revision of NERC Reliability Standards, as well as NAESB business practice standards, may be necessary for the implementation of intra-hour scheduling at 15-minute intervals.[178] These commenters point out that many Reliability Standards and business practices are largely predicated on hourly scheduling intervals and govern transactions both internal to a particular balancing authority as well as across neighboring balancing authorities. Although most commenters did not identify specific changes to standards that would be necessary, some commenters suggest that NERC Reliability Standards related to some or all of the following areas be reviewed: Interchange Scheduling and Maintenance Coordination (INT), Resource and Demand Balancing (BAL), Emergency Preparedness and

[178] *E.g.*, Bonneville Power; Duke; EEI; MidAmerican; NRECA; PNW Parties; Southern.

Operations (EOP), and Transmission Operations (TOP) standards.[179] Additionally, commenters indicate that reliability scheduling tools, such as the Interchange Distribution Calculator used in the Eastern Interconnection and the WebSAS system used in the Western Interconnection for scheduling, curtailment and "check out" processes may also require modification.[180]

143. NRECA cautions that any modifications to NERC standards should allow for the implementation of intra-hour scheduling but not mandate this practice. NRECA suggests that NERC be allowed to complete any updates to its standards associated with implementation of intra-hour scheduling prior to NAESB undertaking a review to ensure uniformity of approaches. NV Energy notes that, in order to schedule at 30 minute intervals or less, the protocols to effectuate such transactions must be agreed upon by all entities in WECC. Therefore, NV Energy requests that the Commission defer issuance of the Final Rule until the industry has had the opportunity to address NERC, WECC and NAESB standards issues.

144. PNW Parties state that the Joint Initiative participants found it necessary to review NERC and NAESB standards as part of their development of a 30-minute scheduling program, but did not identify in comments whether any changes to standards or business practices were needed. PNW Parties suggests, however, that applicable standards and

[179] *E.g.*, Duke; EEI; NERC; NRECA; PNW Parties; Southern.

[180] *E.g.*, NERC; NRECA; Southern.

business practices be reviewed and revised as necessary prior to implementing more granular scheduling.

145. Some commenters within the VER industry request clarification and/or modification of NERC scheduling protocols to allow for a resource to be indentified as a "sink."[181] These commenters claim that this is necessary because under the Commission's proposed reforms VERs will be transacting on an intra-hour basis in order to supplement their variable supply. Iberdrola explains that, in order to enter into bilateral transactions for balancing energy where a VER's 15-minute schedule is less than its hour-ahead schedule, the additional balancing energy purchased from a generator with excess energy would need to be tagged as the "source" and the VER would need to be tagged as the "sink." Iberdrola claims that this is necessary because VERs will be transacting bilaterally in the sub-hourly timeframe in an effort to maintain the schedule that was entered prior to the operating hour. AWEA agrees, arguing that some of the benefits of intra-hour scheduling will not be realized without this additional clarification. In response to the potential concerns of transmission providers regarding generators being tagged as sinks, AWEA and Iberdrola argue that reliability concerns would only be present when the ultimate delivery point is unknown.[182] AWEA explains that the case presented by a VER transacting as a sink for intra-hour scheduling purposes is entirely

[181] *E.g.*, AWEA; Iberdrola.

[182] *E.g.*, AWEA; Iberdrola.

different, as the ultimate delivery point is already known. In this case, AWEA points out that there is a schedule to deliver energy to a real load and explains that this schedule is delivering energy to the load which the VER is unable to serve. Therefore, AWEA and Iberdrola conclude that such scheduling practices do not present reliability concerns.

iii. Commission Determination

146. The Commission concludes that an independent review of NERC standards and NAESB business practices is not necessary prior to the implementation of intra-hour scheduling. As noted by NERC, several entities currently offer intra-hour scheduling without any apparent conflict with Reliability Standards. NERC comments that it does not believe there are any existing standards that prohibit industry from implementing intra-hour scheduling, and no commenters have pointed to specific NAESB business practices that prevent industry from implementing intra-hour scheduling. The Commission therefore concludes that it is not necessary to delay adoption of the intra-hour scheduling requirements of this Final Rule pending further review of NERC Reliability Standards and NAESB business practices. To the extent industry believes it is beneficial to refine one or more existing NERC Reliability Standards or NAESB business practices to reflect intra-hour scheduling, stakeholders can use existing processes to pursue such refinements.

147. With regard to the requests from AWEA and Iberdrola to allow a VER resource to be designated as a “sink” for purposes of transmission scheduling, rules for scheduling

transmission segments are set forth in NAESB's Coordinate Interchange Standards,[183] which have been incorporated into the Commission's regulations by reference.[184] The Proposed Rule did not propose any changes to those rules and the Commission declines to interpret the application to any particular transactions in this generic rulemaking proceeding.

3. Other Issues

a. Comments

148. Several commenters question the application of intra-hour scheduling reforms to HVDC transmission lines. Clean Line states that HVDC transmission lines can precisely control power and, thus, are typically expected to submit schedules to public utility transmission providers. Clean Line requests that HVDC transmission lines receive equal treatment and be allowed to submit intra-hour schedules on the same basis as generators. In contrast, ALLETE and Midwest ISO Transmission Owners both request that the Commission grant an exemption from 15-minute schedules for HVDC transmission lines. These commenters argue that 15-minute scheduling of HVDC transmission lines could lead to an increase in the duty on the load tap changers of HVDC converter transformers, potentially resulting in an increase in maintenance costs and an increased potential of transformer failure.

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[183] NAESB WEQ-004, App. C, § 2 (Commercial Timing Table).

[184] *See* 18 CFR § 38.2 (2011).

149. Bonneville Power raises questions regarding the impact of intra-hour scheduling on dynamic scheduling practices. Bonneville Power states that 15-minute scheduling will lead to increased ramping and inhibit the availability of dynamic transfer capability in areas where dynamic transfer capability is limited, such as the Bonneville Power system and other parts of the West. Bonneville Power contends that 30-minute scheduling relieves this problem and requests that the Commission gain a better understanding of the impacts that 15-minute scheduling will have on dynamic transfers. In contrast, First Wind requests that the Commission encourage dynamic transfers in addition to implementing intra-hour scheduling, suggesting that dynamic transfers can reduce regulation service requirements for transmission owners and transfer regulation requirements to purchasers of VER energy. First Wind also argues that intra-hour scheduling and dynamic transfers will allow for better tracking of real-time generation and reduce the need for ancillary services while increasing opportunities for flexible generation and demand response.

150. M-S-R Public Power Agency states that shortening the scheduling interval does not reduce the intermittency of the VERs themselves. M-S-R Public Power Agency offers that as a matter of physics a VER requires a back-up resource to "balance" its intermittency, irrespective of scheduling, adding that while a shorter scheduling interval may mitigate the number of megawatts needed to assure reliability, it will not mitigate the location or cost of back-up reserves. M-S-R Public Power Agency goes on to state that VER penetration levels of 20-25 percent start to exhaust the capability of even the most robust systems and that the proposed mitigation may be insufficient. M-S-R Public

Power Agency explains that the raw energy of VERs must be converted to conditioned energy (traditional resources) at the source, and not shifted to other locations through mitigation, or there will be a degradation of services to all VERs within that system. M-S-R Public Power Agency states that intermittent resources require that the transmission owner have nearly infinite capability to provide backup resources; however, even the most robust balancing authority has limitations of how fast, how often, and when it can provide back up resources. M-S-R Public Power Agency offers that, with both the cost of transmission and reliability (back-up generation) challenges, VERs may be uneconomic. M-S-R Public Power Agency encourages the Commission to solicit input on this issue.

Commission Determination

151. All transmission customers that are currently eligible to submit hourly energy schedules will be eligible to participate in intra-hour scheduling, including HVDC lines that currently submit hourly energy schedules. To the extent a transmission provider believes an exemption is appropriate, it has the right to request a waiver of all or part of the OATT requirements as described in 18 CFR § 35.28(d): "A public utility subject to the requirements of this section and Order No. 889, FERC Stats. & Regs. ¶31,037 (Final Rule on Open Access Same-Time Information System and Standards of Conduct) may file a request for waiver of all or part of the requirements of this section, or Part 37 (Open Access Same-Time Information System and Standards of Conduct for Public Utilities), for good cause shown." Waiver requests will be evaluated in separate proceedings if and when they are submitted based on the facts and circumstances of each request.

152. With regard to the use of dynamic schedules, the Commission did not propose and is not adopting any change in policy with regard to dynamic scheduling. The Commission is not persuaded by arguments from Bonneville Power that 15-minute scheduling intervals will negatively affect dynamic transfer capability. However, the Commission acknowledges that a transmission provider's implementation of charges for generator regulation service, as discussed in the following section, may have the result of encouraging the use of dynamic scheduling to avoid such charges.

153. In response to M-S-R Public Power Agency, the Commission appreciates that the location of a particular resource can be relevant in determining whether it can be used to satisfy reserve obligations. That is, a public utility transmission provider providing ancillary services under the *pro forma* OATT, or a transmission customer self-supplying such ancillary services needs transmission capacity to ensure deliverability of a particular resource. Whether that is the case will be fact specific and we expect the transmission provider to take the appropriate steps to ensure such transmission capacity is available.

B. Data Reporting to Support Power Production Forecasting

154. The second of the two reforms adopted in this Final Rule relates to the submission of meteorological and forced outage data,[185] by new interconnection customers whose

[185] The Proposed Rule used the term "operational data" and specified forced outages as a particular type of operational data. To reflect the limited nature of data to be reported under this Final Rule more accurately, the Commission instead refers more specifically to "forced outage data" in our determinations here and accompanying revisions to the *pro forma* LGIA. We also note that Section 9.7.1 of the LGIA requires Transmission Providers and Interconnection Customers to coordinate and report planned

(continued…)

generating facilities are VERs, to the public utility transmission provider with which the customer is interconnected if the public utility transmission provider is doing power production forecasting. As discussed below, the Commission amends the *pro forma* LGIA to effectuate this data reporting requirement. The Commission concludes that, without these reporting requirements in place, the terms of the *pro forma* LGIA may impair the ability of public utility transmission providers to develop and deploy power production forecasting, which in turn can lead to rates for jurisdictional services that are unjust and unreasonable or unduly discriminatory.

1. Data Requirements

a. Commission Proposal

155. To facilitate the development and deployment of power production forecasting by public utility transmission providers, the Proposed Rule set forth revisions to the *pro forma* LGIA that would require interconnection customers whose generating facilities are VERs to provide certain meteorological and operational data to the public utility transmission provider with whom they are interconnected, if doing forecasting. The Commission proposed that such data would be transmitted from the interconnection customer to the public utility transmission provider at or near real-time. The Commission stated that this proposal built on existing Commission data-sharing requirements by

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outages. Within the context of this Final Rule, the Commission references the term "forced outage" as defined by NERC. *See NERC* Glossary of terms *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

outlining specific meteorological and operational data necessary to develop power production forecasts.[186]

156. With regard to the reporting of meteorological data, the Commission proposed revisions to the *pro forma* LGIA that would result in different types of meteorological information being provided by interconnection customers based on the type of VER they own and/or operate. The Commission proposed to require interconnection customers whose generating facilities are wind-based VERs to provide public utility transmission providers with site-specific meteorological data including, but not limited to, temperature, wind speed, wind direction, and atmospheric pressure. The Commission proposed to require interconnection customers whose generating facilities are solar-based VERs to provide public utility transmission providers with site-specific meteorological data including, but not limited to, temperature, atmospheric pressure, and cloud cover. The Commission recognized that different power production forecasts may require meteorological instruments to be located at hub height, up-wind of resources, or at ground level. However, the Commission refrained from proposing specific requirements in this respect and, instead, proposed to allow the public utility transmission provider and interconnection customers to negotiate these details taking into account the size and configuration of the VER facility, its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

[186] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at PP 60-61.

The Commission stated that resource-specific data requirements contained in individual LGIAs must be negotiated on a not unduly discriminatory basis.[187]

157. With respect to the reporting of operational data, the Commission proposed to revise the *pro forma* LGIA to require interconnection customers whose generating facilities are VERs to report to the public utility transmission provider any forced outages that reduce the generating capability of the resource by 1 MW or more for 15 minutes or more. The Commission noted that provision of VER outage data at this level of granularity would allow a public utility transmission provider to ascertain the extent to which current VER power production is a result of unit availability as opposed to changing weather conditions.[188] The Commission preliminarily found that having such information would eliminate a significant source of forecasting errors by ensuring that the public utility transmission provider has accurate information regarding the capacity actually available to produce electricity during the time-frame of the operational forecasts.[189]

[187] *See id.* P 61.

[188] *See id.* P 62 (citing *Cal. Indep. Sys. Operator Corp.*, 131 FERC ¶ 61,087, at P 64 (2010)).

[189] *Id.* P 62.

158. The Commission sought comment on the extent to which the lists of basic meteorological and operational data articulated above may be inadequate or incomplete in achieving the stated power production forecasting goals.[190]

b. Comments

159. Commenters addressing the reporting of meteorological data generally support requiring the provision of data as necessary to enable public utility transmission providers to employ power production forecasts.[191] While disagreeing that public utility transmission providers should be responsible for power production forecasting, Montana PSC argues that, should the Commission impose forecasting requirements, public utility transmission providers should have access to all meteorological data that are site-specific to the VER, provided that the parties have a confidentiality agreement in place to protect proprietary information. BP Companies and First Wind request that the Commission clarify that the proposal is only relevant to instances in which the public utility transmission provider is developing and/or implementing VER power production forecasting.

[190] *Id.* P 63.

[191] *E.g.*, AWEA; Bonneville Power; California ISO; CEERT; Clean Line; California PUC; Exelon; First Wind; Iberdrola; Independent Energy Producers; Independent Power Producers Coalition-West; ISO/RTO Council; ISO New England; Large Public Power; Midwest ISO; Midwest ISO Transmission Owners; NaturEner; NextEra; NRECA; Pacific Gas & Electric; PJM; Powerex.

160. Several commenters support the Commission's identification of certain categories of meteorological data to be provided by wind and solar resources.[192] For example, with regard to wind resources, Iberdrola agrees that wind speed, wind direction, temperature and pressure are all key atmospheric variables related to wind farm output and are the most important fields to measure. With regard to solar resources, NextEra, SEIA, and Xcel generally support the minimum categories of data identified in the Proposed Rule, but they suggest that the Commission revise the reference to cloud cover because it is ambiguous. Specifically, NextEra and SEIA recommend that the Commission require solar resources to report diffuse, direct, and global horizontal irradiance. NextEra adds that humidity should also be provided for a solar VER using concentrating thermal solar technology, while SEIA suggests that plane of array irradiance or direct normal radiation may also be necessary. These commenters note that irradiance is often a better measure because it actually drives energy production.

161. Commenters generally support the Commission's proposal to allow the public utility transmission provider and interconnection customer to negotiate additional meteorological and operational data reporting requirements.[193] Commenters identified a variety of additional meteorological and facility-specific data that may be useful in developing and deploying power production forecasts. These commenters generally note

[192] *E.g.*, AWEA; Iberdrola; ISO New England; RENEW.

[193] *E.g.*, Bonneville Power; ISO New England; ISO/RTO Council; Large Public Power Council; Midwest ISO; NRECA; PNW Parties; RENEW; Xcel.

that regional differences may dictate additional data needs,[194] with several asking the Commission to acknowledge that additional data beyond that specifically identified in the Proposed Rule may be needed by a public utility transmission provider.[195]

162. Several commenters raise concerns regarding the Commission's discussion of the location of meteorological towers and other equipment necessary to record and report data to public utility transmission providers.[196] NextEra asks that the Commission refrain from allowing public utility transmission providers to require VERs to install multiple meteorological towers, arguing that data beyond what is available through one meteorological tower has little value for advanced power production forecasting methods. Invenergy similarly argues that a single meteorological tower per facility is usually sufficient for predicting plant output.

163. With regard to the frequency of reporting meteorological data, several commenters suggest that the frequency of data reporting should match the use of the data, which may not be at or near real-time.[197] For example, AWEA, Iberdrola, and NextEra state that second-by-second or minute-by-minute meteorological recordings yield minimal benefits

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[194] *E.g.*, Bonneville Power; First Energy; ISO New England; ISO/RTO Council; NextEra; MidAmerican; Midwest ISO; Midwest ISO Transmission Owners; NorthWestern; NRECA; Pacific Gas & Electric; Xcel.

[195] *E.g.*, Bonneville Power; ISO New England; Midwest ISO; NextEra; NRECA.

[196] *E.g.*, AWEA; Invenergy; NextEra.

[197] *E.g.*, AWEA; Clean Line; Iberdrola; NextEra; NaturEner; NorthWestern; Public Interest Organizations.

for forecasting accuracy and could be costly and burdensome. AWEA and Clean Line suggest that a reasonable requirement for the frequency at which real-time meteorological and operational data is reported from a wind plant is 10 minutes or more. NorthWestern, however, states that it would be helpful to require each VER to update the forecasting data that it has provided to the public utility transmission provider when it provides a new energy schedule.

164. AWEA and Iberdrola also contend that distinctions should be made between the types of data that should be provided in real-time and the types of data that should be provided historically. These commenters state that archived time series data are crucial to statistical forecasting techniques and that this application is not done in real-time. AWEA and Iberdrola state that data needed for forecast training can be compiled into larger datasets and transmitted at less frequent intervals at a much lower cost. RenewElec and Bonneville Power generally agree that there is significant value in historical data recorded by VERs.

165. With regard to the operational data reporting requirements, some commenters urge the Commission to adopt the proposed requirement that VERs report to the public utility transmission provider any forced outages that reduce the generating capacity of a resource by 1 MW or more for 15 minutes or more.[198] For example, Bonneville Power states that having access to forced outage information will enable public utility

[198] *E.g.*, Bonneville Power; California ISO; NRECA.

transmission providers to determine whether forecast inaccuracy results from unit availability, changing weather conditions, or a combination of the two. Bonneville Power further states that without such information it will be difficult to verify forecasts and improve forecast accuracy. California ISO requests that the Commission not overturn its recent decision approving California ISO's 1 MW threshold for reporting a forced outage of an eligible intermittent resource. California ISO argues that outage reporting requirements that are less stringent than those proposed would increase the likelihood that the forecasting algorithm would accumulate inaccurate data.

166. Other commenters acknowledge that forced outage data are useful in developing power production forecasts, but disagree on the exact reporting requirements.[199] Some commenters contend that a 1 MW reporting threshold would pose an unnecessary burden on a wind plant owner/operator, yield minimal benefits for forecast accuracy, and pose compliance difficulties.[200] Instead of the proposed requirement, NaturEner recommends requiring that only planned outages of greater than 15 percent of the generator's capacity should be reported as soon as they are known by the generator. AWEA suggests that reporting apply only to forced outages that exceed 10 percent of the nameplate capacity of a plant, a requirement that AWEA states is similar to the one imposed on conventional generators. NextEra similarly asks that the outage reporting requirements be identical to

[199] *E.g.*, AWEA; Exelon; NaturEner; SEIA; Xcel; MidAmerican; NextEra.

[200] *E.g.*, AWEA; Iberdrola; NaturEner; MidAmerican; PJM.

those that apply to conventional resources. MidAmerican recommends that VER transmission customers be required to report forced outages lasting more than 24 hours and involving the lesser of either 20 MW or 50 percent of nameplate capacity. Xcel recommends that the Commission ask NERC to analyze and determine the appropriate threshold level for reporting VER outages to public utility transmission providers and balancing authorities.

167. SEIA contends that the forced outage reporting requirement may be appropriate for large solar photovoltaic generators, but not for concentrating solar plants that experience frequent changes in power output. SEIA states that, with respect to concentrating solar power-generating facilities, the Commission should consider a threshold for reporting such fluctuations based either on the total capacity of the facility or particular types of maintenance or repair activities that would result in an outage at a percentage of the facility.

168. Exelon asks the Commission to clarify what constitutes a forced outage for purposes of the requirement to report operational data, suggesting it should only include unanticipated outage events. NRECA notes that the Proposed Rule did not identify the frequency for reporting operational data to the public utility transmission provider. NRECA contends that the public utility transmission provider should be notified as soon as the VER is aware of an outage.

169. Several commenters recommend that the Commission provide regional flexibility with respect to the operational data reporting requirements.[201] For example, Iberdrola states that VER forced outage reporting requirements should be regional and: (1) based on the penetration of VERs in the region; (2) based on the ability of the transmission provider to incorporate the data into power production forecasting from VERs that is in turn used for reliably operating the system; and (3) limited to an interval that enables the use of predictive outage reporting capability.

170. Some commenters argue that the Commission should acknowledge the importance of standardized regional reporting mechanisms when considering these proposed reforms.[202] For example, Midwest ISO notes that IEC Standard 61400-25 already exists to facilitate the exchange of information between individual wind turbines, their constituent components, wind power plants, area control, and other external systems. Midwest ISO suggests that use of a common format for communicating data between the VER and public utility transmission provider would promote the development of power production forecasting. However, Invenergy asks that the Commission make clear that public utility transmission providers are required to accept reasonable alternative means of data communication and not implement uniform standards that impose unnecessary costs on wind projects.

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[201] *E.g.*, Iberdrola; ISO New England; Midwest ISO Transmission Owners; PJM; Southern California Edison.

[202] *E.g.*, Alstom; EEI; Midwest ISO.

c. Commission Determination

171. The Commission adopts, as modified below, the proposed requirement that interconnection customers whose generating facilities are VERs provide meteorological and forced outage data to the public utility transmission provider with which the customer is interconnected, where necessary for that public utility transmission provider to develop and deploy power production forecasting. As discussed below, power production forecasting can be used by public utility transmission providers to operate their systems and manage reserves more efficiently. To the extent a public utility transmission provider seeks to rely on power production forecasting, the Commission concludes it is appropriate to require new interconnection customers whose generating facilities are VERs to provide related data to the public utility transmission provider under the circumstances below. The Commission therefore directs public utility transmission providers to modify their *pro forma* LGIAs to effectuate the data reporting requirement.

172. As the Commission noted in the Proposed Rule, industry studies demonstrate the potential for significant benefits from the incorporation of power production forecasts into scheduling and unit commitment processes. In WECC alone, NREL estimated the use of VER power production forecasts has the potential to reduce operating costs by up

to 14 percent or $5 billion per year.[203] NERC has similarly concluded that forecasting the output of variable generation is critical to bulk power system reliability in order to ensure that adequate resources are available for ancillary services and ramping requirements.[204] NERC has therefore recommended that forecasting techniques be incorporated into day-to-day operational planning and real-time operations routines/practices including unit commitment and dispatch.[205] The Commission notes that the benefits of power production forecasting can accrue across a variety of time frames, including the operating day, day-ahead, and seasonally.

173. However, power production forecasts are only as good as the data on which they rely. The ability of public utility transmission providers to use power production forecasting in the commitment and de-commitment of resources may be limited without adequate meteorological and forced outage data from VERs. The current lack of meteorological and forced outage data reporting requirements in the *pro forma* LGIA therefore may limit efforts by public utility transmission providers to more efficiently manage operating costs associated with the integration of VERs interconnecting to their systems. Under the existing requirements of the *pro forma* LGIA, public utility

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[203] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 45 (citing National Renewable Energy Laboratory, *Western Wind and Solar Integration Study* ES-18 (2010), *available at* http://www.nrel.gov/wind/systemsintegration/wwsis.html).

[204] NERC, *Accommodating High Levels of Variable Generation* 54 (2009), *available at* http://www.nerc.com/files/IVGTF_Report_041609.pdf.

[205] *Id.* at 59.

transmission providers are permitted to request this information, but there is no obligation for interconnection customers whose generating facilities are VERs to provide it. The Commission remedies this deficiency by adopting reporting requirements for new interconnection customers whose facilities are VERs, commensurate with the power production forecasting employed by the public utility transmission provider, to allow for more accurate commitment and de-commitment of resources providing reserves, ensuring that reserve-related charges imposed on customers remain just and reasonable and not unduly discriminatory or preferential. The Commission implements this requirement by requiring public utility transmission providers to modify their *pro forma* LGIAs to include the reporting requirements discussed below.

174. The reporting requirements adopted in this Final Rule are specifically designed to support the development and deployment of power production forecasting by public utility transmission providers. As a result, nothing in this Final Rule should be construed as creating an obligation for interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data in cases where the public utility transmission provider is not engaging in power production forecasting. The Commission recognizes that VER potential and penetration varies across public utility transmission provider systems and that, at this time, not all public utility transmission providers have sufficient levels of VERs to warrant engaging in power production forecasting. The Commission is nonetheless amending the *pro forma* LGIA to ensure that those public utility transmission providers seeking to develop and deploy power production forecasting in response to increasing VER penetration have adequate information to do

so. To make the conditional nature of the reporting requirements clear, the Commission revises the proposed Article 8.4 of the *pro forma* LGIA to state that all requirements for meteorological and forced outage data must be consistent with the power production forecasting employed by the Transmission Provider, if any, to manage reserve commitments. The Commission believes that this strikes a reasonable balance between the requirement to provide the data and the public utility transmission provider's use of the data to manage reserve commitments more efficiently.

175. Turning to the particular reporting requirements imposed on interconnection customers whose generating facilities are VERs, the Commission affirms the approach set forth in the Proposed Rule allowing public utility transmission providers flexibility in identifying the specific meteorological and forced outage data to be reported. As proposed, Article 8.4 of the *pro forma* LGIA would specify certain categories of data to be provided by interconnection customers with VERs having wind or solar as the energy source, with the exact specifications of data to be provided taking into account the size and configuration of the VER, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. Some commenters generally support this approach, stating that the type of power production forecasting deployed by public utility transmission providers and the tools used to perform forecasts could vary widely, and therefore any reporting requirements

associated with power production forecasting should be flexible.[206] This approach will provide public utility transmission providers the flexibility to negotiate, in the first instance, with interconnection customers whose generating facilities are VERs to identify the particular data to be reported by the customer.

176. The Commission finds that this flexible approach to establishing data reporting requirements will ensure that all reporting of meteorological and forced outage data corresponds with the power production forecasting being employed by the public utility transmission providers. To be clear, however, public utility transmission providers cannot unduly discriminate among interconnection customers with regard to data reporting requirements. By linking the requirement to provide meteorological and forced outage data to the use of these data by the public utility transmission provider in power production forecasting to manage reserve commitments, the Commission seeks to minimize opportunities for undue discrimination as well as needless burden on interconnection customers. At the same time, to the extent meteorological and forced outage data are needed for the public utility transmission provider to engage in power production forecasting, they must be provided by the interconnection customer, even if that means investment in additional equipment by the customer.[207] To the extent there

[206] *E.g.*, Iberdrola; NextEra.

[207] The Commission acknowledges the concern of some commenters that the installation of multiple meteorological towers would increase costs for an interconnection

(continued…)

are concerns of discriminatory or unnecessary application of data reporting requirements, interconnection customers can request that the public utility transmission provider file with the Commission an unexecuted LGIA in order to resolve the disagreement.[208]

177. Notwithstanding the flexibility provided for party-specific negotiations of data reporting requirements, the record in this proceeding also confirms that some categories of meteorological data from VERs having wind or solar as the energy source will be relevant to most, if not all, power production forecasting deployed by a public utility transmission provider for these resources. Therefore, the Commission adopts the proposal to require certain categories of meteorological data from VERs having wind or solar as the energy source. Specifically, an interconnection customer with a VER having wind as the energy source must provide, at a minimum, site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. An interconnection customer with a VER having solar as the energy source must provide, at a minimum, site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The exact specifications of data to be provided by the interconnection customer will remain subject to negotiation between the parties, which as noted above must take into account the size and configuration of the VER, its characteristics, location, and its importance in maintaining generation resource adequacy

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customer. Whether data from a single meteorological tower is sufficient to support the power production forecasting deployed by the public utility transmission provider should be addressed as part of the negotiation of the LGIA.

[208] *See* 16 U.S.C. 824d (2006); 18 CFR 35.13 (2010).

and transmission system reliability in its area. It may also include additional meteorological data commensurate with the power production forecasting employed by the public utility transmission provider. As with other data reporting requirements, the public utility transmission provider may file an unexecuted LGIA pursuant to FPA section 205 seeking to demonstrate the necessity of requests for additional information if the parties cannot reach mutual agreement as to the specifications of data to be provided.[209]

178. By defining certain categories of data that must be provided, while leaving the exact specifications of data to negotiation between the interconnection customer and the public utility transmission provider, the Commission has sought to balance the competing interests of clarity and flexibility. The Commission appreciates that defining all data requirements with precision in this Final Rule might result in rules that are easier to implement. However, it also could lead to interconnection customers incurring costs to provide data at a level of granularity, for example, that is of no use to the public utility transmission provider given the type of power production forecasting deployed. By linking the reporting requirements to the data needs of the public utility transmission provider, the Commission seeks to facilitate the deployment of power production forecasting without unduly burdening the interconnection customer.

[209] *Id.*

179. In the Proposed Rule, the Commission included "cloud cover" within the categories of data required of interconnection customers with a VER having solar as the energy source. The Commission agrees with commenters that the term "cloud cover" is imprecise and thus we modify Article 8.4 of the *pro forma* LGIA to refer to "irradiance." However, the Commission declines to distinguish between types of irradiance and also declines to include "humidity" in the minimal categories of data. These additional characteristics may be more relevant for some types of facilities than others, so we leave to public utility transmission providers and their interconnection customers to identify the specifications of data relevant for reporting.

180. With regard to the frequency and timing of data reporting, the Commission modifies the Proposed Rule and allows public utility transmission providers and interconnection customers whose generating facilities are VERs to negotiate the frequency and timing of data submittals. The Proposed Rule would have required the reporting of data at or near real-time. In response, commenters such as AWEA and Iberdrola note that some power production forecasts use archived time series data that may be compiled and transmitted to public utility transmission providers at a significant costs savings when compared to the ongoing reporting of data at or near real-time, whereas NorthWestern suggests that data could be provided on a ten-minute or longer basis. Based on comments received, the Commission concludes it is more appropriate for the frequency and timing data submittals to be negotiated by the parties to ensure that the reporting of data is consistent with the type of power production forecasting being

deployed by the public utility transmission provider. The Commission revises Article 8.4 of the *pro forma* LGIA accordingly.

181. In the Proposed Rule, the Commission sought to require the reporting of forced outages of 1 MW or more for 15 minutes or more. In response, commenters disagree as to the relevant level of granularity for outage data. Rather than establish a specific megawatt reporting threshold or frequency that could result in the reporting of data that are not used by the public utility transmission provider, the Commission concludes it is more appropriate for the public utility transmission provider and interconnection customer to negotiate the exact specifications of forced outage data to be provided, taking into account the size and configuration of the VER, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. As noted in this Proposed Rule, this will provide the flexibility necessary to ensure that the reporting of forced outage data is commensurate with the power production forecasting being employed by the public utility transmission provider, consistent with any regional practices that may exist. Therefore, the Commission modifies the Proposed Rule to align the reporting of forced outages with the power production forecasting being employed by the public utility transmission provider. The Commission also declines to adopt alternative minimum thresholds or pre-define forced outages for purposes of reporting requirements as requested by some commenters.

182. Some commenters request that the Commission standardize protocols for reporting meteorological or forced outage data required by this Final Rule. The Proposed Rule did not contain standard protocols for data reporting and, as a result, the merits of such a

requirement have not been fully addressed in the record. Whether standardization of data communications would facilitate or hinder development of power production forecasting may implicate a variety of data and communications issues that would benefit from broad industry input through standards development processes such as those used by NAESB and other organizations.

d. LGIA

183. In order to effectuate the reporting requirements discussed above, the Proposed Rule set forth amendments to the *pro forma* LGIA adding a new section Article 8.4, *Provision of Data from a Variable Energy Resource*. Consistent with the approach of Order Nos. 2003 and 661,[210] the Commission proposed not to require retroactive changes to LGIAs that are already in effect. However, the Commission sought comment as to whether this approach would prevent public utility transmission providers from effectively implementing power production forecasting.[211] The Commission also preliminarily found that the *pro forma* LGIA includes adequate confidentiality protections for sensitive data obtained from VERs.[212]

[210] Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 120; Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 910.

[211] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 64.

[212] *Id.* P 60 (citing *Pro Forma* LGIA Article 22, which sets forth the confidentiality provisions applicable to data exchanged through the interconnection process).

184. The Commission noted that it was proposing revisions only to interconnection customers whose generating facilities are VERs greater than 20 MW and, as a result, proposing revisions only to the *pro forma* LGIA and not the *pro forma* Small Generator Interconnection Agreement (SGIA). The Commission sought comment on whether the proposed reforms should also apply to interconnection customers whose generating facilities are VERs of 20 MW or less, so as to require revisions to the *pro forma* SGIA.

e. Comments

185. The Commission received a variety of comments on its proposal to not require retroactive changes to LGIAs that are in effect. NaturEner argues that without data from existing resources, power production forecasts would be less reliable or robust, resulting in artificially high required reserves and attendant expenses. AWEA, Clean Line, and Iberdrola state that they would not oppose requiring data from resources that have executed an LGIA, provided that the interconnection customers are only required to report data that are currently gathered by the VER. AWEA explains that data already are being collected by many wind plants deployed since 2005 and that many public utility transmission providers have already imposed reporting requirements. However, Southern MN Municipal asserts that the proposed reforms should not be extended to resources that have already executed an interconnection agreement. Bonneville Power asserts that Articles 9.3 and 9.4 of the LGIA give the transmission provider a unilateral right to update its instructions and operating protocols and procedures regardless of whether the proposed Article 8.4 is applied retroactively.

186. Midwest ISO Transmission Owners request that the Commission address the circumstances under which a VER with an existing interconnection agreement might become subject to the new power production forecasting requirement if it is applied prospectively. Midwest ISO Transmission Owners state that, at the very least, any increase in a facility's generating capacity or material modification that would necessitate a new LGIA should be sufficient to subject the VER generator to the new power production forecasting-related data requirements under the applicable tariff.

187. Some commenters suggest implementing reporting requirements for meteorological and forced outage data through the *pro forma* OATT in order to impose those requirements on existing resources or otherwise allow for changes in reporting requirements over time.[213] AWEA contends that, if the Commission determines to apply the reporting requirements to existing resources, it would be more appropriate to place the requirements in the *pro forma* OATT. Sunflower and Mid-Kansas agree, noting that the *pro forma* LGIA already requires parties to operate their facilities consistent with Applicable Laws and Regulations, including OATT requirements. Large Public Power argues that it is important that all VERs provide the operational information required by a transmission provider and, therefore, also recommends placing reporting requirements in the transmission tariff. Southern California Edison contends that placing reporting requirements in the *pro forma* OATT would allow greater flexibility in structuring

[213] *E.g.*, AWEA; Large Public Power; Southern California Edison; Sunflower and Mid-Kansas.

agreements by referencing requirements in the California ISO Tariff, as they may change from time to time.

188. Other commenters ask the Commission to allow reporting requirements to be stated in market rules or business practices.[214] ISO New England requests that the Commission afford flexibility for public utility transmission providers to determine the mechanism by which to collect the required VER data. National Grid states that rather than requiring a proscriptive amendment of the *pro forma* LGIA, the Commission should require each region to work with its stakeholders to develop appropriate methods for forecasting the energy output from VERs. Pacific Gas & Electric requests that in its Final Rule the Commission provide latitude for the California ISO and other similarly-situated transmission providers to continue their existing programs for gathering relevant meteorological and operational data, and proposing incremental refinements to them, so long as they conform to the purposes of the Final Rule. Xcel similarly argues that the specific data requirements for individual public utility transmission providers should be identified through a business practice or other OASIS posting to allow adjustments due to changing system operating needs, improvements in meteorological forecasting technologies, or modifications in NERC reliability requirements.

189. With regard to the Commission's question as to whether the *pro forma* SGIA needs to be revised, many parties argue that the provision of data under the SGIA may be

[214] *E.g.*, California PUC; Dominion; ISO New England; National Grid; Pacific Gas & Electric.

appropriate in some instances.[215] PJM and Snohomish County PUD note that the costs of reporting the proposed data to public utility transmission providers by small VERs could be higher than for larger resources. As such, they argue that the Commission should carefully consider these costs when applying reporting requirements. Several other commenters acknowledge difficulties associated with gathering data from resources subject to the SGIA, and propose a variety of thresholds to determine whether reporting requirements should apply to the resource.[216] For example, AWEA states that it makes sense to apply similar data reporting requirements to smaller-scale generators where it can be demonstrated that the data will be used for improving VER forecast accuracy and that the benefits exceed the cost of data collection. Others state that small resources should use alternative reporting requirements.[217] Southern California Edison recommends that the Commission consider an approach that aggregates individual site data from small generators in a geographic area, which reduces cost impacts to smaller projects.

[215] *E.g.*, California ISO; EEI; Duke; ISO New England; MidAmerican; NRECA; Pacific Gas & Electric; PNW Parties; Snohomish County PUD; Southern California Edison; Tacoma Power; Xcel.

[216] *E.g.*, AWEA; RenewElec; SEIA; Tacoma Power; Xcel.

[217] *E.g.*, Alstom Grid; RENEW.

190. Commenters contend that the public utility transmission provider should have the flexibility to identify and require data from small generators.[218] For example, Bonneville Power argues that the Commission should require small VERs to provide meteorological and operational data according to the requirements established by their public utility transmission provider. These commenters generally agree that public utility transmission providers may have different forecasting needs, and that they require flexibility to address such issues. NextEra argues that there is no convincing reason to limit the forecasting requirement to resources larger than 20 MW, and that the impact of small VERs on system variability is the same as resources greater than 20 MW. Midwest ISO Transmission Owners note that the Midwest ISO *pro forma* Generator Interconnection Agreement (GIA) applies to all interconnection customers, regardless of size, and as a result any reporting requirements adopted in the GIA should apply to generators with a capacity of less than 20 MW. California PUC asks that the Commission make clear that public utility transmission providers are not prohibited from requesting meteorological and operational data from small VERs. Environmental Defense Fund states that the Commission should host a technical conference to examine issues arising from requiring small generators to contribute information to support power production forecasting.

191. Some commenters address other aspects of the Commission's proposal to amend the *pro forma* LGIA. AWEA questions the Commission's preliminary conclusion that

[218] *E.g.*, Bonneville Power; Idaho Power.

the LGIA provides sufficient confidentiality protection for sensitive operational and meteorological data, stating that vendors providing forecasts to public utility transmission providers must not be allowed to use the data they collect for developing forecasts for the public utility transmission provider for any other purpose without express agreement. MidAmerican asks the Commission to clarify that there will not be any additional penalties for failure to provide accurate meteorological and operational data, other than the contractual remedies for breach already provided for in the *pro forma* LGIA. MidAmerican states that it recognizes that meteorological data are not always available if, for example, communication from a collecting device is interrupted. RenewElec recommends that the Commission set forth a data retention requirement in the new *pro forma* LGIA Article 8.4 that would require public utility transmission providers to maintain data collected from interconnection customers whose generating facilities are VERs for at least 10 years, facilitating follow-up studies to update power production forecasts.

f. Commission Determination

192. The Commission affirms the Proposed Rule and amends the *pro forma* LGIA to include a new Article 8.4 setting forth the reporting requirements adopted in this Final Rule. The Commission directs all public utility transmission providers to file a revised *pro forma* LGIA within 12 months of the effective date of this Final Rule reflecting the revisions adopted herein. As noted below, public utility transmission providers that have already implemented meteorological or forced outage reporting requirements may seek to

demonstrate, on compliance, that these existing business practices and market rules adequately satisfy the requirements of this Final Rule.

193. As set forth in the Proposed Rule, Article 8.4 of the *pro forma* LGIA did not state where the meteorological and forced outage data reporting requirements would be specified in an LGIA. The Commission agrees with Bonneville Power that it is appropriate to state reporting requirements for meteorological and forced outage data in Appendix C, Interconnection Details, as this will allow the requirements to be changed from time to time. The Commission therefore revises proposed Article 8.4 to specify that reporting requirements for meteorological and forced outage data would be set forth in Appendix C, Interconnection Details, of an LGIA. A transmission provider with an executed LGIA that seeks reporting of such data may negotiate revisions to Appendix C related to such reporting requirements with the interconnection customer. To the extent the parties mutually agree on changes to Appendix C, such changes to Appendix C need not be submitted to the Commission for review. If the parties are unable to reach agreement on proposed modifications to Appendix C, however, these parties may invoke their rights, as relevant, to modify the LGIA under sections 205 or 206 of the FPA, as appropriate, and pursuant to Article 30.11 of the LGIA.

194. The Commission disagrees with commenters suggesting that flexibility provided by business practices or market rules makes them a superior alternative for implementing the meteorological and forced outage reporting requirements adopted in this Final Rule. The Commission has sought to address public utility transmission providers' need for flexibility by clarifying that reporting requirements are to be set forth in Appendix C to

the LGIA, while also addressing interconnection customers' need for certainty in the obligations placed on them. The Commission appreciates that public utility transmission providers in some regions, including RTOs and ISOs, have already implemented meteorological or forced outage reporting under business practices and markets rules. Such public utility transmission providers may seek to demonstrate in their compliance filing how continued use of these existing business practices and market rules is adequate to satisfy the requirements of this Final Rule using the independent entity variation standard set forth in Order No. 2003, if relevant, or by demonstrating variations from the *pro forma* OATT are consistent with or superior to the requirements of this Final Rule.[219]

195. The Commission declines to modify existing LGIAs already in effect to include Article 8.4 of the *pro forma* LGIA as adopted in this Final Rule. The Commission acknowledges that, in some situations, there may be a sufficient amount of VERs already interconnected to the public utility transmission provider's system to make data from those resources useful or even necessary to properly implement power production forecasting. However, several considerations lead us to decline to modify every LGIA in effect on a generic basis. First the Commission believes retroactive changes to every LGIA in effect could be administratively burdensome to public utility transmission providers and interconnection customers, especially where the public utility transmission provider is not engaged in power production forecasting. Second, we note that nothing in

[219] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 9-10.

the *pro forma* LGIA precludes the parties to an LGIA from mutually agreeing to revise the requirements set forth in Appendix C to reflect the reporting of meteorological and forced outage data. Indeed, we note that Article 9.4 of the *pro forma* LGIA recognizes that Appendix C will be modified to reflect changes to the interconnection customer's requirements as they may change from time to time. Finally, if the parties are unable to agree to modifications of Appendix C, we note that pursuant to Article 30.11 of the *pro forma* LGIA, the transmission provider has the right to make a unilateral filing to the Commission proposing to modify an existing LGIA under section 205of the FPA.

196. For similar reasons, the Commission declines suggestions to implement data reporting requirements through the *pro forma* OATT instead of the *pro forma* LGIA or to include the requirements in the *pro forma* SGIA. The effect of relying on the *pro forma* OATT would be to impose the data reporting requirements adopted in this Final Rule on existing interconnection customers retroactively, including those with resources under 20 MW that are subject to the *pro forma* SGIA. Like data from existing resources, data from small resources may be useful or necessary for power production forecasting, yet the record in this proceeding does not demonstrate that the need for data from small resources is so great as to outweigh the potential burden that reporting requirements could impose on smaller resources. Just as the *pro forma* LGIA provides an opportunity for public utility transmission providers to mutually agree with interconnection customers regarding reporting requirements, nothing in the *pro forma* SGIA precludes the transmission provider from negotiating with the owners and operators of small VERs to update their SGIAs to provide for the reporting of meteorological and forced outage data

that are necessary for public utility transmission providers to employ power production forecasting. As with the *pro forma* LGIA, section 12.12 of the *pro forma* SGIA provides an opportunity for parties to an SGIA to bring any disagreement to the Commission for resolution.

197. In response to Midwest ISO Transmission Owners, the Commission notes that the extent to which a new LGIA is necessitated by a new Interconnection Request or Material Modification is governed by the *pro forma* LGIA and Commission precedent. To the extent a new LGIA is warranted, the VER interconnection customer would be subject to the relevant requirements of this Final Rule in effect at the time. Public utility transmission providers may seek to demonstrate in their compliance filings how continued use of existing tariffs, business practices and/or market rules is adequate to satisfy the requirements of this Final Rule using the independent entity variation standard set forth in Order No. 2003, if relevant, or by demonstrating variations from the *pro forma* OATT are consistent with or superior to the requirements of this Final Rule.[220]

198. With regard to AWEA's concern regarding the confidentiality of data, the Commission agrees that meteorological and forced outage data can be commercially sensitive, but concludes that the Article 22 of the *pro forma* LGIA provides adequate safeguards for reported data.[221] Any vendor providing forecasts to a public utility

[220] *See Id.* P 910.

[221] Article 22 of the *pro forma* LGIA defines Confidential Information to include, among other things, all information relating to a Party's technology, research and

(continued…)

transmission provider would be an agent of the public utility transmission provider subject to the confidentiality obligations of the *pro forma* LGIA. With regard to MidAmerican's concern regarding penalties for failure to provide accurate meteorological and forced outage data, the Commission notes that the extent to which penalties beyond those set forth in the *pro forma* LGIA might be appropriate for failing to satisfy data reporting requirements will necessarily depend on the facts and circumstances surrounding each instance of failed reporting. The Commission appreciates that unforeseen circumstances may impair an interconnection customer's ability to report data and that the impact of failed reporting may in many instances be *de minimus*. However, it would not be appropriate for the Commission to conclude generically that in no circumstance would additional penalties beyond those remedies set forth in the *pro forma* LGIA be appropriate for failure to comply with the data reporting requirements of an executed LGIA.

199. Finally, the Commission declines to impose special retention requirements for reported meteorological and forced outage data as requested by RenewElec. The time period over which a public utility transmission provider would need to retain meteorological or forced outage data will be a function of the type of power production forecasting being employed by the public utility transmission provider.

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development, business affairs, and pricing. Each party to an LGIA must hold in confidence and may not disclose to any person Confidential Information during the term of an LGIA and for a period of three years after the expiration or termination of an LGIA.

2. Definition of VER

a. Commission Proposal

200. In the Proposed Rule, the Commission sought to modify the *pro forma* LGIA to include a new definition for Variable Energy Resource in Article 1. The proposed definition identified a Variable Energy Resource as a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.[222] The Commission stated that it believed the proposed definition was consistent with NERC's characterization of variable generation.[223]

b. Comments

201. EEI supports the Commission's proposed definition without modification. California ISO supports the definition's focus on source of energy, but suggests that the phrase "by an energy source that" be replaced with "by a fuel source that." California ISO states that this change would make clear that the three conditions that follow pertain to the fuel source and not the nature of the facility itself.

202. Other commenters disagree with the focus on the source of energy, arguing that a VER should be defined by reference to its operating characteristics, including the ability

[222] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 64.

[223] *Id.* (citing NERC, *Accommodating High Levels of Variable Generation* 13-14 (2009), *available at* http://www.nerc.com/files/IVGTF_Report_041609.pdf).

to control output.[224] BrightSource states that this would allow for comparison between facilities with different fuel sources on standard operational and reliability time-frames and also avoid confusion about types of plants that combine renewable and conventional fuel sources, such as solar-gas hybrids. Joined by SEIA, BrightSource argues that a plant able to maintain a high level of operational control comes close to fulfilling the operational characteristics of a non-VER generation and should be treated as such for purposes of the Proposed Rule's requirements. NextEra agrees, stating that some resources can control the variability of their facility by adjusting output through feathering blades, self-curtailment, or similar measures. SEIA suggests that the Commission consider alternative criteria that could provide a distinction between VERs with a high level of control and VERs without such controls, such as if actual production can remain within some statistical measure of forecast accuracy during its operating hours. MidAmerican similarly requests that the Commission adopt a definition based on physical electrical generation output characteristics rather than input attributes such as fuel type, suggesting that whether energy sources qualify as "renewable" varies among states that have developed their own renewable resource regulations.

203. Several of these commenters question the applicability of the proposed definition to resources that use energy storage to control output. NaturEner provides a hypothetical example of a plant coupled with storage and asks that the Commission provide

[224] *E.g.*, AWEA; BrightSource; NaturEner; NextEra; RenewElec; SEIA.

clarification regarding the impact of such pairing on capacity reserve obligations. BrightSource asks the Commission to modify the definition to address how much storage results in a plant not being considered a VER for purposes of the Proposed Rule and any future rules. AWEA and NextEra request clarification that the proposed definition would not prevent VERs from electing to maintain VER status even if they use energy storage, other firming technologies, or otherwise have the ability to adjust output. RenewElec and SEIA argue that, regardless of the Commission's determination on the storage issue for VERs, such resources should not be exempt from reporting meteorological data to their public utility transmission provider. BrightSource and SEIA state that the applicability of the proposed definition is sufficiently important that the Commission should consider a technical conference on the issue.

204. Some commenters focus on the applicability of the proposed definition to particular types of resources, such as tidal, run-of-river hydro, conduit hydro, co-generation, or biomass.[225] Snohomish County PUD argues that, although such facilities would appear to satisfy the proposed definition, they should not be required to report the proposed data to public utility transmission providers because the data reporting would provide minimal benefit to grid operators while imposing a significant burden on these resources. Focusing on run-of-river hydro, Snohomish County PUD contends that whether such a facility is available at any given moment has no impact on the extent to

[225] *E.g.*, Grays Harbor PUD; NorthWestern; Pacific Gas & Electric; Snohomish County PUD.

which a sudden wind ramp might change production on the grid. NorthWestern and Pacific Gas & Electric agree, arguing that run-of-river hydro is much more predictable than wind or solar generation on a short-term basis and, as a result, there would be little benefit to collecting the meteorological data from such resources. In contrast, Entergy argues that the proposed definition and associated reporting requirements should be imposed on Qualifying Facilities to avoid gaps in forecasting and to allow public utility transmission providers to accommodate the variability that exists with both Qualifying Facilities and VERs.

205. Other commenters question the application of the proposed definition to solar resources.[226] California ISO explains that while solar thermal resources store solar thermal heat, they do not store solar irradiance itself, which is the energy source for the solar thermal facility. California ISO asks the Commission to clarify that a solar thermal facility would fall under the proposed definition. BrightSource contends that the storage and variability elements of the proposed definition appear to overlap functionally for a solar thermal plant, given that variability during the operating day could be controlled in many ways by the facility. BrightSource requests clarification regarding whether a VER would have to meet both or just one of these elements to fall within the definition.

206. ISO New England and NorthWestern offer opposing views on application of the proposed definition and associated reporting requirements on behind-the-meter

[226] *E.g.*, BrightSource; California ISO.

generation. ISO New England recommends that all distributed or behind-the-meter generation should be required to provide to the balancing and transmission entities in its area, at a minimum, specification of the technology and precise location of the installed resource so that a forecast of output can be developed on an aggregate scale to include in the balancing area forecast.

207. California State Water Project argues that its wholesale participating load resource also meets the definition of a VER. California State Water Project explains that participating load's primary purpose is not the provision of services to the grid, but rather water management, and that the load is subject to variability for reasons beyond California State Water Projects' control, such as competing environmental and water management requirements. Accordingly, California State Water Project requests that consideration be given to expanding the VERs definition to include large wholesale demand response resources that bid into markets not through a baseline mechanism, but rather on a basis comparable to generation.

208. ISO New England requests that the Commission afford flexibility for entities to use existing, superior definitions of VERs. The ISO New England Tariff already uses the term "Intermittent Power Resources" for wind, solar, run-of-river hydro and other renewable resources that do not have control over their net power output. As such, ISO New England requests that the Commission allow entities to use existing, superior approaches to the extent these are consistent with the objectives of the proposed reforms. ISO New England states that adding another term to its tariff could potentially lead to confusion, and therefore, argues that the region should be afforded the opportunity to

consider the existing terminology in the ISO New England Tariff, and determine whether any changes are warranted.

209. Bonneville Power states that, in light of its position that the *pro forma* LGIA provides transmission providers with the authority to update operational requirements for VERs, the Commission's proposed definition is unnecessary. However, Bonneville Power nonetheless states that it supports the inclusion of the proposed definition in all new VER interconnection agreements.

c. Commission Determination

210. The Commission adopts the Proposed Rule's definition of VER and, accordingly, amends Article 1 of the *pro forma* LGIA to include the following definition:

> Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

The Commission finds it necessary to define VERs in the *pro forma* LGIA in order to identify those resources that are required to provide to their public utility transmission provider meteorological and forced outage data necessary to enable the public utility transmission provider to develop and deploy power production forecasting. The Commission therefore declines to define VERs by their operating characteristics as suggested by BrightSource and MidAmerican or by reference to their lack of ability to store output, self-curtail production, or otherwise firm deliveries as suggested by BrightSource, NextEra and others. The Commission also declines to define VERs by

their fuel type as suggested by California ISO, because fuel type is an unduly restrictive subset of energy type.[227]

211. As noted elsewhere in this Final Rule, power production forecasting allows the public utility transmission provider to understand the characteristics of the input energy source for particular resources, to use those characteristics to predict how the resources will operate, and in turn to determine whether and to what degree the public utility transmission provider will need to reserve capacity to manage variability in generation output. Therefore, it is the variability of the energy source, not the operating characteristics of the plant or nature of output, that are critical to identifying the set of resources that must be subject to the meteorological and forced outage data requirements adopted above. Defining VERs by reference to operating characteristics or level of storage could limit the reporting of data in ways that undermines that ability of public utility transmission providers to engage in power production forecasting.

212. The Commission declines to establish an exemption to the data reporting requirements in this Final Rule for VERs utilizing energy storage or other firming technologies. Not only would this exemption inhibit the public utility transmission provider's capacity to predict how the VER resources will operate, but there is also insufficient evidence in this record to identify an objective threshold for exemption. The Commission clarifies that the purpose of this definition is to identify the resources that

[227] "Fuel" is defined as a material used to produce heat or power by burning. *See Merriam Webster,* http://www.Merriam-Webster.com, 2011. (November 4, 2011).

are required by this Final Rule to provide to their public utility transmission provider meteorological and forced outage data; the purpose is not, as suggested by NaturEner, to assign capacity reserve obligations or other charges. Nor does this definition supersede those created by other entities for purposes outside this rule, such as tax benefit purposes or renewable energy credits.

213. For similar reasons, the Commission declines to limit the VER definition in the *pro forma* LGIA to solar and wind resources so as to exclude run-of-river hydro, tidal, or other new and emerging VER technologies. Although the Commission anticipates that public utility transmission providers initially will engage in power production forecasting predominantly for wind and solar VERs, we leave to the public utility transmission providers to determine whether their individual systems necessitate power production forecasting for other types of VERs. Categorically excluding other types of resources would undermine the flexibility being provided in this Final Rule. At the same time, we decline to establish minimum reporting requirements for non-wind and non-solar VERs and leave to the public utility transmission providers and VERs to negotiate what data are necessary for developing and deploying power production forecasting for these resources, taking into account the size and configuration of the VER, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system

reliability in its area.[228] Because such requirements will vary system by system, it is not necessary to hold a technical conference to explore generic application of the VER definition as suggested by BrightSource and SEIA.

214. In response to California State Water Project, the Commission clarifies that VERs are not defined herein to include demand response resources. A demand response resource is not a device for the production of electricity and, therefore, would not fall within the VER definition adopted in the *pro forma* LGIA.[229] In response to ISO New England and NorthWestern, the definition potentially could apply to behind-the-meter generation, although such resources would only be subject to data reporting requirements adopted in this Final Rule to the extent they enter into a new LGIA or materially modify an existing LGIA after the effective date of this Final Rule.

215. ISO New England inquires as to the impact of the VER definition on other definitions in a public utility transmission provider's existing tariff. As noted above, public utility transmission providers that are RTOs or ISOs may seek to demonstrate in their compliance filing how existing tariffs, business practices or market rules are adequate to satisfy the requirements of this Final Rule using the independent entity

[228] If parties are unable to reach an agreement the public utility transmission provider may submit a filing requesting the data and demonstrating how it will be used for power production forecasting pursuant to section 205 of the FPA.

[229] A demand response resource may use behind-the-meter generation, potentially including VERs, to facilitate the provision of demand response. Such use, however, does not mean that such behind-the-meter generation is itself a demand response resource.

variation standard set forth in Order No. 2003, if relevant, or by demonstrating variations from the *pro forma* OATT are consistent with or superior to the requirements of this Final Rule.

216. With regard to Entergy's request that the Commission apply the proposed outage reporting requirement to Qualifying Facilities, we clarify that the data-reporting requirements under this rule apply to interconnection customers whose generating facilities are VERs as defined herein. Specifically, when an electric utility purchases an interconnected Qualifying Facility's total output, the relevant state authority exercises authority over the interconnection and the allocation of interconnection costs. But when an electric utility interconnecting with a Qualifying Facility does not purchase all of the Qualifying Facility's output and instead transmits the Qualifying Facility power in interstate commerce to another purchaser, the Commission exercises jurisdiction over the rates, terms, and conditions affecting or related to such service, such as interconnections.[230] Thus, for a Qualifying Facility that is a VER, when the interconnected Qualifying Facility is selling its total output to an electric utility, the meteorological and forced outage reporting requirements of this Final Rule do not apply. However, when an electric utility interconnecting with a Qualifying Facility does not

[230] Order No. 2003, FERC Stats. & Regs. ¶ 61,103 at P 813. The Commission regulations governing the exemptions enjoyed by Qualifying Facilities are codified at 18 C.F.R. Part 292, Subpart F (18 C.F.R. §§ 292.601-.602 (2011)). Limited exemptions from sections 205 and 206 of the FPA apply to certain sales of energy and capacity made by Qualifying Facilities. *See also Terra-Gen Dixie Valley, LLC*, 132 FERC ¶ 61,215, at PP 45-46 (2010).

purchase all of the Qualifying Facility's output and instead transmits the Qualifying Facility power in interstate commerce to another purchaser, the meteorological and forced outage reporting requirements of this Final Rule are applicable.

3. Data Sharing

a. Commission Proposal

217. In the Proposed Rule, the Commission sought comment on whether public utility transmission providers should be allowed or required to share VER-related data received from interconnection customers with other entities, like the source or sink balancing authority area for a transaction, or a government agency, such as NOAA, assuming confidentiality is protected.[231]

b. Comments

218. Clean Line and RenewElec state that operational and meteorological data should be made public to the maximum extent possible. RenewElec argues that there is a significant lack of operational data available to researchers in the area of VERs integration, and asks that the Commission require that: (1) VER data be made public within six months of the date on which such data is submitted by the interconnection customer, and (2) operational data, including VER data, used by transmission providers to develop VER power production forecasting be made available to interested parties.

[231] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 63.

219. While generally stating support for the sharing of data, some commenters raise confidentiality concerns and point out the commercially-sensitive nature of data subject to the reporting requirements contemplated in the Proposed Rule.[232] For example, Southern California Edison supports sharing VER-related data for the purposes of increasing forecasting accuracy, as long as the data are not proprietary data that the public utility transmission provider is prohibited from disclosing to other parties. Bonneville Power and a few others contend that while sharing data from individual VERs poses confidentially issues, sharing aggregate VER data does not pose the same problems.[233] Sunflower and Mid-Kansas state that, within RTOs, the stakeholders should decide which entities should be provided VER data. Western Farmers request that the Commission confirm that, where the transmission provider is not the balancing authority, the data should also be provided to the relevant balancing authority. NextEra and AWEA only support sharing data with other balancing authorities when the resource is being dynamically scheduled or dispatched into that balancing authority. Bonneville Power suggests that, at a minimum, the Commission should allow public utility transmission providers and balancing authorities to share aggregate forecasts for VER output with all parties to an e-tag.

[232] *E.g.*, CGC; California PUC; EEI; NextEra; PJM; SMUD; ISO New England.

[233] *E.g.*, Bonneville Power; California ISO; Exelon; SEIA.

220. Several commenters support sharing VER-related meteorological data with NOAA, including having the data incorporated into foundational models run by NOAA.[234] Commenters, including NOAA, request that the Commission require VERs to submit meteorological data to NOAA for the purpose of improving atmospheric characterization and forecast accuracy.[235] In response to confidentiality concerns, NOAA states that private sector proprietary data can be protected from distribution and anonymized in the analysis and generation of forecasts, which would then allow improved predictions to be available for the private sector to incorporate into power production forecasts.

c. Commission Determination

221. The Commission declines to expand the Proposed Rule to require public utility transmission providers to share VER related data with other entities such as a balancing authority area or NOAA. However, the Commission strongly encourages the voluntary sharing of data where appropriate. Many commenters assert that significant benefits might flow from VERs sharing data with entities such as a balancing authority area or NOAA. The Commission finds that VERs are in the best position to negotiate what data are needed and to weigh the benefits that may be expected as a result of providing such data. In addition, negotiating directly with other entities will allow VERs to ensure that

[234] *E.g.*, AWEA; Bonneville Power; CGC; Iberdrola; ISO New England; MidAmerican; NaturEner; NOAA.

[235] *E.g.*, Bonneville Power; Iberdrola; NOAA.

adequate confidentiality protections are in place for information that they may consider to be commercially sensitive or otherwise confidential. If helpful to industry participants, the Commission will consider making staff available to work through issues and, if appropriate, take additional steps to facilitate the voluntary sharing of information.

4. Cost Recovery

a. Commission Proposal

222. In the Proposed Rule, the Commission refrained from proposing a single method of cost recovery for the development and implementation of power production forecasts. Instead, the Commission sought comments on how public utility transmission providers may recover costs incurred to develop and deploy power production forecasting tools.[236]

b. Comments

223. Among those seeking flexibility, AWEA states that the Commission is correct to not propose a single uniform method for allocating these costs, and instead should defer to public utility transmission providers and others to determine how these costs should be allocated. Several commenters request that the Final Rule provide flexibility to public utility transmission providers and/or regions to propose cost recovery approaches.[237] For example, EEI contends that generally no interconnected resource should be exempt from the responsibility for costs that it causes to be incurred, but asks that the Commission not

[236] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 57.

[237] *E.g.*, AWEA; California PUC; Duke; ISO New England; MidAmerican; Pacific Gas & Electric.

mandate how costs should be allocated at this time, allowing regions to develop appropriate cost-recovery solutions.

224. Some commenters recommend that the cost of forecasting be spread among all transmission customers.[238] Independent Power Producers Coalition-West argues that forecasting tools will ultimately reduce costs to utilities and generators, and will ultimately be a small cost of doing business in a world where forecasting can and should be a constant element of the power scheduling process. Public Interest Organizations state that the costs of centralized forecasting infrastructure should be spread across all those who benefit from the improved accuracy and decreased costs, provided those costs are demonstrated to be just and reasonable. Joined by NextEra, Public Interest Organizations argue that the broad benefits of forecasting justify the sharing of related costs across the transmission system(s) that benefit.

225. Iberdrola contends that there is no difference in the costs incurred to develop and deploy power production forecasting tools and the costs of developing and implementing other market design features. Iberdrola states that these types of costs typically are not directly assigned to one set of market participants, but are spread to all users of the transmission system because they benefit all users of the system. Iberdrola states that the costs incurred to develop and deploy power production forecasting tools should similarly be spread to all system users.

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[238] *E.g.*, Iberdrola; Independent Power Producers Coalition-West; NextEra; Public Interest Organizations; Exelon.

226. Exelon recommends recovering the cost of forecasting within administrative charges, the approach taken by PJM and ERCOT. Exelon provides an example of ERCOT's handling of the costs: the cost of developing the ramp probability tool was a one-time investment that was recovered by the transmission provider in uplift to the market. The ongoing cost of using the tool is also spread across the market. Exelon states that this approach avoids the problem of free-ridership by future market participants that would occur if these costs were recovered solely from existing market participants.

227. Other commenters argue either that the VERs, or the beneficiaries of VERs, should be financially responsible for the costs of forecasting.[239] These commenters generally contend that public utility transmission providers should be able to recover the costs incurred to develop and deploy power production forecasting by imposing a fee or rate upon the VERs causing the costs to be incurred. For example, NRECA argues that non-VER transmission customers are neither causing nor benefiting from the enhancements to power production forecasting and, therefore, should not be forced to subsidize its costs, citing *Northern States Power Company*.[240] Montana PSC suggests that all VERs of 1 MW or greater should be responsible for power production forecasting

[239] *E.g.*, Bonneville Power; ELCON; Large Public Power Counci; MidAmerican; Midwest ISO Transmission Owners; Montana PSC; NorthWestern; NRECA; Oregon & New Mexico PUC; PNW Parties; SMUD; Southern California Edison; Tacoma Power.

[240] NRECA (citing *N. States Power Co.*, 64 FERC ¶ 61,324, at P 63,379 (1993)).

costs. Pacific Gas & Electric notes the approach taken in the California ISO's Participating Intermittent Resources Program, in which the California ISO charges a fee to VERs to recover costs to develop and deploy power production forecasts.

228. ELCON and Tacoma Power argue that any resource, whether or not it is a VER, should be held fully accountable for the costs it causes the transmission provider to incur on its behalf. ELCON argues that meteorological forecasting is simply a cost of doing business for wind energy, just as a nuclear power plant must pay for storage of spent fuel. ELCON argues that these costs should not be recovered in uplift charges in regions served by ISOs or RTOs, or allocated to non-customers of VER transactions.

229. SEIA recommends that the Commission examine whether there may be market entities that would consider contributing to the costs of the forecast service providers in the non-organized market regions, e.g., power traders may be willing to pay for the aggregate day-ahead and hour-ahead forecasts across such regions. SEIA states that these revenues could be used to develop aggregated forecasts for more geographical areas within a region that could further reduce integration costs.

230. Duke argues that the Commission should allow public utility transmission providers to update any costs associated with the Proposed Rule's reporting and power production forecasting requirements without triggering a general rate case. Duke suggests that one possible option would be through a formula rate that is updated periodically for changes in costs related to forecasting and data reporting.

231. Finally, some commenters request that the Commission recognize that the costs of centralized forecasting go beyond the expense of forecasting tools.[241] These additional costs include gathering data, installing and operating onsite telemetry, equipment to record meteorological data, and data management. Southern California Edison points out that data and telemetry are only as good as the personnel assessing the information.

c. Commission Determination

232. The Commission finds that it is not necessary to prescribe a single method of cost recovery for developing and implementing power production forecasting, as it is likely that not all public utility transmission providers will develop power production forecasting, given regional differences in the types and penetration of VERs. Moreover, the record in this proceeding demonstrates that the circumstances under which a public utility transmission provider may decide to develop and deploy power production forecasting may vary by system. In some instances, public utility transmission providers might develop and employ power production forecasting in order to manage more effectively the commitment of reserves associated with the provision of generator regulation service, as discussed in other sections of this Final Rule. In other circumstances, public utility transmission providers might develop and employ power production forecasting to manage reserve costs recovered under other ancillary services. In addition, public utility transmission providers may seek to recover costs associated

[241] *E.g.*, Pacific Gas & Electric; Southern California Edison; NorthWestern.

with power production forecasting in different ways, as cost recovery may be sought via a general rate case, formula rate, or other mechanism. Given the myriad of factors that may be relevant to the allocation and recovery of such costs, the Commission finds it appropriate to evaluate requests for the recovery of costs incurred to develop and deploy power production forecasts on a case-by-case basis consistent with FPA section 205 and Commission precedent.

C. Generator Regulation Service-Capacity

233. In the Proposed Rule, the Commission preliminarily found that clarifying the manner by which public utility transmission providers may recover the costs associated with fulfilling their obligation to offer generator regulation service would remove barriers to the integration of VERs by eliminating public utility transmission providers' uncertainty regarding cost recovery.[242] As discussed below, the Commission concludes that adoption of this reform could inhibit the flexibility to design capacity services that align with the operational practices or needs of a particular public utility transmission provider. The Commission therefore declines to adopt a generic Schedule 10 for generation regulation service this reform and instead provides guidance to assist public utility transmission providers and their customers in the development and evaluation of proposals related to recovering the costs of regulation reserves associated with VER integration.

[242] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 87.

1. Schedule 10-Generator Regulation and Frequency Response Service

234. In the Proposed Rule, the Commission proposed incorporating into the *pro forma* OATT a new ancillary service schedule for Generator Regulation and Frequency Response Service. The Commission introduced this proposal with a review of the adoption in Order Nos. 888[243] and 890[244] of ancillary services schedules for Regulation and Frequency Response Service (regulation service), energy imbalance service, and generator imbalance service.[245] The Commission repeats that introduction here for background.

235. Regulation service, offered under Schedule 3 of the *pro forma* OATT, provides the capacity reserve necessary for the continuous balancing of resources (generation and interchange) with load to maintain a scheduled interconnection frequency of 60 cycles per second (60 Hz).[246] In Order No. 888, the Commission required public utility transmission providers to offer regulation service for transmission service within or into the public utility transmission provider's balancing authority area to serve load in that area.[247] However, the Commission did not require public utility transmission providers

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[243] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,703-04.

[244] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 627.

[245] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at PP 66-71.

[246] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,707-08.

[247] *Id.* at 31,717.

to offer regulation service for transmission service out of or through the public utility transmission provider's balancing authority area to serve load in another balancing authority area.[248]

236. Energy imbalance service, offered under Schedule 4 of the *pro forma* OATT, accounts for hourly energy deviations between a transmission customer's scheduled delivery of energy and the actual energy used to serve load.[249] In Order No. 888, the Commission required public utility transmission providers to offer energy imbalance service for transmission service within and into the public utility transmission provider's balancing authority area to serve load in that area.[250] Like regulation service, the Commission did not require public utility transmission providers to offer energy imbalance service for transmission service being used to serve load in another balancing authority area.

237. Regulation service and energy imbalance service, while different in function, are complementary services through which public utility transmission providers maintain their systems' balance and recover both the capacity (regulation service) and energy (energy imbalance service) costs of doing so from transmission customers serving load on their systems. At the time of Order No. 888, the Commission believed that it was

[248] *Id.*

[249] *Id.* at 31,708.

[250] *Id.* at 31,717.

reasonable to provide only standardized ancillary service schedules for transmission used to service load because load (rather than generation) exhibited the greatest amount of variability.[251] The Commission noted that generators should be able to deliver scheduled hourly energy with precision and that the requirements for generators to meet their schedules should be contained in interconnection agreements.

238. In Order No. 890, the Commission noted that the existing energy imbalance charges were the subject of significant concern and confusion in the industry.[252] The Commission expressed concern about the variety of different methodologies used for determining imbalance charges and whether the level of the charges provided the proper incentive to keep schedules accurate without being excessive.[253] Such concerns led the Commission to revise existing *pro forma* energy imbalance service provisions and require public utility transmission providers to offer a new service, generator imbalance service, to account for hourly energy deviations between a transmission customer's scheduled delivery of energy from a generator and the amount of energy actually

[251] In 1996, when Order No. 888 was developed and issued, wind generation was not a significant energy source, with a total capacity of approximately 1,698 MW. *See Imbalance Provisions for Intermittent Resources; Assessing the State of Wind Energy in Wholesale Electricity Markets*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,581, at P 7 (2005).

[252] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 634.

[253] *Id.*

generated.[254] The Commission found that formalizing generator imbalance provisions in the *pro forma* OATT would standardize future treatment of such imbalances, thereby lessening the potential for undue discrimination, increasing transparency, and reducing confusion in the industry that resulted from the then current plethora of different approaches.

239. While the *pro forma* generator imbalance service provides a mechanism for public utility transmission providers to recover the cost of providing the *energy* needed to manage hourly generator imbalances, it does not provide a mechanism for public utility transmission providers to recover the costs of holding reserve *capacity* associated with providing generator imbalance energy.[255] Although the Commission in Order No. 890 did not create a new rate schedule to expressly account for these capacity costs, it acknowledged the likelihood that such costs would be incurred in connection with the provision of generator imbalance service.[256] Accordingly, the Commission provided a mechanism by which public utility transmission providers could recover these costs, explaining that "[t]o the extent a [public utility] transmission provider wishes to recover costs of additional regulation reserves associated with providing imbalance service, it

[254] *Id.* P 663.

[255] *Id.* P 689 ("The Commission concludes that excluding additional regulation costs as a general matter is appropriate because much of those costs would be demand costs.").

[256] *Id.* P 690.

must do so via a separate FPA section 205 filing demonstrating that these costs were incurred correcting or accommodating a particular entity's imbalances."[257] In Order No. 890-A, the Commission clarified that public utility transmission providers may propose to assess regulation charges to generators selling in the balancing authority area, as well as generators selling outside the balancing authority area, and that the Commission will consider such proposals on a case-by-case basis.[258]

a. Commission Proposal

240. In the Proposed Rule, the Commission sought to add a new rate schedule to the *pro forma* OATT that complements the generator imbalance service provided under Schedule 9 of the *pro forma* OATT. The Commission noted that, in order to meet their obligations to offer generator imbalance service under Schedule 9, public utility transmission providers must hold unloaded resources in reserve to respond to moment-to-moment variations attributable to generation. The Proposed Rule recognized this *de facto* obligation and proposed to establish a generic rate schedule (Schedule 10 - Generator Regulation and Frequency Response Service) through which public utility transmission providers may recover the costs of providing this service. The Commission preliminarily found that clarifying the manner by which public utility transmission providers may recover the costs associated with fulfilling their obligation to offer this service will

[257] *Id.* at P 689 & n.401 (referring to costs associated with capacity used to provide generator imbalance service that otherwise are not recovered through Schedule 3).

[258] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 313.

remove barriers to the integration of VERs by eliminating public utility transmission providers' uncertainty regarding cost recovery.[259]

241. In the Proposed Rule, the Commission stated that Schedule 10 is modeled on Schedule 3 - Regulation and Frequency Response Service of the *pro forma* OATT. Where Schedule 3 allows public utility transmission providers to recover the costs of regulation reserves associated with variability of load within its balancing authority area, proposed Schedule 10 would provide a mechanism through which public utility transmission providers can recover the costs of providing regulation reserves associated with the variability of generation resources both when they are serving load within the public utility transmission provider's balancing authority area and when they are exporting to load in other balancing authority areas.[260]

242. The Commission proposed that, consistent with Order No. 890, public utility transmission providers would not be permitted to charge transmission customers for regulation reserves under both Schedule 3 and Schedule 10 for the same transaction.[261] The Commission emphasized that in establishing Schedule 10, it was not changing the

[259] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 87.

[260] *Id.* P 88.

[261] *Id.* P 89 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690 (requiring transmission providers to demonstrate that any proposals to recover capacity costs associated with Generator Imbalance Service do not lead to double recovery); *Entergy Serv., Inc.*, 120 FERC ¶ 61,042, at PP 62-66 (2007); *Sierra Pac. Res. Operating Cos.*, 125 FERC ¶ 61,026 (2008); *Westar Energy Inc.*, 130 FERC ¶ 61,215, at P 4 (2010)).

nature of the services that a public utility transmission provider must offer its transmission customers. The Commission stated that nothing in the Proposed Rule would affect the manner in which balancing authorities are required to maintain balanced systems that are operated in a safe and reliable fashion, consistent with NERC Reliability Standards. The Commission explained that it simply proposed to establish a generic cost recovery mechanism for a service that public utility transmission providers already are obligated to offer customers taking transmission service within their balancing authority area.[262]

243. In the Proposed Rule, the Commission explained that public utility transmission providers are not permitted to disclaim the obligation to offer to provide transmission customers with the capacity reserves associated with the provision of generator imbalance service.[263] Therefore, the Commission proposed that, under Schedule 10, a public utility transmission provider must offer generator regulation service to the extent it is physically feasible to do so from its resources or from resources available to it, to transmission customers using transmission service to deliver energy from a generator located within the public utility transmission provider's balancing authority area.[264]

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[262] *Id.* P 91.

[263] *Id.* P 84 (citing *NorthWestern, Corp.*, 129 FERC ¶ 61,116, at P 27 (2009)).

[264] *Id.* P 89.

b. Comments

i. Proposed Schedule 10

244. Although several commenters support the Commission's proposal to establish a schedule for the recovery of capacity costs for regulation reserves, much of that support is tempered by concern about the scope and design of proposed Schedule 10, as well as the flexibility afforded public utility transmission providers to design services relevant to recover all costs associated with the integration of VERs under proposed Schedule 10.[265] For example, while EEI indicates that it supports the establishment of a cost recovery mechanism for regulation reserves from transmission customers as promoting rate certainty and transparency, it also cautions the Commission that the proposal may unduly condition cost recovery and may not encompass all cost incurred by the transmission provider. While Independent Power Producers Coalition–West supports the concept of a generic generator imbalance tariff to bring certainty to disparate tariffs that must now be negotiated in WECC, it contends that the Commission should require utilities to revise operating agreements, business practices or other procedures such that independently owned generator resources are available to balancing authorities in the WECC to reduce generator imbalance costs for VERs. Large Public Power Council supports the new Schedule 10 provided it is implemented in a way that allows transmission providers to receive full compensation for providing the service.

[265] CMUA at 10-11; EEI at 25-33; Midwest ISO at 14; NRECA at 23-24; Organization of Midwest ISO States at 8-9.

245. NRECA indicates that it also supports the cost recovery proposal embodied in proposed Schedule 10; however, it expresses concern that Schedule 10 should not be limited to just the recovery of regulation costs, and should instead be expanded to allow public utility transmission providers the opportunity to demonstrate that additional VER integration costs should be recovered through individual Schedule 10s. According to NRECA, such costs may include the following: (1) intra-hour schedule implementation costs; (2) power production forecasting implementation costs; or (3) other various costs such as load-following service, ramping costs, out-of-merit dispatch costs, and additional spinning and supplemental reserves, among other things.

246. Public Power Council and Puget express similar concerns that the proposed Schedule 10 would not allow for full recovery of all costs of balancing and integrating VERs. According to Public Power Council, Schedule 3 recovers the costs of balancing reserves deployed for frequency and regulation control, which in turn leads Schedule 10 to only recover the costs of regulation (capacity following near instantaneous changes in generation) but not the costs arising from either load following capacity (capacity used minute-to-minute over approximately a 10-minute period) or capacity needed to make up a variable generator's schedule error for the scheduling period. Public Power Council also argues that Schedule 10 charges should include the costs of power production forecasting systems as these would not be needed but for the integration of variable generation. The PNW Parties agree and suggest that Schedule 10 should be expanded further to allow for the recovery of all costs incurred by the public utility transmission provider in providing regulating reserves that are not recoverable through the generation

imbalance rate, including but not limited to, extra energy costs and operation and maintenance costs.

247. Southern states that the capacity required to provide generator imbalance service or otherwise respond to operational challenges presented by substantial swings in output from generators (particularly VERs) may mostly be conceptualized as providing a "regulation" service, but it should be understood that some public utility transmission providers may also incur additional costs that may implicate other ancillary services, such as reactive power and load following, if not contingency response. Southern asserts that the Commission should not categorically foreclose or limit in advance the right of public utility transmission providers under section 205 to file tariffs or tariff amendments on a case-by-case basis to recover any and all additional reasonable costs specific to VER-related regulation reserve requirements. Southern requests that the Commission confirm that the invitation in Order No. 890 for public utility transmission providers to file rate schedules and amendments to address costs of generator imbalances on a case-by-case basis remains open.

248. Public Interest Organizations contend that it may be unjust and unreasonable to charge VERs regulation rates for capacity requirements that can be addressed by less expensive ancillary services. Public Interest Organizations state that the Commission could address this problem either by reforming Schedule 10 into a slower service akin to load-following or non-spinning reserves, or by clarifying that Schedule 10 is designed to compensate only for the moment-to-moment balancing associated with generation

variability, and not for VER variability that affects the system beyond the balancing timeframe.

249. AWEA suggests that the Commission focus on such longer-term variability, requesting that the Commission reformulate proposed Schedule 10 as a system non-spinning service to accommodate the aggregate system variability that is not accommodated through other ancillary services. AWEA states that this type of service would benefit all users of the system by providing inexpensive reserves to accommodate all types of gradual variability on the power system, including changes driven by inaccurate load forecasts, changes in demand driven by large electricity users, as well as aggregate changes of many small users. AWEA notes that wind and solar exhibit little variability over the regulation time period while variability over the course of an hour can be more significant. AWEA argues that a system non-spinning service would be well-suited for accommodating the incremental increase in system variability caused by the addition of such resources.

250. Similarly, Iberdrola recommends the Commission structure Schedule 10 as a following reserves service rather than regulation reserve, arguing that the rate of change associated with wind ramps is not instantaneous but rather occurs over longer time periods within the hour and often for multiple hours. To the extent that the Commission does not reformulate Schedule 10 in this way, Iberdrola requests that the Commission convene a technical conference that focuses on the ancillary services needed to support VERs. NextEra agrees that the Commission should convene a technical conference to

address what kind of ancillary services should be developed to complement the growth of VERs, among other things.

251. Duke suggests that the Commission should unbundle regulation and frequency response service into separate ancillary service schedules. In support, Duke points to such industry activities as NERC developing a revision to Frequency Response Reliability Standard BAL-003-0, which will prescribe specific amounts of frequency response that each balancing authority must procure; the Commission report prepared by the Lawrence Berkeley National Laboratory, which discusses operational characteristics and distinctions of primary and secondary frequency control reserves (Docket No. AD11-8-000); and the Commission's Notice of Proposed Rulemaking in Docket Nos. RM11-7-000 and AD10-11-000, which also distinguishes frequency response from regulation.

252. American Clean Skies argues that the Proposed Rule should require RTOs to offer additional ancillary services, such as load following (on a minute-to-minute basis), reactive power and other comparable backup capabilities. Coalition for Green Capital similarly asks the Commission to encourage the development of power and ancillary services products that match the technical and commercial capabilities of VERs to allow VERs to integrate into the bulk power grid at rates and on terms and conditions that are just and reasonable and not unduly discriminatory or preferential. Independent Energy Producers assert that, while it is critical that ancillary service products be identified and developed to permit VERs to be integrated, it is equally critical that the necessary compensation measures be developed to ensure that dispatchable generation is available

when and where it is needed to support the ancillary services products, particularly within the California ISO market.

253. With regard to charging transmission customers under both Schedule 3 and the proposed Schedule 10, Bonneville Power agrees with the Commission's decision in Order No. 890 regarding the potential for double recovery if energy settlement charges (under Schedules 4 and 9 of the OATT) are imposed on both the generator and load when they reside in the same balancing authority, but argues that there are significant differences between energy settlement charges and capacity charges recovered under Schedule 3 and Proposed Schedule 10. Bonneville Power states that the public utility transmission provider must maintain balancing reserve capacity for movement of both the load and the generators located in its balancing authority area because the deviations from schedule for the load and generation move independently from one another, and that the transmission provider should be allowed to recover costs for capacity it is providing to both generation and load.

254. Duke similarly argues that the Commission should allow the public utility transmission provider to recover both Schedule 3 and 10 costs if both services are utilized by the transmission customer. Duke contends that it is appropriate in some circumstances to charge a load for Schedule 3, and a generator for Schedule 10, even if they are owned by the same party. According to Duke, unless the generator is coupled to the load by an energy management system (i.e., the generator is controlling to the load), or the generator is dynamically serving a load (i.e., where its output can be controlled to match the load it serves), a public utility transmission provider should be permitted to charge for both

Schedule 3 and Schedule 10 as they are two different services which can be provided at the same time (e.g., where a load serving entity owns load within a control area, as well as a generator).

255. Finally, several commenters contend that Schedule 10 is not necessary in organized markets.[266] PJM interprets Schedule 10 as optional and seeks clarification that this interpretation is correct. Sunflower and Mid-Kansas submit that the SPP market rules already are consistent with or superior to the *pro forma* OATT as the Commission proposes to amend it in this Proposed Rule and believes it is highly likely that all of the other RTOs' rules are also superior to what has been proposed. Clean Line contends that the potential of double recovery exists for generators receiving compensated through organized market mechanisms. AWEA contends that the Commission should clarify that the creation of Schedule 10 service should apply only in areas of the country that do not have functioning ancillary services markets. Likewise, Iberdrola explains that a Schedule 10-type product is not necessary in organized markets, as most organized markets balance the system's energy and reserve requirements through use of simultaneously co-optimized Security Constrained Unit Commitment and Security Constrained Economic Dispatch algorithms that clear and dispatch energy and reserves.

[266] *E.g.*, AWEA; California ISO; Iberdrola; ISO New England, New York ISO; Sunflower and Mid-Kansas.

ii. Obligation to Offer Generator Regulation Service

256. Several commenters seek clarification regarding the extent to which the public utility transmission provider must provide generator regulation service. NaturEner states that public utility transmission providers should not be able to avoid providing regulating reserves based upon claims that they themselves do not own generation in sufficient amounts to supply the service. Xtreme Power asks that the Commission make clear that, in the event that a public utility transmission provider's existing resources are not adequate to meet the obligation to provide generator regulation service and new resources are needed to accommodate additional variability, the public utility transmission provider is obligated to procure a sufficient quantity of the appropriate resources.

257. Grant PUD asks whether a public utility transmission provider must procure additional regulation resources if the demand for these services exceeds the contractual and owned resources available to the public utility transmission provider that can provide regulation service at the time of the request for service. NorthWestern requests that the Commission clarify that the phrase "or from resources available to it" refers to acquisition of generator regulation service from third parties and is not intended to mean that, if the utility does not have access to its own resource or resources from the market, the utility must build generation for Schedule 10 service. Independent Power Producers Coalition–West states that transmission providers should not be permitted to charge VERs for generator imbalance services unless they provide VERs with the capability to obtain those services from third parties on a non-discriminatory basis. If a public utility transmission provider does not have access to its own resources or resources from the

market and chooses to build new generation to offer Schedule 10 service, EEI asks the Commission to clarify that these costs can be recovered from the resources that trigger the need to build. EEI also states that the language "or from resources available to it" could be read to require the public utility transmission provider to violate reliability standards by using resources set aside for contingency reserves to support generation regulation service.[267] EEI requests that the Commission clarify the statement as follows: "a public utility transmission provider must offer generator regulation service; to the extent it is physically feasible to do so from its existing resources or from resources currently available to it, without violating applicable reliability standards."[268]

258. Puget asks that the Commission clarify that public utility transmission providers are only required to provide Schedule 10 service within a defined confidence interval commensurate with the public utility transmission provider's level of regulation capacity set aside for cost recovery under the Schedule 10. If those resources' capabilities are exceeded or if system conditions otherwise warrant, Puget suggests that the public utility transmission provider should retain the right to curtail generation production or export schedules to preserve reliability. Public Power Council and Bonneville Power also question whether the obligation to provide generator regulation service is unlimited, suggesting that such service could require firming of every generation delivery, which

[267] EEI at 32.

[268] *Id.*.

would be extremely expensive. Bonneville Power contends that the source balancing authority should have the ability to offer a base level quantity of balancing reserve capacity and should have the right to use operational tools to limit the deployment of reserves to that quantity. In support, Bonneville Power explains that it has developed Dispatcher Standing Order 216 (DSO 216) to require reductions in wind generation or changes to wind generators' transmission schedules when the schedule error of the wind fleet exhausts the total amount of balancing reserve capacity that Bonneville Power has made available for wind and load.

259. Bonneville Power states that it is currently providing enough balancing reserve capacity to meet the needs of the wind fleet in its balancing authority during 99.5 percent of the forecast VER variability events. Bonneville Power describes the remaining 0.5 percent as representing the most extreme variability in VER generation (i.e., "tail events"). Because of the substantial wind generation exports from Bonneville Power's balancing authority area, Bonneville Power explains that it needs a mechanism to "clip the tails" of wind ramps when they exhaust the total amount of balancing reserve capacity that Bonneville Power makes available for wind and load. Bonneville Power states that DSO 216 allows it to establish the amount of balancing reserve capacity that will be deployed and, because there is a set limit, it is able to quantify its obligation and risks for rate setting, system planning, and reliability purposes. Bonneville Power contends that a requirement to maintain balancing reserve capacity at all times to manage tail events would be significantly expensive.

260. Bonneville Power also asks the Commission to clarify that the public utility transmission provider is required to offer to provide Schedule 10 service only to the extent it can do so without harming system reliability or risking non-compliance with state and Federal law and other non-power requirements that affect system operations. Snohomish County PUD and Grays Harbor PUD similarly ask the Commission to clarify that Bonneville Power should not be required to offer capacity from the Federal System to meet demand for services under Schedule 10 where that capacity is not available due to statutory and regulatory obligations that limit the availability of the Federal System's capacity. Grays Harbor PUD adds that the Commission should make clear that, during periods when Bonneville Power's system is limited by statutory and regulatory constrains, it is not "physically feasible" for Bonneville Power to use that capacity to support integration of VERs and, therefore, during those periods is exempt from requirements to do so. Bonneville Power further requests that the Commission clarify that the public utility transmission provider is obligated to provide generator regulation service pursuant to Schedule 10 and generator imbalance service pursuant to Schedule 9 only to the extent that balancing reserve capacity is made available pursuant to Schedule 10. In addition, Bonneville Power suggests that the Commission should address the pricing policy articulated in the *Avista* line of cases, which restricts public utility transmission providers that are not in organized markets to recovering cost-based rates for ancillary services, to ensure public utility transmission providers have the ability to

obtain the necessary balancing reserve capacity.[269] Tres Amigas concurs with Bonneville Power and suggests that the Commission alter its approach so that these services can be bought and sold competitively outside of organized RTO markets as they are in most RTOs.

iii. Self-supply of Generator Regulation Service

261. First Wind asks the Commission to clarify that Schedule 10 charges would be imposed on VERs only to the degree they take transmission service or otherwise elect to take Schedule 10 service. AEP contends that the Proposed Rule contains a loophole in that purchasers of VER energy outside of the resource's native balancing authority's footprint would be able to avoid any ancillary service charges caused by their purchase and transport of energy. Other commenters discuss how the balancing authority into which generation is dynamically scheduled would be compensated for providing regulation service.[270] These commenters contend that because the sink balancing authority is providing the regulation service for that generator in these situations, it should be clear in Schedule 10 that the sink balancing authority will be paid for providing that service.

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[269] Bonneville Power (referencing *Avista Corp.*, 87 FERC ¶ 61,223 (1999); *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, Order No. 697, 119 FERC ¶ 61,295 (2007) (Order No. 697)).

[270] *E.g.*, Duke; EEI; Exelon.

262. Commenters address the option for transmission customers to self-supply generator regulation service. Bonneville Power states that it recognizes that VERs may find it economical to self-supply balancing reserve capacity to provide balancing service and asks the Commission to clarify in Schedule 10 that a customer electing to self-supply is subject to the public utility transmission provider's requirements for Schedule 10 service and the transmission provider's reliability and operational protocols, including any transmission curtailments and generation limitations in the event the self-supplying VER fails to meet the transmission provider's standards. Powerex agrees that the public utility transmission provider should have discretion to decide whether a method of self-supply is acceptable but argues that the public utility transmission provider should be required to describe what it considers to be acceptable comparable arrangements in posted business practices.

263. Xtreme Power similarly contends that, in order for self-supply or third-party procurement of generator regulation service to be a viable option, the public utility transmission provider must specify how a customer's generator regulation service requirements are determined and how the requirements may be satisfied through self-supply or third-party procurement. NaturEner contends that the self-supply provision should be administered on a flexible basis and this could include use of self-curtailment, carrying of a portion of the regulating reserve capacity on a dynamic basis, and carrying of a varying level of regulating reserves because a constant level is not necessary. Independent Power Producers Coalition–West argues that public utility transmission providers should only be permitted to charge VERs for generator imbalance services if

they provide VERs with the capability to obtain those services from third parties on a non-discriminatory basis.

264. Beacon Power indicates that entities subject to Schedule 10 should be allowed to work with public utility transmission providers in non-RTO/ISO markets to determine different volumes of self-supplied regulation reserve capacity required based on the ramp-rate capability of its regulation resource(s). CESA agrees that, if a transmission customer subject to the Schedule 10 chooses to self-supply its regulation reserve capacity, the amount of capacity self-supplied should account for the fact that a MW of reserve capacity from a fast-ramping resource provides more regulation value to the grid per MW than a slow-ramping resource. NEMA indicates that some resources that provide generator regulation service, such as batteries and flywheels, can dampen variations much more quickly than can traditional generators. Therefore, NEMA contends that the generator regulation service requirements should be based on the amount of generator regulation service actually *provided*, rather than solely the *capacity* of regulation service. A123 recommends that the Commission clarify the phrase "alternative comparable arrangements" to include resources that may differ in MW capacity but supply equivalent or superior regulation performance when compared to the public utility transmission provider's default service.

265. Powerex asks that the Commission confirm that self-supply includes the ability of the transmission customer to self-supply by purchasing regulation reserve capacity from

third parties.[271] Powerex states that it could be helpful for the Commission to provide guidance on what should qualify as an "alternative comparable arrangement." SEIA supports providing transmission customers with the opportunity to avoid regulation service costs through dynamic scheduling or self-supply arrangements, but ask the Commission to clarify how self-supply would allow solar plants to avoid regulation reserve requirements, which SEIA believes would assign a constantly varying share of the Schedule 10 requirement to a solar plant capable of providing regulation service. The Federal Trade Commission asserts that the self-supply option under Schedule 10 is vague and should recognize that VERs could address their regulation requirements by matching their generation variability to demand variability.

266. Other commenters request that additional requirements be included in Schedule 10 with regard to self-supply. CGC states that the Proposed Rule fails to require public utility transmission providers to provide dynamic transfer capability out of their balancing authority area or provide an ancillary services market through which a generator could self-supply generator regulation service. CGC asks the Commission to require all public utility transmission providers, either by themselves or in association with other public utility transmission providers, to provide access to a fully functioning competitive ancillary services market and/or dynamic transfer capabilities. ELCON asserts that the Commission should specify that public utility transmission providers must

[271] Powerex at 22.

consider using dispatchable demand response resources to provide Schedule 10 service. CESA recommends that FERC allow Schedule 10 self-supply requirements to vary based on the ramp-rate of the resources providing the service, offering that faster-acting resources provide more ACE correction than slower resources.

c. Commission Determination

267. The Commission declines to amend the *pro forma* OATT to include a standardized ancillary services schedule for generator regulation services as proposed in the Proposed Rule. As indicated above, the Commission intended for proposed Schedule 10 to be a clearly defined mechanism for public utility transmission providers to recover the costs of capacity held in reserve to provide generator imbalance service under Schedule 9 of the *pro forma* OATT, while also providing customers with certainty as to the rates they will be required to pay when taking this service. The Commission also sought to confirm the right of public utility transmission providers to recover the reasonably incurred costs of providing this capacity service and to distinguish, where appropriate, among classes of customers who cause such costs to be incurred.

268. In response to the Proposed Rule, the Commission received numerous comments urging flexibility in the design of capacity services needed to integrate VERs into transmission systems, suggesting that the proposed *pro forma* generator regulation service may not be the most efficient and economical service with which to integrate VERs. For example, Southern notes that the recovery of capacity costs incurred to provide Schedule 9 generator imbalance service could implicate a range of services, from regulation to load following, depending on how the public utility transmission provider

conceptualizes the service provided. Iberdrola suggests that VER integration has more significant implications for within hour spinning and non-spinning capacity than moment-to-moment regulation capacity. In light of these comments, the Commission concludes that the adoption of a standardized *pro forma* Schedule 10 could inhibit the flexibility commenters seek to design capacity services that align with the operational needs of a particular public utility transmission provider. Accordingly, the Commission declines to adopt the proposed Schedule 10 component of the Proposed Rule and will continue to evaluate proposals to recover capacity costs incurred to provide Schedule 9 generator imbalance service on a case-by-case basis. In this way, public utility transmission providers will remain free to propose capacity services that best respond to the needs of their customers and will not have to expend resources adopting the one-size-fits-all generator regulation service discussed in the Proposed Rule, even in situations where some other service or rate design may be more appropriate.

269. To be clear, the Commission emphasizes that our decision not to implement a generic rate schedule for generator regulation service should not be interpreted as an unwillingness to consider individual proposals brought by public utility transmission providers. The Commission recognizes that a public utility transmission provider may incur capacity costs associated with fulfilling obligations to provide Schedule 9 generator imbalance service and that existing rate mechanisms may be inadequate for some public utility transmission providers to properly allocate and recover those costs. For many

years, the Commission has evaluated proposals to recover such capacity costs on a case-by-case basis in light of the specific facts and circumstances in each case.[272] The Commission concludes that continuation of this case-by-case approach is more appropriate to tailor the particular capacity services needed by a public utility transmission provider to its operations. At the same time, the Commission is sensitive to commenter requests to provide guidance regarding the proper design of a generator regulation service charge should a public utility transmission provider desire to propose one. In the section that follows, the Commission provides a framework that can be used for those public utility transmission providers seeking to develop a proposal to recover capacity costs incurred to provide Schedule 9 generator imbalance service.[273]

[272] *See Florida Power Corp.*, 89 FERC ¶ 61,263, at 61,765 (1999) (*Florida Power*) ("The Commission concludes that a generator imbalance capacity obligation is imposed on the transmission provider for export transactions, and therefore the Commission accepts Florida Power Corp's Generator Regulation Service as a reasonable proposal in those circumstances where the service is not already covered in an interconnection agreement or a separate generator tariff."); *Entergy*, 120 FERC ¶ 61,042 at PP 62-66 (accepting a generator regulation service rate schedule for independent power producers selling out of the control area that retained charges that had been previously negotiated between Entergy and the relevant independent power producers); *Sierra Pac. Res. Operating Cos.*, 125 FERC ¶ 61,026, at P 10 (2008) (accepting a generator regulation service rate schedule to provide the capacity necessary to follow the moment-to-moment changes caused by generators selling outside of the transmission provider's control area).

[273] *See infra* § IV.C.2 (Mechanics of a Generator Regulation Charge). While this section is framed primarily in terms of a generator regulation service, the principles discussed would also apply more broadly to other capacity services designed to recover capacity costs incurred to provide Schedule 9 generator imbalance service.

270. Before turning to the mechanics of a generator regulation service charge, the Commission clarifies in response to comments that our decision not to adopt a generic Schedule 10 does not relieve public utility transmission providers of obligations under the *pro forma* OATT to provide Schedule 9 generator imbalance service. This in turn requires the public utility transmission provider to maintain sufficient capacity to provide that service.[274] However, as the Commission explained in Order No. 890-A, if it is not physically feasible for a transmission provider to offer generator imbalance service using its own resources, either because they do not exist or they are fully subscribed, the public utility transmission provider must attempt to procure alternatives to provide the service, taking appropriate steps to offer an option that customers can use to satisfy their obligation to acquire generator imbalance service as a condition of taking transmission service.[275] The Commission explained that each transmission provider can state on its OASIS the maximum amount of generator imbalance service it is able to offer from its resources, based on an analysis of the physical characteristics of its system. Alternatively, a public utility transmission provider may consider requests for generator imbalance service on a case-by-case basis, performing, as necessary, a system impact

[274] *NorthWestern Corp.*, 129 FERC ¶ 61,116, at P 24 (2009), *order denying reh'g*, 131 FERC ¶ 61,202, at PP 17-18 (2010).

[275] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at PP 289-90.

study to determine the precise amount of additional generation it can accommodate and still reliably respond to the imbalances that could occur.[276]

271. Because a proposal for generator regulation service would be associated with generator imbalance service, it follows that the public utility transmission provider would use a similar analysis to identify any limitations on its ability to offer either service.[277] Just as it can for generator imbalance service, the public utility transmission provider could explain on its OASIS the maximum amount of generator regulation service it is able to offer after having attempted to procure alternative resources to provide the service. Alternatively, the public utility transmission provider could perform a system impact study to determine the precise amount of generator regulation service it can provide. In response to NorthWestern, this Final Rule does not place any obligation on the public utility transmission provider to build generation.

272. With regard to comments regarding self-supply of ancillary services, the Commission acknowledges that self-supply may come from many sources, including purchased capacity and the use of non-generation resources, as suggested by ELCON. The option to self-supply certain ancillary services has been in place since Order No. 888, and the Commission declines here to specify any particular requirements for self-supply

[276] *Id.* P 289.

[277] In the unlikely event that there are no additional resources available to enable the public utility transmission provider to meet its obligation to offer generator regulation service, the public utility transmission provider must accept the use of dynamic scheduling with a neighboring control area. *See id*. P 290.

arrangements for generator regulation service proposals. To do so could restrict flexibility to develop competitively priced options tailored to particular customer needs. As suggested by some commenters, such options could include the use of faster ramping resources to provide the service.

273. In response to Powerex, the Federal Trade Commission and others, the Commission does not believe that the self-supply option is vague or that additional guidance is necessary on what should qualify as an "alternative comparable arrangement." The Commission notes that public utility transmission providers already are obligated to post on their public websites all rules, standards, and practices, to the extent they exist, that relate to transmission service.[278] The provision of ancillary services is necessary to accomplish transmission service and, therefore, we conclude this posting obligation applies equally to ancillary services[279]. Public utility transmission providers must post any rules, standards, and practices regarding self-supply requirements pursuant to their obligation to allow self-supply of ancillary services.[280] The Commission declines to adopt further requirements at this time regarding the self-supply of ancillary services.[281]

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[278] Order No. 890, FERC Stats.& Regs. ¶ 31,241 at P 1652.

[279] The Commission notes that this obligation is subject to audit as are all other OATT requirements.

[280] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,705.

[281] *Id.*

274. In response to the Federal Trade Commission, the Commission encourages transmission providers, generators, and transmission customers to work together to explore options to find the least cost methods of balancing the system as a whole and to provide maximum flexibility for products and services that meet the needs of the customers and the transmission providers alike. This includes, for example, evaluating the extent to which regulation service obligations can be addressed by matching generation variability to demand variability, as suggested by the Federal Trade Commission. Indeed, in Order No. 888, the Commission stated that the pricing of ancillary services should include the amount of each ancillary service that the transmission customer must purchase, self-supply, or otherwise procure and must be readily determinable from the transmission provider's tariff and comparable to obligations to which the transmission provider itself is subject.[282] The Commission also specified that the transmission provider is required to identify the regulating margin requirements for transmission customers serving loads in its balancing authority area and to develop procedures by which customers can avoid or reduce such requirements.[283]

[282] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,721.

[283] *Id.* at 31,717. Order No. 890 did not alter the requirements of Order No. 888 in this regard, but did clarify that regulation and frequency response, as well as imbalance energy, may be provided by public utility transmission providers or through self-supply using generating units as well as other non-generation resources such as demand resources where appropriate. Order No. 890, FERC Stats. & Regs. ¶ 21,241 at P 888.

275. For reasons explained elsewhere in this Final Rule, the Commission declines to adopt CGC's suggestion to require transmission providers to provide dynamic transfer capability out of their balancing authority area or mandate the creation of an ancillary services market through which a generator could self-supply generator regulation service.[284]

2. Mechanics of a Generator Regulation Charge

276. The Proposed Rule stated that, as with Schedule 3, the proposed Schedule 10 charge would be the product of two components: a per-unit rate for regulation reserve capacity, and a volumetric component for regulation reserve capacity.[285] The Commission proposed to require each public utility transmission provider to submit a compliance filing that includes the addition of a Generator Regulation and Frequency Response rate schedule to the OATT that includes the same per unit rate from their currently effective Regulation and Frequency Response rate schedule and a blank or unfilled volumetric component.[286]

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[284] *See supra* IV.A.1 (Intra-Hour Scheduling Requirement).

[285] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 92. The Commission is exploring potential reforms to ancilliary services pricing in other proceedings. *See Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologi*es, Notice of Proposed Rulemaking, 139 FERC ¶ 61,245 (2012) (NOPR).

[286] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 101.

277. The Commission preliminarily found that the per-unit rate for service under proposed Schedule 10 should be the same as the rate for service under existing Schedule 3.[287] The Commission explained that Schedule 3 and the proposed Schedule 10 are both designed to recover the costs of holding regulation reserve capacity to meet system variability. Because the service provided under both schedules is functionally equivalent, the Commission proposed to find that it is just and reasonable to use the same rate currently established in a public utility transmission provider's Schedule 3 when charging transmission customers under Schedule 10. The Commission stated that, for a public utility transmission provider to apply a different rate under the proposed Schedule 10, the public utility transmission provider would have to demonstrate that the per-unit cost of regulation reserve capacity is somehow different when such capacity is utilized to address system variability associated with generator resources. The Commission also noted that the use of a common rate is consistent with Commission policy utilizing the same rate structure for energy and generator imbalance service, as well as the generator regulation rate that the Commission accepted in *Westar Energy Inc.*[288]

278. With regard to the volumetric component of the Schedule 10 rate, the Commission proposed to provide each public utility transmission provider with the opportunity to justify a proposal: (1) to require all transmission customers who are delivering energy

[287] *Id.* P 94.

[288] *Id.* P 93 (citing *Westar Energy Inc.*, 130 FERC ¶ 61,215 (2010) (*Westar*)).

from generators to purchase, or otherwise account for, the same volume of generator regulation reserves; or (2) to require transmission customers who are delivering energy from VERs to purchase, or otherwise account for, a different volume of generator regulation reserves than it proposes to charge transmission customers delivering energy from other generating resources.[289] The transmission provider's proposal would be made in a section 205 filing after the acceptance of its compliance filing.

279. Where a public utility transmission provider proposes the same volume of generator regulation reserves for all generators, the Commission proposed that it demonstrate that the volume of regulation reserves required of transmission customers delivering energy from generators located within its balancing authority area be commensurate with their proportionate effect on net system variability, taking account of diversity benefits.[290] The Commission stated that such a filing must show that the public utility transmission provider has fully implemented (or been granted waiver from) the

[289] The Commission noted its expectation that, in any subsequent filing to establish a volumetric component in Schedule 10, public utility transmission providers would address how Schedule 10 and Schedule 3 work together to allow for the recovery of total regulation reserve costs. *Id.* P 105 & n.206.

[290] The Commission explained that diversity benefits result from the aggregation of the variations of all resources such that one resource's negative deviation can offset some or all of another resource's positive deviation. The Commission stated that, when the transactions of two customers result in diversity benefits, it is incorrect to say that one customer is benefitting the other but not vice versa. Instead, the Commission preliminarily found that diversity benefits would result from both transactions and that sharing of these benefits among the customers would be reasonable. *Westar*,130 FERC ¶ 61,215 at P 37.

intra-hourly scheduling requirement set forth in the Proposed Rule.[291] The Commission recognized that a public utility transmission provider with few VERs located in its balancing authority area may choose to apply only one volumetric regulation requirement for all generating resources in its balancing authority area. The Commission noted that this also may be the case to the extent the impact of VERs on a public utility transmission provider's system is minimal and the public utility transmission provider, in its judgment, deems the administrative burden of justifying two separate volumetric regulation requirements is uneconomic.[292]

280. The Commission proposed that where a public utility transmission provider proposes to require transmission customers who are delivering energy from VERs to purchase, or otherwise account for, a different volume of generator regulation reserves than it proposes to charge transmission customers delivering energy from other generating resources, the Commission proposed that it demonstrate that the volumes of regulation reserves required of those subsets of transmission customers delivering energy from generators located within its balancing authority area are commensurate with their proportionate effect on net system variability and taking account of diversity benefits.[293] That is, any proposal for different volumes of generator regulation reserves based on the

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[291] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 105.

[292] *Id.* P 94.

[293] *Id.* P 106.

generating resource would need to be supported by data showing that, on the public utility transmission provider's system, VERs have a different per unit impact on overall system variability than conventional generating units.[294] The Commission proposed that such a filing must also show that the public utility transmission provider has fully implemented (or been granted waiver from) the intra-hourly scheduling requirement set forth in the Proposed Rule and has developed and deployed power production forecasting for VERs.[295]

281. Specifically, the Commission proposed that any filing by public utility transmission providers including different volumetric requirements for different subsets of transmission customers must be supported with actual data collected over a one-year period subsequent to the deployment of power production forecasting for VERS and the implementation of intra-hourly scheduling at 15-minute intervals. The Commission acknowledged that this proposal could delay a public utility's ability to recover the cost associated with providing generator regulation service. The Commission further acknowledged that there may be alternative methods for developing the data necessary to support different volumetric requirements for different subsets of transmission customers. The Commission sought comment as to such methods of demonstration, how they could support a Commission finding that the Schedule 10 filing is just and reasonable, and

[294] *Id.* P 95.

[295] *Id.* P 106.

ways in which these methods of demonstration may be preferable to this aspect of the Commission's proposal.[296]

282. In the Proposed Rule, the Commission stated that the increased use of power production forecasts in transmission systems where VERs are located can provide transmission providers with improved situational awareness, enable transmission providers to utilize existing system flexibility through the unit commitment and dispatch processes, and, ultimately, lead to a reduction in the amount of reserve products needed to maintain system reliability. The Commission also recognized that, in areas of the country with very limited production from VERs, the implementation of power production forecasting for VERs could be less useful.[297] The Commission sought comment in the Proposed Rule on the manner by which a public utility transmission provider should be required to show it has developed and deployed power production forecasts to support a proposal to require a differentiated volumetric component of rates for generator regulation reserves under proposed Schedule 10.[298]

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[296] *Id.* P 107.

[297] *Id.* P 55 n.125.

[298] *Id.* P 106.

a. Comments

i. General

283. Invenergy Wind requests that the Commission clarify that, in requiring initial Schedule 10 charges to adopt the utility's then-effective Schedule 3 charges, the application of the rate will be consistent. Invenergy Wind states that Schedule 3 charges are typically applied on the basis of a percentage of the customer's schedule. Beacon Power questions the reliance on existing regulation service charges, stating that a transmission provider in non-RTO/ISO markets could optimize the performance of its existing fleet to potentially lower costs to customers under Schedule 3 or 10. Beacon Power requests that the Commission encourage such transmission providers to evaluate the technologies and benefits they provide. Xtreme Power agrees, asking the Commission to require public utility transmission providers to make a showing that the rates proposed for Schedule 10 are based on an appropriate type and quantity of resources needed, considering the technologies available in the market today rather than using dated rates from Schedule 3. CESA suggests that the reforms proposed for Schedule 3 in the Commission's Frequency Regulation Notice of Proposed Rulemaking be included in Schedule 10 for RTO and ISO markets.[299]

[299] CESA; *See also Notice of Proposed Rulemaking on Frequency Regulation Compensation in the Organized Wholesale Electric Markets*, 134 FERC ¶ 61,124 (2010) (Frequency Regulation NOPR); *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 76 FR 67260 (Oct. 31, 2011), FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied*, Order No. 755-A,138 FERC ¶ 61,123 (2012).

284. Some commenters suggest that public utility transmission providers be permitted to recover opportunity costs associated with providing generator regulation service.[300] For example, the Large Public Power Council states that, consistent with the decision in *Puget*, generator regulation service rates should be fully compensatory, and may legitimately reflect a utility's full opportunity cost.[301] According to Puget, there may also be lost opportunity costs associated with reserving unloaded generation capacity during peak market conditions. NRECA argues the integration of a significant amount of VERs will cause the Schedule 3 rate to rise as Schedule 10 demand increases particularly in regions with a lot of hydropower, where the additional VERs cause the need for more thermal reserves, which are more expensive than the existing reserve rate base.

ii. Quantity of Reserves

285. Some commenters request further direction from the Commission regarding the calculation of the volumetric component of Schedule 10, i.e., the quantity of reserves transmission customers are required to purchase or otherwise account for.[302] For example, the California PUC asserts that the Commission should recommend or require that a public utility transmission provider consider the system's resource mix and the amount of operational flexibility of the transmission system's generation fleet to develop

[300] *E.g.*, SMUD; WUTC; EEI; Large Public Power Council; Puget.

[301] *E.g.*, Large Public Power Council (citing *Puget Sound Energy*, 132 FERC ¶ 61,128 (2010)).

[302] *E.g.*, CPUC; LADWP; SEIA.

the volumetric component of Schedule 10. LADWP indicates that measures of alleged diversity benefits may lead to unintended results if significant diversity occurs in one part of a year and forms the basis for a smaller volumetric component than is necessary for another part of the year.

286. Some commenters question whether the Commission should allow public utility transmission providers the opportunity to file for differentiated volumetric rates under Schedule 10. AWEA contends that it would be unjust and unreasonable and break with Commission precedent to allocate to generators the costs of Schedule 10, whether kept as a regulation reserve or reformulated to a system non-spin service, while allocating other ancillary services costs broadly to load. AWEA states that all users of the grid add variability and uncertainty and that all benefit when the grid is better able to accommodate variability and uncertainty. AWEA also argues that the capacity used to provide Schedule 10 service would be available to provide a number of other ancillary services, not to mention to the public utility transmission provider to meet peak demand.

287. Western Grid states that the integration costs of other types of generation are largely ignored and the regulation and frequency costs imposed by large loads are broadly socialized. Western Grid therefore contends that grid integration costs related to VERs should be recovered in a manner comparable to the way grid integration costs imposed by large conventional generators are recovered. Argonne National Lab argues that calculating the net impact of VERs on regulation service needs is likely to be difficult and contentious and that to ensure just and reasonable treatment of all resources, the Commission should be careful in imposing specific requirements on VERs without

considering the specific impacts on system reliability and operating reserve costs from other generating resources as well. Similarly, the Federal Trade Commission recommends that the Commission consider whether the costs of imbalance services provided to other types of generators can readily be identified and charged to the responsible parties.

288. Some commenters support the proposal to condition the implementation of differentiated volumetric rates on whether that transmission provider has implemented power production forecasting and intra-hour scheduling reforms.[303] AWEA states that Schedule 10 should not be charged at all until a transmission provider has fully implemented the Efficient Dispatch Toolkit and the Commission's proposed sub-hourly scheduling and variable energy forecasting operating reforms. Clean Line states that implementation of forecasting should be required before any special charges are assigned to renewable generators. Clean Line argues that, before transmission providers can charge a just and reasonable rate to recover ancillary service costs, they must use reasonable means to minimize those costs – such as forecasting.

289. Some commenters suggest that differentiated volumetric rates should be conditioned on implementation of additional reforms beyond those set forth in the

[303] *E.g.*, AWEA; BP Energy; Iberdrola; Independent Power Coalition West; NextEra; Oregon & New Mexico PUC; Public Interest Organizations; Vestas.

Proposed Rule.[304] For example, Environmental Defense Fund maintains that a public utility transmission provider should not be permitted to establish different volumetric reserve requirements for VERs unless it has demonstrated to the Commission that the balancing authority area is optimally sized or cooperating with other balancing authority areas. Oregon & New Mexico PUC similarly state that Schedule 10 charges for VERs should be conditioned on a demonstration by the public utility transmission provider regarding the measures it has considered to increase cooperation with other balancing authorities to lower the cost of integrating wind and solar. First Wind argues that public utility transmission providers should only be permitted to charge for generator regulation service once they have implemented procedures for dynamic transfers in addition to intra-hour scheduling. CESA contends that, before imposing any generator regulation costs on VERs, public utility transmission providers should first implement fast intra-hour markets and intra-hourly scheduling; a robust ancillary services market; the option for third-party or self supply of ancillary services; dynamic transfer capability out of the balancing authority area; and Area Control Error (ACE) diversity interchange or an energy imbalance service market.

290. In contrast, ELCON asserts that Schedule 10 as proposed is a mechanism for the socialization of costs that should be directly assigned to VERs or their customers. Grant PUD argues that variable loads and variable resources should be charged differently for

[304] *E.g.*, Iberdrola; First Wind; Oregon & New Mexico PUC; Environmental Defense Fund.

regulation service according to the nature of the different costs placed on the public utility transmission provider. A number of other commenters agree, objecting to any delay in cost recovery associated with providing generator regulation service.[305] For example, Pacific Gas & Electric and Idaho Power argue that public utility transmission providers incur costs to provide generator regulation service regardless of whether they are employing intra-hourly scheduling and, thus, preventing recovery of generator regulation service costs shifts those costs to other customers in violation of cost causation principles.

291. EEI opposes requiring a public utility transmission provider to commit specific actions before seeking rate recovery under section 205, particularly when such actions violate cost causation principles. EEI states that as articulated by the Commission in *Northern States Power Company*, "[t]he *fundamental* theory of Commission ratemaking is that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the cost to be incurred."[306] According to EEI, the D.C. Circuit echoed this sentiment in *KN Energy, Inc. v. FERC*, "[s]imply put, it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer

[305] *E.g.*, Tacoma Power; Montana PSC; Pacific Gas & Electric; PNW Parties; NV Energy; Public Power Council; Natural Gas; WUTC.

[306] EEI at 29 (citing *N. States Power Co.*, 64 FERC ¶ 61,324, at P 13 (1993) (emphasis supplied) (citations omitted)).

who must pay them."[307] EEI and others state that, to the extent the Commission conditions generator regulation service cost recovery on implementing the Proposed Rule's reforms, the Commission should explain how such a limitation does not effectively force public utility transmission providers to waive their sections 205 and 206 rights under the FPA in contravention of *Atlantic City Electric Company*.[308]

292. Southern opposes conditioning public utility transmission providers' rights to recover rates under section 205 of the FPA for generator regulation and frequency response service on the implementation of such reforms. Southern argues that utilities have a statutory right to establish just and reasonable rates under sections 205 and 206 of the FPA. If the Commission pursues these limitations, Southern asks the Commission to explain how such a limitation does not effectively force public utility transmission providers to waive their section 205 and 206 rights.

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[307] EEI at 29 (citing *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009); *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009); *Pub. Serv. Comm. of Wisc. v. FERC*, 545 F.3d 1058, 1067 (D.C. Cir. 2008); *Pac. Gas & Electric Co. v. FERC*, 373 F.3d 1315, 1320 (D.C. Cir. 2004)).

[308] EEI at 27-28 (citing *Atlantic City Elec. Co.*, 295 F.3d 1, 10 (2002) (finding that the Commission lacks the authority to require public utility transmission providers to cede their rights under section 205 of the FPA); MidAmerican at 26; Puget at 17 (questioning whether whether requiring one-year of data reporting interferes with a public utility transmission provider's rights under section 205 of the FPA); WUCT at 7 (questioning whether requiring 15-minute scheduling and one-year of data reporting interfere with a public utility transmission provider's rights under section 205 of the FPA)).

293. LADWP argues that the proposed requirements would place public utility transmission providers in a defensive role. LADWP states that presuming a public utility transmission provider makes a sufficient showing that it implemented intra-hour scheduling and deployed power production forecasting for VERs, a transmission provider is further compelled to demonstrate the basis for any difference in regulating reserves between VER transmission customers and non-VER transmission customers. LADWP argues that this could put the public utility transmission providers in a defensive role of justifying the findings and conclusions within a system impact study report, in the event performed by the public utility transmission provider.

iii. Power Production Forecasting

294. Some commenters state specific opposition to linking power production forecasting to the implementation of differentiated volumetric rates under Schedule 10.[309] Southern argues the Commission would exceed its statutory authority if it required implementation of power production forecasting. Southern states courts have recognized that the Commission "is a 'creature of statute,' having no constitutional or common law existence or authority, but only those authorities conferred upon it by Congress."[310] Southern contends that, because the FPA never mentions meteorological forecasting, it is

[309] *E.g.*, Bonneville Power; Montana PSC; Natural Gas; Public Power Council; Puget Sound Energy; NV Energy.

[310] Southern (citing *Cal. Indep. Sys. Operator Co. v. FERC*, 372 F.3d 395, 398 (D.C. Cir. 2004) (citing *Atlantic City Elec. Co. v. FERC*, 295 F.3d at 8)).

beyond the scope of the Commission's authority. Southern explains that public utilities have long engaged in meteorological forecasting for load forecasting and dispatch purposes; however, there never has been an indication that such practices were within the scope of the Commission's jurisdiction, and the advent of VER generation has not added such forecasting to the scope of the Commission's authority.

295. While Bonneville Power acknowledges that centralized power production forecasts will facilitate system-wide benefits, Bonneville Power disagrees that such forecasts should be a prerequisite to the cost recovery of balancing reserve capacity used to provide generator regulation reserve-type services. Bonneville Power believes that such a requirement would shift costs to other users of the transmission system that would not be otherwise incurred but for the VER generation. Puget believes that requiring transmission providers to implement power production forecasting as a precondition to Schedule 10 cost recovery inappropriately shifts the costs of integrating VERs from the VER to the balancing authority. Southern argues that meteorological forecasting issues are business decisions that are best left to the transmission providers and the market. EEI states that it is not convinced that the power production forecasting requirements are necessary to support requiring a higher volumetric amount of Schedule 10 regulation service. According to EEI, the data necessary to substantiate a higher volumetric charge can be derived by analyzing the deviation between a VER's scheduled versus actual production. EEI, therefore, claims that requiring a public utility transmission provider to implement power production forecasting prior to establishing a higher volumetric rate creates a barrier to cost recovery.

296. Montana PSC notes that the Proposed Rule's data reporting requirements to support power production forecasting would only apply to generators that are 20 MW or larger. Montana PSC argues that conditioning differentiation of volumetric rates on the implementation of power production forecasting could unduly restrict application of Schedule 10 generation regulation charges to smaller resources. Montana PSC argues that all VERs one MW or greater should be responsible for Schedule 10 services that they cause.

297. Other commenters ask the Commission to mandate use of power production forecasting by all public utility transmission providers with significant amounts of VERs instead of relying on the public utility transmission owner's decision to charge differentiated Schedule 10 rates.[311] The ISO/RTO Council argues that, while transmission providers in areas with low to moderate levels of VER interconnection may be able to manage variability on their systems without using power production forecasting, areas with larger levels of VERs should be required to adopt power production forecasting tools to ensure that conditions affecting generation output can be anticipated and managed appropriately. SEIA suggests that each transmission provider that provides interconnection to or has interconnections with more than 50 MW of VERs should be required to develop a power production methodology to accommodate integration of VERs. First Wind contends that power production forecasting should be

[311] *E.g.*, CPUC; ISO RTO Council; Midwest ISO; SEIA.

mandatory for public utility transmission providers with five percent of VER resources on their system. CPUC asks that the Commission clarify that any public utility transmission provider may require power production forecasting if VERs are currently or anticipated to become significant.

298. Some commenters support the Commission's recognition that certain regions may not have a need for VER power production forecasting because of a low likelihood of VERs development.[312] For example, Bonneville Power states that the requirement to implement centralized forecasting should not apply if the penetration of VERs is less than 10 percent of load served. Puget argues that it should not be required to use power production forecasting because it only serves one exporting VER in its region.

299. Several commenters provide detailed discussions of the various activities that public utility providers should be required to undertake in order to show power production forecasting is in use. Public Interest Organizations suggest that the Commission require public utility transmission providers to demonstrate that VER power production forecasts are incorporated into unit commitment, scheduling, and dispatch efforts. Oregon & New Mexico PUC state that at a minimum, a public utility transmission provider needs to demonstrate that it has requested meteorological and operational data from wind and solar generators and has integrated forecast information into control room operations.

[312] *E.g.*, Bonneville Power; NextEra; PNW Parties.

300. Some commenters contend that the public utility transmission provider should demonstrate that it is using the VER forecast to efficiently and reliably commit and dispatch resources. These parties offer various criteria regarding costs, accepted industry practices, and performance metrics that should be required of public utility transmission providers in order to be deemed compliant with the Final Rule.[313] The California PUC states that, while it does not recommend that the Commission set specific minimum quality standards or cost maximums for VERs forecasts at this time, the Commission should monitor results of public utility transmission providers' assessments. If the quality of forecasts varies significantly among public utility transmission providers, the Commission may determine that minimum quality standards or maximum cost limits for VERs forecasts are necessary to prevent unjust, unreasonable, or unduly discriminatory rates.

301. Other commenters argue that the Commission should ensure that the risks associated with inaccurate schedules or resource specific forecasts remain with the VER.[314] Montana PSC states that the forecasting requirement should be the responsibility of VER instead of the public utility transmission provider. NorthWestern states that it is inappropriate to make the public utility transmission provider responsible for forecasting the VER power output when it is the responsibility of the VER to provide

[313] *E.g.*, AWEA; California PUC; Iberdrola; NaturEner.

[314] *E.g.*, AEP; Large Public Power Council; Midwest ISO Transmission Owners; Montana PSC; NorthWestern.

its schedule. NorthWestern points out that, if the public utility transmission provider provides a forecast of the VER power production, as proposed by the Proposed Rule, and the VER submits a different schedule, Control Performance Standard 2 violations may occur that would not have occurred if an accurate power production forecast had been submitted by the VER. NorthWestern argues that the forecasting requirement would place the balancing authority in an unacceptable position if the forecast or power production data is inaccurate. Midwest ISO Transmission Owners state that regardless of whether the public utility transmission provider requires VERs to provide meteorological data or employs other tools in order to increase the effectiveness of scheduling and dispatching activities, all generation resources must retain the ultimate responsibility for determining their unit's deliverability; accordingly, variations from scheduled deliveries must remain the responsibility of the generating resource, including VERs.

302. Bonneville Power argues that, if the Commission requires centralized power production forecasts for public utility transmission providers with significant amounts of VERs on their systems that intend to differentiate their Schedule 10 pricing, it is preferable that the Commission also require all VERs to schedule according to the centralized forecast component for each plant. Puget explains that, if the public utility transmission provider's forecast sets the schedule, then there could be a perverse incentive for public utility transmission providers to generate inaccurate forecasts and collect larger generator imbalance charges under Schedule 9; however, if the VER is permitted to set its own schedule that differs from the public utility transmission provider's forecast, it remains unclear how the public utility transmission provider is

supposed to manage and deploy its resources -- according to its own forecast or to the VER's schedule. Puget requests that these questions be clarified before the Commission implements a power production forecasting requirement for public utility transmission providers, whether as a stand-alone mandate or as a precondition to Schedule 10 cost recovery.

303. Invenergy argues that the Final Rule should hold public utility transmission providers: (1) accountable for the accuracy of the forecasts that they use to determine regulation capacity requirements; and (2) to performance levels that current technology supports. Invenergy states that ISOs and RTOs that have implemented centralized wind forecasting are generally realizing accuracy rates of 89 percent or greater. Invenergy argues that the Final Rule should require the public utility transmission provider to provide customers with forecasting performance metrics on a periodic basis and, if forecasts do not prove to be reliable, require the public utility transmission provider to take immediate steps (including improving its forecasting systems and equipment or relinquishing responsibilities to an independent third party) to ensure that future forecasts are accurate.

304. Commenters state that in RTO regions, the RTO would be the more appropriate entity to conduct power production forecasting. National Grid asks the Commission to clarify who the "transmission providers" are that will undertake the energy forecasting responsibility. National Grid states that the role of developing and implementing energy forecasting tools is well suited to a centralized entity with existing capabilities in data collection, region wide system forecasting and centralized dispatch responsibilities such

as RTOs and ISOs. National Grid requests that the Commission clarify that for the purposes of its data forecasting Final Rule the term "transmission provider" means the ISOs or RTOs in those regions, as this avoids confusion where the term "transmission provider" can refer to either the ISO or its members.

305. Some commenters point out that many regions are currently undertaking their own forecasting and data gathering initiatives or programs to integrate VERs, and request that the Commission allow for regional flexibility.[315] Pacific Gas & Electric requests that individual public utility transmission providers be given flexibility on how to implement that requirement. Pacific Gas & Electric requests that in its Final Rule the Commission provide latitude for the California ISO and other similarly situated transmission providers to continue their existing programs to gather the relevant meteorological and operational data, and to propose incremental refinements to them, so long as the programs maintained by these transmission providers can accomplish the purposes set forth in the Proposed Rule for gathering this information.

iv. One Year Data Requirement

306. Some commenters contend that the proposal to require public utility transmission providers to collect power production forecasting data for one year prior to instituting a differentiated regulation requirement for VERs violates cost causation principles and

[315] *E.g.*, Massachusetts DPU; Pacific Gas & Electric; Midwest ISO.

imposes costs of balancing reserve capacity needed for VERs on other customers.[316] Such commenters maintain that the one-year data collection requirement unreasonably delays public utility transmission providers from demonstrating that they are entitled to recover different volumetric amounts associated with providing generator regulation service from different types of generators.[317] Bonneville Power argues that there may be sound economic and operational bases for providing or procuring differential quantities of incremental and decremental balancing reserve capacity. Western Farmers suggest that the Commission allow public utility transmission providers to propose the volumetric component of the Schedule 10 charge along with the proposed rates in their initial Schedule 10 compliance filing. Natural Gas and Puget similarly argue that public utility transmission providers should have an opportunity to allocate ancillary service costs as soon as they are justifiably able to do so. MidAmerican contends that the one-year data collection requirement is inconsistent with the *Westar* precedent.

307. Some commenters suggest that public utility transmission providers should be permitted to establish rates using historical data, subject to adjustment as necessary over time.[318] For example, Bonneville Power states that rates can be updated as public utility

[316] *E.g.*, Bonneville Power; Puget; MidAmerican; Southern California Edison; Natural Gas.

[317] *E.g.*, EEI ; MidAmerican; Puget; WUTC.

[318] *E.g.*, Bonneville Power; Southern California Edison; California PUC; EEI; NorthWestern.

transmission providers gain experience with reductions in the need for balancing reserve capacity requirements associated with intra-hourly scheduling, centralized forecasting and any other initiatives. Similarly, Puget suggests that reductions in the VERs volumetric component could be incorporated into a subsequent rate filing after implementation of 15-minute scheduling and power production forecasting by the utility. NorthWestern suggests that, just as the Commission routinely allows a proposed rate to take effect on an interim basis subject to refund until final approval is received, the Commission likewise should consider applying a similar principle in allowing interim regulating service cost recovery. Pacific Gas & Electric proposes that until one year's worth of data are available, public utility transmission providers should be able to use simulated data to estimate the relative contribution of load, imports, VERs and other generation for the overall need for generator regulation reserves.

308. In contrast, Vestas argues that public utility transmission providers should be required to implement the two operational changes immediately and then collect data over at least the next 12 months regarding the levels of schedule deviations on their systems for all types of generation. According to Vestas, the Commission should require the submission of that data to the Commission and take comments from interested market participants on the appropriate rate mechanism to permit the recovery of any costs incurred to address remaining variations between generator schedules and generator output.

309. Organization of Midwest ISO States asks the Commission to require public utility transmission providers with significant VER capacity, such as three percent or more of

total capacity, to submit statistical data on the variability of generation across the different types of generation resources and load. If there is a significant difference between types of resources, Organization of Midwest ISO States contends that the public utility transmission provider should be required to allocate the costs of increased regulation and other ancillary services developed in the future to the generation resources causing those costs.

v. Other

310. Some commenters express concern about the static nature of the rates and volumes in Schedule 10.[319] SEIA argues that public utility transmission providers who have selected a methodology and begun to apply different Schedule 10 rates for different categories of customers should be required to revisit their forecasting methodologies and rates on a regular basis. RenewElec notes that data collected over a one-year period that may feature anomalies (e.g., wind droughts). RenewElec suggests that the Commission require transmission providers to retain data provided under the new *pro forma* LGIA Article 8.4 for at least 10 years and commit to performing annual follow-up studies over a period of not less than five years that update power production forecasts with new data received. RenewElec suggests that the Commission include a biannual re-opener provision for VER-specific Schedule 10 charges, or through other review and implementation combinations.

[319] *E.g.*, SEIA, RenewElec, NaturEner.

311. NaturEner asserts that an annual re-evaluation of the integration charge needs to be undertaken to take into account the impact of increased diversity, improved operations, market innovations and other changed circumstances, as well as to correct any inaccuracy in the original (or immediately prior) assessment. NaturEner also requests clarification regarding whether a VER transmission customer could be required to pay a VER integration charge in arrears if a public utility transmission provider is subsequently permitted to levy the charge.

312. Some commenters oppose the Commission's proposal to group resources together for the purpose of allocating Schedule 10 volumes.[320] For example, BrightSource states that assigning all VERs the same regulation requirement could distort the incentives created by the cost allocation if they are evaluated as a single, undifferentiated class. First Wind asserts that the rate should be designed to recognize the actual variability of output of the resource paying the rate because two wind generation projects of the same installed capacity and energy production might have different levels of variability due to factors such as local differences in the variability of the "wind resource" (the relative wind generating value of the location); the number, size, and manufacturer of the wind turbines; and differences in distances between wind turbines. RenewElec offers that high capacity wind generation units have a disproportionally smaller impact on variability than lower capacity units. According to AWEA, the variability of resources within a category

[320] *E.g.*, BrightSource; FirstWind; RenewElec; AWEA.

cancels each other out to the benefit of those resources in that category, imposing a disadvantage on customers that are grouped in smaller categories.

313. Snohomish County PUD questions whether it is appropriate to apportion any volume of generator regulation reserves to behind-the-meter generation. Snohomish County PUD contends that variations in output from the behind-the-meter generator are, from the perspective of the public utility transmission provider, indistinguishable from variations in the distribution utility's load. Accordingly, Snohomish County PUD asks the Commission to clarify that behind-the-meter generators–those that are interconnected directly to and consumed by the load of the local distribution utility rather than a transmission utility–will not be required to purchase generator balancing capacity from the public utility transmission provider in the absence of a voluntary agreement between the public utility transmission provider and the generator to install appropriate metering that measures the variability of the generator and to pay the Schedule 10 charges justified by that variation.

314. Several commenters suggest that the Commission convene a technical conference or require other processes to determine the appropriate per-unit and volumetric rates under the proposed Schedule 10.[321] AWEA states that a technical conference would be appropriate to establish consistent principles for determining the methodology that should be used for calculating and allocating Schedule 10 costs. Some commenters request that

[321] *E.g.*, AWEA; BrightSource; EPSA; SEIA.

the Commission require stakeholder involvement in connection with the development of Schedule 10 volumes.[322] For example, First Wind requests that the Commission require RTOs to conduct a robust and transparent stakeholder process which attempts to reach consensus prior to them making an allocation filing, and that non-RTO public utility transmission providers conduct public workshops prior to any allocation filing.

b. Commission Determination

315. For the reasons discussed above, the Commission is not implementing a generic Schedule 10 to the *pro forma* OATT for generator regulation service. Instead, the Commission takes this opportunity to respond to the individual commenter concerns regarding the proper design of a generator regulation service charge in order to provide guidance in the development of proposals for such services.

316. In response to the Large Public Power Council and Puget, those public utility transmission providers that choose to propose a rate schedule for generator regulation service may include opportunity costs for generator regulation service in certain circumstances. Such resources are often dispatched in the middle of their operating range to allow the generator to provide regulation-up as well as regulation-down and as a result forego other opportunities. Not to allow compensation would create a barrier to the provision of services by frustrating the recovery of legitimate costs.

[322] *E.g.*, California PUC; First Wind; SEIA.

317. A number of commenters question the appropriate design of the volumetric component of Schedule 10 rates, i.e., the component in the Proposed Rule that allowed public utility transmission providers to require different transmission customers (or generator classes) to purchase or otherwise account for different quantities of regulation reserves based on cost causation principles. The Commission agrees that calculating the relative impact of individual customers or customer classes on a public utility transmission provider's overall generation regulating reserve needs and allocating those costs accordingly can be a difficult and complex determination. However, the Commission believes that the complexity of these proceedings can be mitigated where entities take note of, and incorporate, the following principles.

318. First, public utility transmission providers seeking to distinguish customers into classes for the purpose of requiring them to purchase or otherwise account for different quantities of generation regulating reserves should do so only to the extent such classes and distinctions among classes are reasonably related to operational similarities and differences among those resources.[323]

319. Second, to the extent a public utility transmission provider proposes to break customers into specific groups based on operational characteristics, we expect public utility transmission providers to provide detailed explanations as to why such classifications are appropriate if and when they propose to allocate different generating

[323] *See Westar*, 137 FERC ¶ 61,142 at PP 27-28.

regulation reserve obligations to different customer classes. The Commission has required that overall generator regulation requirements be established by taking diversity benefits into account. Diversity benefits result from aggregating the variations of all resources so that one resource's negative deviation can offset some or all of another resource's positive deviation. When the transactions of two customers result in diversity benefits, it is incorrect to say that one customer is benefitting the other but not vice versa. Instead, the diversity benefits result from both transactions and sharing of these benefits among the customers is reasonable. In *Westar*, the Commission found that this portfolio-wide approach to assessing generator regulation charges appropriately shares diversity benefits among generators and load.[324] Ultimately, this concept will need to be reconciled with any customer classifications proposed by the public utility transmission provider in a way that prevents any over-recovery of these capacity costs.

320. Third, to the extent a public utility transmission provider proposes to differentiate among customers (or customer classes) in determining their relative regulating reserve responsibilities, the public utility transmission provider must demonstrate that the overall quantity of regulating reserve it requires of its transmission customers accounts for diversity benefits among all resources and loads, and the allocations to individual customers (or customer classes) of their proportionate share is based on the operational characteristics of such customers (or customer classes).

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[324] *See Westar*, 130 FERC ¶ 61,215 at PP 37-38.

321. Fourth, weather events such as droughts may affect the required quantity of generator regulating reserves that the public utility transmission provider must have in reserve more or less during one portion of the year versus another portion of the year. In such cases, these diversity events, though perhaps characterized as anomalies, should be included in the data set so that the quantity and costs of such reserves are more reflective of actual system operations.

322. Fifth, there is a relationship between the use of intra-hour scheduling by transmission customers and the quantity of reserves needed to provide Schedule 9 generator imbalance service. In other sections of this Final Rule, the Commission requires all public utility transmission providers to offer transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals, noting that over time public utility transmission providers will be able to rely more on planned scheduling and dispatch procedures and less on reserves to maintain overall system balance. In the Proposed Rule, the Commission sought comment on whether to condition the ability of public utility transmission providers to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves on the implementation of intra-hour scheduling reforms. Given that such reforms are mandated in this Final Rule, the Commission concludes that condition to be satisfied.[325] In designing any proposals for

[325] *See supra* IV.A.1 (Intra-Hour Scheduling Requirement).

generator regulation service charges, a public utility transmission provider should consider the extent to which transmission customers are using intra-hour scheduling in evaluating whether to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves.

323. Sixth, there also is a relationship between the use of power production forecasting and the allocation of generator regulation reserve quantities to a particular class of customers. The record in this proceeding demonstrates that the quantity of reserves used to provide generator regulation service can be most efficiently managed with the implementation of power production forecasting (as well as intra-hour scheduling) by public utility transmission providers. While commenters disagree on the extent to which power production forecasting may affect reserve commitments, the Commission finds that power production forecasts can provide public utility transmission providers with advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than through the deployment of reserve services, such as regulation reserve. Without the increased situational awareness of projected variability provided by power production forecasts, the public utility transmission provider's ability to commit or de-commit resources providing regulation reserves efficiently can be constrained. This lack of situational awareness potentially can result in rates for generator regulation service that are unjust and unreasonable or unduly discriminatory.

324. We recognize that conditioning the allocation of different quantities of regulation reserves to different transmission customers on the public utility transmission provider

developing and deploying power production forecasting is contentious. On one hand certain public utility transmission providers believe that they should either be able to use historical data or make other approximations to establish the quantity of regulation reserves to be required of a given transmission customer or class of customers. On the other hand, transmission customers that are VERs contend that the Commission has not gone far enough and that additional reforms are necessary to ensure that VERs do not disproportionately bear the burden of the cost of regulating reserves. The Commission believes that public utility transmission providers need an effective opportunity to file for cost recovery, while VERs need assurance that they are not unduly assigned costs.

325. Accordingly, while the Commission reserves judgment as to the appropriate power production forecasting requirements for a particular public utility transmission provider, we expect that the implementation of power production forecasting will be addressed in any proposal to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves. For example, a public utility transmission provider could demonstrate that it is utilizing power production forecasts (or other comparable technique) to manage system operating costs and/or to improve reliability by enabling the more efficient commitment and dispatch of resources. The Commission agrees with the California PUC that, as part of such a demonstration, the public utility transmission provider should explain how the data required from VERs are incorporated into the power production forecast and how the resulting forecast is used to support the management of operating costs and/or reserves or otherwise ensure that capacity costs incurred to provide Schedule 9 service are prudently incurred.

326. The Commission declines to require the additional forecasting-related showings suggested by NaturEner and others. The technologies and techniques for power production forecasting are still being refined and may differ from region to region. While the recommendations made by AWEA, Iberdrola, and NaturEner may be appropriate benchmarks for power production forecasts utilizing today's technology, the Commission believes that pre-defining these additional criteria would not provide the flexibility needed for public utility transmission providers to adopt new forecasting techniques or technologies as they are developed. The Commission also declines to adopt the further recommendations of the California PUC and others to include monitoring and reporting requirements for public utility transmission providers that engage in power production forecasting. The Commission finds adopting these requirements to be unnecessary at this time.

327. However, the Commission agrees with Iberdrola and others that the public utility transmission provider should make the results of any centralized forecast used by the public utility transmission provider available through a secure information exchange to VER generators providing related data. The Commission believes that the VERs should be able to access the results of the public utility transmission provider's forecast in order to ensure that the forecasting service is producing accurate results. Thus, public utility transmission providers proposing to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves should explain in their proposals how forecasting results will be shared.

328. In response to comments regarding forecasting risk, the Commission clarifies that the transmission customer is responsible for the accuracy of transmission schedules and the public utility transmission provider is responsible for the reliability of its system. Therefore, the public utility transmission provider would utilize the power production forecast to identify the necessary amount of reserves and to use those reserves to maintain reliability of the transmission system. The obligation of the transmission customer is to submit schedules for deliveries. Power production forecasting is intended to inform the transmission provider regarding aggregate system variability that results from having VERs on its system, not to replace transmission schedules from transmission customers delivering from VERs. Public utility transmission providers using power production forecasts should do so to manage uncertainty in the same manner they use other forecasts of uncertainty for the transmission system. For example, despite service agreements to serve load, public utility transmission providers develop and use load forecasts to assure load can be met reliably and efficiently. Similarly, despite transmission schedules to deliver from a VER, public utility transmission providers should use power production forecasts to assure energy can be provided to load in a reliable and efficient manner.

329. Therefore, the Commission agrees with NorthWestern and others that the transmission customer maintains responsibility for the accuracy of its transmission schedule. However, we disagree with NorthWestern's interpretation concerning NERC Control Performance Standard 2 violations. A public utility transmission provider is not responsible for submitting a transmission schedule on behalf of a VER. As explained above, power production forecasting would be utilized to identify and acquire the

appropriate amount of reserves needed to integrate VERs reliably. Nothing in this Final Rule alleviates the public utility transmission provider's obligations under NERC Reliability Standards.

330. The Commission declines to require transmission customers delivering from a VER to submit transmission schedules according to the public utility transmission provider's forecast, as suggested by Bonneville Power. While the public utility transmission provider is able to forecast the *aggregate* variability of the system with greater accuracy through centralized power production forecasting, the individual VER may be better able to produce the most accurate schedule for its particular facility. Requiring a transmission customer to submit transmission schedules for VER deliveries according to a centralized forecast would cloud the delineation between the obligations of the VER and the obligations of the public utility transmission provider with respect to the provision of transmission service.

331. The Commission disagrees with Puget's example, and clarifies that the public utility transmission provider's obligation should be to deploy its resources according to its own forecast in order to maintain the reliability of the system. The public utility transmission provider retains the risk and responsibility for inaccurate procurement of reserve requirements while the transmission customer retains the financial risk and responsibility for inaccurate schedules. The Commission finds that the incentive to avoid Schedule 9 generator imbalance penalties and any relevant charges for generator regulation service provides sufficient incentive for VERs to submit an accurate schedule.

332. The Commission agrees with National Grid and others that, as the entity providing transmission service under an OATT, the ISO or RTO would engage in power production forecasting within its region. In response to Pacific Gas & Electric and others requesting flexibility to implement power production forecasting, the Commission finds that the guidance provided affords sufficient flexibility to allow public utility transmission providers to tailor their forecasting programs to meet their needs, whether for the purpose of developing proposals for generator regulation charges or otherwise.

333. The Commission emphasizes that the foregoing discussion is intended to provide a framework to assist public utility transmission providers in developing proposals for generator regulation service should they desire to do so. The Commission does not intend this guidance to preclude a public utility transmission provider from making an alternative proposal under section 205 of the FPA. However, it does provide guidance to public utility transmission providers regarding the facts and circumstances that the Commission may find relevant in evaluating such proposals.

334. A number of commenters challenged the Commission's proposal to condition proposals that require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves on performance of the activities discussed above. These arguments have largely been rendered moot by the Commission's decision not to adopt the Proposed Rule in that regard. Even as applied to the guidance provided above, the Commission disagrees that a future decision by the Commission to condition proposals that require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves on

the performance of certain actions would violate cost causation principles or otherwise would preclude public utility transmission providers from recovering prudently incurred costs. In reviewing any future proposal to allocate a greater quantity of capacity costs to a particular set of transmission customers, it would be reasonable for the Commission to consider whether the public utility transmission provider has taken steps to mitigate such costs. This does not mean, as some commenters imply, that the public utility transmission provider has no other means to recover its costs. The public utility transmission provider could continue to rely on existing rate mechanisms to recover reserve costs or may propose to require a uniform quantity of generation regulating reserves from all transmission customers that is commensurate with transmission customers' proportionate effect on net system variability and taking diversity benefits into account.

335. The Commission agrees with commenters that implementing other reforms, such as consolidating balancing authority areas or implementing an ancillary services market, may be beneficial to the reliable and efficient integration of VERs. However, the Commission is not persuaded that these additional reforms are a necessary precondition to proposals that require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves. As noted in the Proposed Rule, many of these additional reforms are being discussed in other forums. The Commission will continue to monitor these proposals as they develop and modify our approach to this issue as appropriate as conditions develop.

3. Use of Contingency Reserves

a. Commission Proposal

336. In the Proposed Rule, the Commission sought comments from NERC and industry stakeholders on the steps needed to resolve confusion regarding the use of contingency reserves to manage extreme ramp events of VERs.[326] The Commission also sought comments from NERC and industry stakeholders on the extent to which some additional type of contingency reserve service (beyond the services provided under Schedule 5 and 6 of the *pro forma* OATT) would ensure that VERs are integrated into the interstate transmission system in a non-discriminatory manner while remaining consistent with NERC Reliability Standards.[327]

b. Comments

337. NERC indicates that large wind ramping events are similar to conventional generator contingency events in that they are large and relatively infrequent, yet they differ in that wind ramps are much slower than instantaneous contingency events and may be possible to forecast. NERC states that the use of contingency reserves to address wind ramps is similar to what is used to address large, relatively infrequent wind ramps

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[326] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 100 (citing Schedule 5 (Operating Reserve – Spinning Reserve Service) and Schedule 6 (Operating Reserve – Supplemental Reserve Service) respond to contingency events. Spinning Reserve Service is used to serve load "immediately in the event of a system contingency" whereas Supplemental Reserve Service "is not available immediately to serve load but rather within a short period of time.")).

[327] *Id.* P 100.

because contingency reserves are seldom deployed, yet long ramp durations can make it difficult to include wind ramps as actual contingencies. NERC explains that Resource and Demand Balancing (BAL) Reliability Standard BAL-002 (Disturbance Control Performance) requires ACE to be restored 15 minutes following the disturbance (R4) and the contingency reserves to be restored within 105 minutes (90 minutes after the 15 minute disturbance recovery period – R6). NERC states that both of these requirements can be problematic for wind ramps because they can be longer than the disturbance recovery period as well as the reserve restoration period.

338. Still, NERC indicates that it may be appropriate to use contingency reserves in response to a portion of a wind ramp. NERC states that shared contingency reserves could be used to initiate the response, allowing time for alternate supply (or load reduction) to be implemented. NERC suggests that the industry consider developing rules governing reserve deployment and restoration, similar to those that currently address conventional contingencies.

339. Other commenters express openness to using contingency reserves for wind events.[328] Commenters indicate that there are discussions in the Northwest Power Pool (NWPP) about the use of contingency reserves for wind events.[329] AWEA contends that contingency reserves should be used for the initial period of an extreme wind ramp

[328] *E.g.*, Powerex; NaturEner; California PUC; MidAmerican.

[329] *E.g.*, Powerex; Tacoma Power.

because both contingency events and extreme wind ramp events are very infrequent, and therefore, the use of contingency reserves for extreme wind ramp events would be highly unlikely to coincide with a need to use those reserves for a conventional generator's contingency event. NextEra urges the Commission to convene a technical conference to address how to deploy contingency reserves to address ramp events in a manner that will promote reliability.

340. Xcel indicates that there is confusion regarding the use of contingency reserves to manage extreme ramping events. Xcel states that the confusion arises as entities attempt to define the allowable triggering events for the activation of contingency reserves. Xcel recommends that the standard for contingency reserve activation include disturbances related to less-than-anticipated VER (e.g., wind) production, sudden drop-off of VER production, or associated ramp limitations on balancing resources due to forecast errors. Xcel contends that ramp events related to VERs are not necessarily caused by the sudden failure of generation, but instead may be due to an incorrect wind forecast or limited dispatchable generation response. For these reasons, Xcel recommends: (1) expanding the definition of disturbances to include ramp events which may occur over a half-hour time frame; (2) including a measurement technique related to a ramp event in BAL-002; (3) identifying a specific restoration period in BAL-002 (e.g., 45 minutes) related to contingency reserves that were deployed for ramping events; and (4) identifying compliance metrics and other issues related to deployment of contingency reserves for ramp-limited events. Xcel recommends that the Commission request that NERC begin a

standards drafting process to consider revisions to the existing BAL-002 standard to address the issues discussed by Xcel.

341. Other commenters express reservations with using contingency reserves in response to wind events is an improper use of contingency reserves.[330] Duke indicates to the extent that there is a need for a new service to address VER ramp rates, a new rate schedule should be developed for such a service. Pacific Gas & Electric states that there may be a need for new integration services to incorporate VERs into the reliable operation of the grid. Pacific Gas & Electric submits that various industry activities are already underway to consider these issues, and the Final Rule should endorse their continued efforts.

c. Commission Determination

342. Based on comments received, the Commission concludes that the issues related to the appropriate use of contingency reserves under NERC Reliability Standards need further study and vetting before any action is considered. Indeed, comments range from expressing confusion over what would constitute an extreme VER event to asking the Commission to define "ramp" with some specificity. Rather than opining on any of the comments and risk providing guidance without the benefit of more information, the Commission finds that the better course of action is to allow industry to continue its work and direct our staff to monitor those efforts and engage industry as appropriate.

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[330] *E.g.*, Tacoma Power; ENBALA; Grant PUD; California ISO; Duke; Pacific Gas & Electric.

V. Other Issues

1. Regulatory Text

a. Commission Proposal

343. As part of the Proposed Rule, the Commission sought comment on a minor revision to 18 C.F.R. 35.28. To date, when amending its regulations concerning the open access requirements of the *pro forma* OATT, the Commission has listed by name Commission rulemaking proceedings promulgating and amending the *pro forma* OATT when explaining the details of a public utility transmission provider's obligation to have an OATT on file with the Commission. The Commission proposed to no longer explicitly reference, by name, prior Commission rulemaking proceedings promulgating and amending the *pro forma* OATT in its regulations. Likewise, the Proposed Rule included a similar change with respect to a public utility transmission provider's obligation to have standard generator interconnection procedures and agreements and standard small generator interconnection procedures and agreements on file with the Commission.[331]

b. Comments

344. No comments were received on this aspect of the Proposed Rule.

c. Commission Determination

345. The Commission adopts its proposed minor revision to 18 C.F.R. 35.28. We find that the existing process for amending regulations concerning the *pro forma* OATT, which necessitates listing by name Commission rulemaking proceedings promulgating

[331] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 12 & n.29.

and amending the *pro forma* OATT when explaining the details of a public utility transmission provider's obligation to have an OATT on file with the Commission, is increasingly cumbersome and provides little, if any, benefit. Thus, the Commission will no longer explicitly reference, by name, prior Commission rulemaking proceedings promulgating and amending the *pro forma* OATT in its regulations. Likewise, the Final Rule adopts a similar change with respect to a public utility transmission provider's obligation to have standard generator interconnection procedures and agreements and standard small generator interconnection procedures and agreements on file with the Commission.

2. Market Mechanisms

a. Comments

346. Several commenters ask the Commission to revise specific RTO and ISO market rules not at issue in the Proposed Rule, while other commenters seek to have the Commission address additional market mechanisms for the non-RTO and ISO areas. For example, Environmental Defense Fund states that the Proposed Rule does not reform the day-ahead market to increase VER participation and decrease the amount of costly out-of-market commitments, leading to unjust and unreasonable rates, and undue discrimination against VERs. In addition, ACSF asserts that scheduling in the day-ahead market and in the unit commitment process should be reformed. ACSF states that the technology that makes 15-minute schedules feasible in the spot market also makes reforms possible in these other areas. According to ACSF, it is important to prevent the

least clean and efficient generation from dominating dispatch at all hours, especially in the unit commitment process.

347. Environmental Defense Fund further states that because VERs are only permitted to bid a portion of their capacity into the market, they generally receive a lower price. According to Environmental Defense Fund, many capacity markets require bidders to also participate in the day-ahead market, which most VERs do not do because of the financial risk associated with failing to meet day-ahead obligations. Thus, Environmental Defense Fund argues that the Commission must consider the available options to facilitate VER participation in capacity markets.

348. With regard to non-RTO regions, EPSA states that the Proposed Rule does not sufficiently address the lack of market mechanisms available in non-RTO regions to conventional generation resources, which have the ability to contribute to VERs integration. EPSA suggests that possible market mechanisms and other competitive options for integrating VERs in the non-RTO regions should be considered as part of the technical conference that EPSA has requested. Similarly, Independent Power Producers Coalition–West states that without an organized ISO or RTO market, public utilities must face regulatory pressure to advance their integration of VERs and sharing of data, otherwise the utilities have little incentive to move toward better integration between transmission providers and balancing authorities. Independent Power Producers Coalition–West contends that the lack of a competitive ancillary services market that would allow independent power producers the opportunity to provide generator imbalance services in WECC results in unjust and unreasonable rates.

349. Tres Amigas contends that Order Nos. 888 and 890 have left little room for a market to develop balancing services outside of an ISO/RTO, because the primary provider of these services, the balancing authority, has to acquire the capability to provide the ancillary services on behalf of all its transmission customers and then sell the services at cost-based rates. Tres Amigas states that the Commission should have a two-fold objective: (1) determining how market forces can identify and competitively price the resources that will be used by balancing authorities for balancing; and (2) establishing appropriate mechanisms for allocating the costs incurred by balancing authorities to acquire these resources in the marketplace. Further, Tres Amigas asserts that the Commission should grant market-based rates to new entrants in order to promote formation of a vibrant market for balancing services that includes participation by new technologies. Tres Amigas states that the balancing authorities should then file proposals to allocate the costs incurred to balance the system among load and generation (including generation within the control area that is scheduled to another control area). According to Tres Amigas, these cost allocation proposals should take into account the extent to which different market participants contribute to the costs of acquiring balancing services and benefit from such services.

350. Recycled Energy urges the Commission to consider implementing various payments designed to compensate efficient gas generators and combined heat and power facilities for the flexibility they provide to utilities. In addition, Recycled Energy asserts that the Commission could improve the grid's reliability and efficiency by encouraging the placement of distributed generators in ways that reduce line losses and obtain

ancillary benefits. Similarly, Business Council asserts that the OATT should be revised to ensure that flexible resources (such as natural gas and pumped storage facilities) are better able to provide their services to system operators who integrate VERs, and that these services are properly valued. Business Council explains that flexible generation resources should be given more opportunities to sell their balancing services to transmission providers and should be paid a just and reasonable rate for these services. Business Council argues that if the Commission adopts a universal requirement for 15-minute scheduling, it should make clear that generators should be able to supply balancing services on the same 15-minute (or less) basis.

b. Commission Determination

351. The *pro forma* OATT terms and conditions of service create the platform by which the public utility transmission provider makes available non-discriminatory open, access transmission service. Since the issuance of Order No. 888, the Commission has taken numerous actions to ensure that the principles enunciated in that rule continue to remain true, allowing all types of resources – existing and new – access to the grid for the benefit of developing competitive markets. In response to commenters like Independent Power Producers-West, EPSA and Tres Amigas who assert that the Commission should take various steps to establish a competitive ancillary services market or other market mechanisms, we believe that the reforms in this Final Rule continue to facilitate the development of competitive markets without imposing any particular type of structure for doing so. The Commission allows third party sellers to make sales of ancillary services at market-based rates, requires all public utility transmission providers to offer open

access transmission service and undertake open and transparent transmission planning, and allows transmission customers to self-supply their own ancillary services. The Commission has long-standing precedent on cost allocation and has long supported reserve sharing and power pooling arrangements. Nothing in this rule is intended to prevent or create a barrier to the further development of competitive markets. Indeed, we think that the reforms adopted herein should help to facilitate the further development of competitive markets by allowing transmission customers to tailor their transmission schedules and, in turn, better manage generator imbalance and ancillary services costs. As the liquidity of intra-hour energy products stabilizes, market participants also may begin to commit or otherwise acquire fewer reserves in advance, with the knowledge that they can purchase additional reserves on an as-needed basis from third parties. Requiring public utility transmission providers to offer intra-hour scheduling is a necessary predicate to facilitate these market opportunities.

352. For similar reasons we decline the request from Recycled Energy and Business Council to expand the scope of this rulemaking proceeding to include additional payments to flexible generation. Both commenters urge the Commission to adopt mechanisms that would increase payments to flexible generation resources, such as high-efficiency natural gas facilities, so as to properly value the flexibility they provide to transmission providers. The Commission has already addressed, in the context of the organized markets, compensation for resources providing frequency regulation and is

currently exploring a similar issue in bilateral markets outside of RTOs and ISOs.[332] In this proceeding, the Commission is primarily concerned with providing reforms that will provide public utility transmission providers with greater awareness of the variability experienced on their systems, as well as providing transmission customers with a tool to manage imbalances from schedules by providing for 15-minute adjustments to schedules. How these public utility transmission providers choose to provide this service is beyond the scope of this inquiry.

353. With regard to commenters that request additional changes to the RTO and ISO day-ahead and capacity markets to facilitate VER integration, we fail to see the direct connection between the specific reforms of the Commission's Proposed Rule and the reforms requested. Commenters did not establish that connection and failed to demonstrate that the Commission's proposed reforms are unjust and unreasonable without the additional requested reforms. Instead, these commenters merely asked that the Commission extend the scope of the rule. As such, we find that commenters' requests that we require additional reforms to RTO/ISO day-ahead, residual unit commitment, and capacity market rules are beyond the scope of this proceeding.

[332] *See Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 76 FR 67260 (Oct. 31, 2011), FERC Stats. & Regs. ¶ 31,324 (2011); *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologi*es, 139 FERC ¶ 61,245 (NOPR).

354. Finally, we cannot allow sales of energy or capacity at unchecked rates, even by new entrants, as suggested by Tres Amigas.[333] As noted above, the Commission allows for sales at market-based rates upon a showing of lack of market power and is in the process of considering ways to streamline the market-based rate showing for certain ancillary services.[334]

c. Pipeline Transportation Nomination Procedures

i. Comments

355. Some commenters assert that if the Commission requires transmission providers to allow intra-hour transmission scheduling to accommodate VERs, the Commission must also consider the impact of such requirements on the operation of natural-gas-fired electric generation units, and the concomitant need to modify pipeline transportation service nomination procedures to calibrate gas transportation and usage more closely with the operation of natural gas-fired electric generation units to support VERs.[335] Specifically, APPA contends that despite access to real-time electronic metering and flow control and technological advances that enable the electronic submission of gas nominations, the current time period used to process pipeline transportation service

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[333] *See Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, Order No. 697, 72 FR 39904 (July 20, 2007), FERC Stats. & Regs. ¶ 61,295, at P 320 (2007).

[334] *See Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologi*es, 139 FERC ¶ 61,245 (NOPR).

[335] *E.g.*, Joint Parties; TVA; Midwest Energy; APPA.

nominations and to schedule natural gas is the same time period (up to 4 hours) that was adopted over a decade and a half ago. APPA notes that this already substantial disconnect between the nomination and scheduling procedures used in the natural gas and electric power industries will only become more severe if intra-hour scheduling is adopted. Similarly, Joint Parties request that the Commission open a companion docket to examine barriers that may exist in the natural gas industry that inhibit the timely access to natural gas that is needed to ensure the seamless integration of VERs.[336]

356. American Gas and INGAA state that gas transmission systems have developed innovative services to accommodate the needs of gas-fired generators to access gas supplies quickly in response to electric system dispatch orders. American Gas and INGAA explain that these offerings demonstrate that individual, tailored solutions may better address gas-electric coordination concerns than a modification of the gas nomination schedule. For this reason, American Gas encourages the Commission to continue to be open to creative market solutions to meet the needs of gas-fired generators in ways that do not unnecessarily affect existing shippers in adverse ways. American Gas also encourages the Commission to hold a technical conference or other non-NAESB forum to discuss ways in which the natural gas and electric industries can work together.

[336] TVA contends that the Commission should reevaluate its policy of not allowing a firm gas transportation holder to take precedence over (i.e., bump) a non-firm customer, because gas-fired generators paying for firm gas transportation service must be able to support electric needs in general and in integrating VERs specifically.

357. American Gas further contends that the Commission's consideration of gas-electric coordination issues should not focus narrowly on the gas nomination and scheduling cycle as a primary solution to the reliability issues which both industries face. While American Gas believes that a single, nationwide gas nomination schedule is essential to the efficient functioning of the natural gas system, a modification to that schedule alone is not the most effective means to address gas-electric coordination issues.

358. AEP adds that while the proposed scheduling option appears on the surface to be feasible within the power industry, the increased quantity of VERs and subsequent increased ramping capability requirements will further exacerbate the operational difficulties associated with the varied scheduling timelines existing between the gas and power industries. AEP concludes that such discrepancies place the gas-fired generation operators, whose typically superior ramping capabilities will become increasingly beneficial, in a position of speculating on fuel supply needs because they are unsure whether the increase in variable generation will mean an increased need for the faster ramping capabilities of gas.

359. AEP notes that these differences have existed for many years, and managing them has become more challenging with the introduction of RTO-administered markets, as unit commitment is generally made by the RTO, and not the individual asset owner. AEP argues that any proposed scheduling practices related to incremental VER penetration must account for such inter-market dependencies.

360. Spectra Entities notes that the interface issues between the gas and electric industries go beyond revisiting coordinating and the gas/electric scheduling timelines.

Spectra Entities argues that there are regulatory policy and market barriers discouraging the electric industry in some markets from contracting for adequate firm gas supply and firm transportation arrangements to serve those generators which must run in order to maintain the reliability of the electric grid. For example, the Commission's "no-bump" policy and the need to coordinate scheduling of interruptible services are irrelevant during peak or high load days in natural gas markets, because interruptible capacity is rarely available on the pipeline grid under those conditions. Spectra Entities argue that unless these barrier issues are addressed, any changes to coordination and scheduling or the offering of innovative transportation solutions will not be sufficient to achieve the Commission's goals.

ii. Commission Determination

361. While comments asking the Commission to undertake reforms to natural gas pipeline rules and procedures in order to facilitate greater cross-market coordination are beyond the scope of this proceeding, we agree that the interdependence of these two industries merits careful attention. The Commission has recently addressed proposed changes to the gas pipeline nomination procedures. In the past, the Commission has urged the industry, working through NAESB, to consider changes to its nomination procedures to provide better coordination between gas and electric scheduling.[337] More

[337] *See Standards for Business Practices for Interstate Natural Gas Pipelines: Standards for Business Practices for Public Utilities*, Order No. 698, FERC Stats, & Regs ¶ 31,251, at P 69 (2007).

recently, in Order No. 587-U, the Commission acknowledged that NAESB lacked consensus to implement any such changes and did not find a nationwide scheduling solution in response to concerns over gas pipeline nomination procedures (including the "no-bump" rule).[338] While eschewing nationwide changes, Order No. 587-U emphasized that "individual pipelines may be able to offer special services or increased nomination opportunities that better fit the profile of gas-fired generation."[339] In fact, some pipelines have begun to offer special services to facilitate the flexibility needs of gas-fired generation.[340]

362. On March 30, 2012, a number of entities submitted further comments on gas-electric coordination issues in response to a notice issued in Docket No. AD12-12-000 that requested comments in response to a set of questions and other text concerning gas-electric interdependence issued by Commissioner Moeller on February 3, 2012. The Commission is currently evaluating these comments to determine what, if any, additional steps would be appropriate to take to facilitate coordination between the gas and electric industries.

[338] Order No. 587-U, FERC Stats. & Regs. ¶ 31,307 at P 27.

[339] *Id.*

[340] *See Texas Gas Transmission LLC*, 138 FERC ¶ 61,176 (2012).

3. Power Factor Design

a. Comments

363. Midwest ISO Transmission Owners state that Order No. 661 exempted wind generators from having to maintain power factor design criteria absent a specific finding in the relevant system impact study that the generator needs to maintain a specific power factor in order to ensure safety and reliability. Midwest ISO Transmission Owners submit that the Commission should convene a technical conference to examine this issue, or allow individual transmission providers to file to eliminate this exemption from their *pro forma* LGIAs or generator interconnection agreements. Midwest ISO Transmission Owners explain that wind and other VERs have obtained significant penetration levels in many areas of the country, such that wind is no longer a new technology that needs protection. Midwest ISO Transmission Owners contend that eliminating this exemption will ensure that wind does not receive an unfair competitive basis.

b. Commission Determination

364. Since issuance of the Proposed Rule in this proceeding, the Commission has directed staff to convene a technical conference in Docket No. AD12-10-000 to examine whether the Commission should reconsider or modify the reactive power provisions of Order No. 661-A and examine what evidence could be developed under Order No. 661 to support a request to apply reactive power requirements more broadly than to individual

wind generators during the interconnection study process.[341] The Commission concludes that potential issues regarding the exemption provided under Order No. 661-A are better addressed in that proceeding.

VI. Compliance

A. Commission Proposal

365. In the Proposed Rule, the Commission indicated that each public utility transmission provider must submit a compliance filing within six months of the effective date of the Final Rule revising its OATT and LGIA to demonstrate compliance with the Final Rule. The Commission indicated that to demonstrate compliance, a public utility transmission provider must file: (1) revisions to its OATT to implement 15-minute scheduling; (2) revisions to its LGIA to include a requirement for interconnection customers whose generating facility is a VER to provide data to the public utility transmission provider when the public utility transmission provider is developing and deploying power production forecasting for VERs; and (3) the addition of Schedule 10 to the OATT, which includes the same per unit rate from their currently effective Schedule 3, and a blank or unfilled volumetric component, among other things.

366. The Commission acknowledged that public utility transmission providers may have provisions in their existing OATTs and LGIAs that the Commission has deemed to be consistent with or superior to the *pro forma* OATT and LGIA. The Commission

[341] *Reactive Power Resources*, Notice of Technical Conference, Docket No. AD12-10-000 (issued Feb. 17, 2012).

indicated that where these provisions are being modified by the Final Rule, public utility transmission providers must either comply with the Final Rule or demonstrate that these previously-approved variations continue to be consistent with or superior to the *pro forma* OATT and LGIA as modified by the Final Rule.

367. The Commission also proposed that transmission providers that are not public utilities would have to adopt the requirements of the Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[342]

B. Comments

368. Commenters addressing the six month timeframe generally argue that the proposed compliance deadline does not provide enough time for the industry to implement intra-hour scheduling effectively.[343] Specifically, commenters assert that additional time is needed to allow transmission providers time to: (1) develop necessary revisions to inter-regional agreements and procedures, and finish ongoing pilot programs; and (2) evaluate all potential impacts to operations and address issues regarding reliability via NERC, and perhaps business standards via NAESB.

369. Southern California Edison argues that regional differences and the need to implement intra-hour scheduling efficiently require careful consideration of each region's

[342] Order No. 888, FERC Stats. & Regs. at 31,760-763.

[343] *E.g.*, MidAmerican; EEI; FriiPwr; NRECA; Southern California Edison; Pacific Gas & Electric; Grant PUD; NextEra; PNW Parties; Powerex; NV Energy; New York ISO; ISO/RTO Council.

scheduling rules. Specifically, Southern California Edison suggests that the Commission provide three years to implement 30-minute scheduling followed by an 18-24 month evaluation period before deciding if 15-minute intra-hour scheduling is necessary. Pacific Gas & Electric recommends that the Commission lengthen the implementation timeline for intra-hour scheduling, so that regional technical conferences on intra-hour scheduling can be convened for affected transmission providers, and so that ongoing pilot studies on intra-hour scheduling may be completed.

370. NorthWestern comments that six months is insufficient time for a compliance filing implementing the intra-hour scheduling requirements of the Proposed Rule. NorthWestern argues that compliance will include, but not be limited to, implementation of software and hardware upgrades, adoption of common regional scheduling practices in the region with jurisdictional and non-jurisdictional balancing authorities, and hiring and properly training of additional staff. NorthWestern encourages the Commission to be flexible and allow balancing authorities the ability to define implementation timeframes, perhaps up to one year before the compliance filing is due.

371. Commenters also point more generally to areas of the Proposed Rule that may require additional time for compliance. Midwest ISO Transmission Owners state for example that additional time may be needed to make changes that are highly technical or require an extensive stakeholder process to implement.[344] Midwest ISO suggests that at

[344] Midwest ISO Transmission Owners at 16.

least 18 months should be allotted for transmission providers to submit compliance filings revising their OATT, LGIA, or other documents.[345] MidAmerican recommends that sufficient time be allocated so that transmission providers may (1) evaluate and address all potential impacts to operations and reliability and (2) be afforded the necessary time to procure resources, develop and adopt administrative processes, conduct training, and perform testing and validation critical to successfully effectuate the proposed reforms.

372. EEI suggests that the Commission not require the changes set forth in the Proposed Rule until the regional planning and cost allocation Final Rules have gone through any rehearing and legal challenges that may develop. On the other hand, Iberdrola supports the Commission's proposal to require a compliance filing within six months; however, if the Commission extends the deadline, Iberdrola recommends that implementation of Schedule 10 occur coincidentally with the implementation of the other two proposed operational changes.

C. Commission Determination

373. The Commission extends the deadline for compliance filings by 6 months so that public utility transmission providers will have 12 months from the effective date of this Final Rule to submit their compliance filings. The Commission also provides the *pro forma* tariff language that public utility transmission providers must include in their

[345] Midwest ISO at 15.

OATTs and LGIAs, with modifications to the language based upon the comments received, as discussed within the body of this Final Rule.[346]

374. Consistent with the discussion in the intra-hourly scheduling section, the Commission requires public utility transmission providers to revise their OATTs to provide an opportunity for transmission customers to submit transmission schedules at 15-minute intervals within 12 months of the effective date of this Final Rule.[347] Public utility transmission providers with provisions in their existing OATTs that the Commission has deemed to be consistent with or superior to the *pro forma* OATT being modified by the Final Rule can seek to demonstrate in their compliance filings that those previously-approved variations continue to be consistent with or superior to the *pro forma* OATT as modified by the Final Rule. In addition, public utility transmission providers may submit alternative proposals that are consistent with or superior to the intra-hour scheduling requirements of this Final Rule and are otherwise just and reasonable and not unduly discriminatory or preferential.[348] .

375. Consistent with the discussion in the data reporting section, the Final Rule modifies the compliance obligation set forth in the Proposed Rule and requires public

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[346] *See* Appendix A and B for the adopted *pro forma* OATT and LGIA provisions consistent with this Final Rule.

[347] *See* Appendix A for the revised section 13.8 and 14.6 of the *pro forma* OATT provisions consistent with this Final Rule. As *noted supra* § IV.A.1 (Intra-Hour Scheduling Requirement), the implementation of 15-minute scheduling will only apply to intertie transactions in organized wholesale energy markets.

[348] *See supra* § IV.A.1 (Intra-Hour Scheduling Requirement).

utility transmission providers to modify their *pro forma* LGIAs to effectuate the data reporting requirement within 12 months of the effective date of this Final Rule rather than the six months initially proposed.[349] The Commission adopts proposed Article 8.4 of the *pro forma* LGIA, as modified per the discussion in the data reporting section. The Commission also adopts the proposed definition of VER. The Commission appreciates that public utility transmission providers in some regions, including RTOs and ISOs, have already implemented meteorological or forced outage reporting under relevant tariffs, business practices and/or markets rules. Such public utility transmission providers may seek to demonstrate in their compliance filings how continued use of these existing tariffs, business practices and/or market rules is adequate to satisfy the requirements of this Final Rule using the independent entity variation standard set forth in Order No. 2003, if relevant, or by demonstrating variations from the *pro forma* OATT are consistent with or superior to the requirements of this Final Rule.[350]

376. The Commission concludes that 12 months is a reasonable amount of time to implement the requirements of this Final Rule. Many public utility transmission providers have already implemented some form of sub-hourly scheduling, resolving many of the issues that must be addressed in order to accept transmission schedules on a

[349] *See* Appendix B for the revisions to the *pro forma* LGIA consistent with this Final Rule. Specifically, a new Article 8.4 and a new definition in Article 1 have been added to the *pro forma* LGIA and conforming revisions have been made to the table of contents.

[350] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 910.

15-minute interval. Twelve months also is an adequate amount of time for public utility transmission providers to determine the extent to which meteorological and forced outage data are necessary to support power production forecasting. Although we are extending the compliance deadline to 12 months from the compliance schedule in the Proposed Rule, we do not believe that more than 12 months will be necessary. Therefore, we will not extend the compliance deadline beyond 12 months, nor will we adopt commenters' other proposed recommendations.

377. Finally, the Commission also adopts the proposal that transmission providers that are not public utilities must adopt the requirements of the Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[351]

VII. Information Collection Statement

378. The Office of Management and Budget (OMB) regulations require approval of certain information collection and data retention requirements imposed by agency rules.[352] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

[351] Order No. 888, FERC Stats. & Regs. at 31,760-63.

[352] 5 C.F.R. 1320.11(b).

379. The Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[353] In the Proposed Rule, the Commission solicited comments on the need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. The Commission also included a table that listed the estimated public reporting burdens for the proposed reporting requirements, as well as a projection of the costs of compliance for the reporting requirements.

380. The Commission did not receive any comments specifically addressing the burden estimates provided in the Proposed Rule. However, commenters did respond to questions in the NOPR regarding the specific hardware, software, and personnel changes that are necessary to implement intra-hour scheduling. As noted in Section IV above, some parties argue that the cost to implement intra-hour scheduling will be modest, while other commenters state that implementation costs may be significant. In addition to the Commission's responses to the comments previously provided, the Commission believes that the revised burden estimates below are representative of the average burden on respondents.

[353] 44 U.S.C. 3507(d).

381. In the Final Rule, the Commission adds two burden categories that were not included in the Proposed Rule burden estimates. First, the Commission includes a burden estimate for transmission providers who choose to share power production forecast results with VERs. Second, the Commission includes a burden estimate for transmission providers who choose to voluntarily share VER-provided meteorological and forced outage data with third parties. Neither of these additional categories is required under the Final Rule. However, the Commission assumes that all Transmission Providers will implement these changes for the purposes of calculating a burden estimate. The Commission also notes that certain VERs will have increased burden due to submission of intra-hour schedules to transmission providers. However, the Commission assumes that only VERs who choose to participate in intra-hour scheduling are those who will receive at least as much benefit as the cost that must be expended. For this reason, the Commission is not including a burden estimate for this category in the table below.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the requirements contained in this Final Rule follow.

Data Collection FERC 516 (as contained in Final Rule in RM10-11)	Number and Type of Respondents [1]	Number of Responses Per Respondent [2]	Hours per Response [3]	Total Annual Hours [1 X 2 X 3]
Conforming tariff changes to require intra-hourly scheduling, waiver, or deviation request; and rate treatment terms for Ancillary Service	142[354] Transmission providers	1	8 first year only	1,136 first year only
Implementation of intra-hourly scheduling	142 Transmission Providers	1	30 reoccurring	4,260 reoccurring
Conforming changes to LGIA[355]	142 Transmission Providers	1	20 first year only	2,840 first year only
Sharing of power production forecasting results with VER	142 Transmission Providers	1	30 reoccurring	4,260 reoccurring
Sharing of VER provided meteorological and forced outage data with third party entities (e.g. NOAA, balancing authority area)	142 Transmission Providers	1	30 reoccurring	4,260 reoccurring

[354] The Commission estimated in the NOPR that 134 transmission providers would have additional burdens due to the Proposed Rule. Since then, the Commission has identified eight additional transmission providers who are non-public utilities that file reciprocity open access transmission tariffs that are also expected to voluntarily comply with this rule.

[355] Consistent with the approach taken in Order No. 2003, public utility transmission providers with power production forecasting systems in place via tariff provisions and/or other mechanisms will be required to demonstrate that deviations from the *pro forma* LGIA are consistent with or superior to the *pro forma* LGIA.

Data Collection FERC 516 (as contained in Final Rule in RM10-11)	Number and Type of Respondents [1]	Number of Responses Per Respondent [2]	Hours per Response [3]	Total Annual Hours [1 X 2 X 3]
Provision of meteorological and forced outage data to public utility transmission providers for use in power production forecasting[356]	160[357] Interconnection Customers with VERs per year	1	60 reoccurring	9,600 reoccurring
Totals				26,356[358] first year + reoccurring 22,380[359] subsequent years

Cost to Comply: The Commission has projected the total cost of compliance to be $3,004,584 in the first year, and $2,551,330 each year after.

Total Annual Hours in the first year (26,356 hours) @ $114 an hour [average cost of attorney ($200 per hour), consultant ($150), technical ($80), and administrative support ($25)] = $3,004,584.

Total Annual Hours in subsequent years (22,380 hours) @ $114 an hour = $2,551,320.

[356] Once a data exchange is implemented, the Commission expects that this process will be automated and require little to no day to day burden.

[357] The Commission estimates that there will be approximately 160 VERs that will sign an LGIA each year during the period from July 2012- July 2015 potentially subject to this requirement. This update from the NOPR represents more recent data.

[358] First year hours total 26,356, the sum of first year and reoccurring hours.

[359] Annual hours total 22,380, the sum of all reoccurring hours.

Title: FERC-516, Electric Rate Schedules and Tariff Filings

Action: Proposed Collection.

OMB Control No. 1902-0096

Respondents for this Rulemaking: Transmission Providers (an RTO or ISO also may file some materials on behalf of its members) and Variable Energy Resources.

Frequency of Information: As indicated in the table.

Necessity of Information: The Federal Energy Regulatory Commission is adopting these amendments to the *pro forma* OATT to remedy operational challenges related to the increased integration of VERs to the bulk electric system. The purpose of this Final Rule is to strengthen the *pro forma* OATT, so VERs can be reliably and efficiently integrated into the electric grid and to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. This Final Rule seeks to achieve this goal by amending the *pro forma* OATT and LGIA to incorporate provisions that require intra-hourly transmission scheduling and require interconnection customers whose generating facilities are VERs to provide meteorological and operational data to public utility transmission providers for the purpose of power production forecasting. The Commission also provides guidance regarding the development of proposals for generator regulation service.

Internal Review: The Commission has reviewed the proposed changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of

internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

382. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax (202) 395-7285]. Due to security concerns, comments should be sent electronically to the following e-mail address: oira_submission@omb.eop.gov. Comments submitted to OMB should include OMB Control No. 1902-0096 and Docket No. RM10-11-000.

VIII. Environmental Analysis

383. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[360] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Proposed Rule

[360] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[361]

IX. Regulatory Flexibility Act Analysis

384. The Regulatory Flexibility Act of 1980 (RFA)[362] generally requires a description and analysis of Final Rules that will have a significant economic impact on a substantial number of small entities. This Final Rule applies to public utilities that own, control or operate interstate transmission facilities[363] and to variable energy resources. The total estimated number of small public utility transmission providers[364] impacted by this Final Rule is estimated to be ten. The Commission assumes that the Final Rule will impact all the applicable small transmission providers equally at an average cost of $13,500 per year. The Commission does not consider this to be a significant economic impact. In

[361] 18 C.F.R. 380.4(a)(15) (2010).

[362] 5 U.S.C. 601-612 (2006).

[363] Other than those that have received waiver of the obligation to comply with Order Nos. 888, 889, and 890.

[364] A "small entity" as referenced in the RFA refers to the definition provided in section 3 of the Small Business Act where a firm is "small" if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

any event, each of these entities may seek waiver of these requirements.[365] The Commission estimates that all of the applicable VERs (160 per year) are small. Of these 160 entities, approximately 100 that are greater than 20 MW will be required to comply with the Final Rule and approximately 60 that are 20 MW or less will have the option to comply with the rule. The Commission estimates that each VER will have an average cost of $6,800 per year because of the Final Rule. The Commission does not consider this to be a significant economic impact on these small entities. The costs incurred by VERs due to this rule are offset by an expected reduction in energy imbalance penalties that will be assessed to VERs in the future due to improved forecasting and reduced uncertainty across 15-minute scheduling periods compared to hour-long scheduling periods. Accordingly, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

X. Document Availability

385. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business

[365] The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889, and 890.

hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

386. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

387. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

XI. Effective Date and Congressional Notification

388. These regulations are effective [insert date 60 days after publication in the **FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit this Final Rule to both houses of Congress and the Government Accountability Office.

List of subjects in 18 C.F.R. Part 35

Electric power rates
Electric utilities
Reporting and record-keeping requirements

By the Commission. Commissiner LaFleur is dissenting in part with a separate statement attached.
Commissioner Clark voting present.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 71-7352.

2. Amend § 35.28 as follows:

a. Paragraphs (c)(1) through (c)(1)(iii) are revised.

b. Paragraphs (c)(1)(v) and (c)(1)(vi) are revised.

c. Paragraphs (c)(3) and (c)(3)(ii) are revised.

d. Paragraphs (c)(4) through (c)(4)(ii) are revised.

e. Paragraph (d) is revised.

f. Paragraphs (d)(1) and (d)(2) are deleted.

g. Paragraphs (e)(1) and (e)(1)(ii) are revised.

h. Paragraphs (f)(1) and (f)(1)(i) are revised.

i. Paragraphs (f)(1)(ii) through (f)(1)(iv) are deleted.

j. Paragraph (f)(3) is revised.

k. Paragraphs (f)(3)(i), (f)(3)(ii), and (f)(4) are deleted.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c) Non-discriminatory open access transmission tariffs.

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission an open access transmission tariff of general applicability for transmission

services, including ancillary services, over such facilities. Such tariff must be the *pro forma* tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv), and (c)(1)(v) of this section, the open access transmission tariff, which tariff must be the *pro forma* tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff, and accompanying rates must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, it must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission

service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(v) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the open access transmission tariff required by this section.

(vi) Any public utility that seeks a deviation from the *pro forma* tariff promulgated by the Commission, as amended from time to time, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the *pro forma* tariff promulgated by the Commission, as amended from time to time, or such other open access transmission tariff as may be approved by the Commission consistent

with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before May 14, 2007, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the *pro forma* tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access transmission tariff is consistent with or superior to the *pro forma* tariff promulgated by the Commission, as amended from time to time, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(d) Waivers. A public utility subject to the requirements of this section and Order No. 889, FERC Stats. & Regs. ¶ 31,037 (Final Rule on Open Access Same-Time Information System and Standards of Conduct) may file a request for waiver of all or part of the requirements of this section, or Part 37 (Open Access Same-Time Information System and Standards of Conduct for Public Utilities), for good cause shown. Except as provided in paragraph (f) of this section, an application for waiver must be filed no later than 60 days prior to the time the public utility would have to comply with the requirement.

* * * * *

(e) Non-public utility procedures for tariff reciprocity compliance.

(1) A non-public utility may submit an open access transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(ii) If the submittal is found to be an acceptable open access transmission tariff, an applicant in a Federal Power Act (FPA) section 211 or 211A proceeding against the non-public utility shall have the burden of proof to show why service under the open access transmission tariff is not sufficient and why a section 211 or 211A order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access transmission tariff, for good cause shown. An application for waiver may be filed at any time.

(f) Standard generator interconnection procedures and agreements.

(1) Every public utility that is required to have on file a non-discriminatory open access transmission tariff under this section must amend such tariff by adding the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, or such other interconnection procedures and agreements as may be required by Commission rulemaking proceedings promulgating and amending the standard

interconnection procedures and agreement and the standard small generator interconnection procedures and agreement.

(i) Any public utility that seeks a deviation from the standard interconnection procedures and agreement or the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements.

* * * * *

(3) A public utility subject to the requirements of this paragraph may file a request for waiver of all or part of the requirements of this paragraph, for good cause shown.

Note: The following appendices will not be published in the Code of Federal Regulations.

Appendix A: List of Short Names of Commenters on the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking on Integration of Variable Energy Resources—Docket No. RM10-11-000, November 2010

Short Name or Acronym	Commenter
A123	A123 Systems, Inc.
AEP	American Electric Power Service Corporation
ALLETE	ALLETE Inc.
ACSF	American Clean Skies Foundation
Alstom	Alstom Grid, Inc.
American Gas	American Gas Association
APPA	American Public Power Association
Argonne National Lab	Argonne National Laboratory
Arizona Corporation Commission	Arizona Corporation Commission
Avista	Avista Corporation
AWEA	American Wind Energy Association
Beacon Power	Beacon Power Corporation
Bonneville Power	Bonneville Power Administration
BP Companies	BP Energy Company and BP Wind Energy North America, Inc.
BrightSource	BrightSource Energy, Inc.
Business Council	Business Council for Sustainable Energy
CESA	California Energy Storage Alliance

California State Water Project	California Department of Water Resources State Water Project
California ISO	California Independent System Operator Corporation
California PUC	California Public Utilities Commission
CEERT	Center for Energy Efficiency and Renewable Technologies
Center for Rural Affairs	Center for Rural Affairs
CMUA	California Municipal Utilities Association; Cities of Alameda, Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Corona, Glendale, Gridley, Healdsburg, Hercules, Lodi, Lompoc, Moreno Valley, Needles, Palo Alto, Pasadena, Pittsburg, Rancho Cucamonga, Redding, Riverside, Roseville, Santa Clara, Shasta Lake, Ukiah, and Vernon; the Imperial, Merced, Modesto, and Turlock Irrigation Districts; the Northern California Power Agency; Southern California Public Power Authority; Transmission Agency of Northern California; Lassen Municipal Utility District; Power and Water Resources Pooling Authority; Sacramento Municipal Utility District; the Trinity and Truckee Donner Public Utility Districts; the Metropolitan Water District of Southern California; and the City and County of San Francisco, Hetch-Hetchy
Clean Line	Clean Line Energy Partners, LLC
CGC	Coalition for Green Capital
Defenders of Wildlife	Wilderness Society and Defenders of Wildlife
Detroit Edison	Detroit Edison Company
Dominion	Dominion Resources Services, Inc.

Duke	Duke Energy Corporation
EEI	Edison Electric Institute
ELCON	Electricity Consumers Resource Council
EPSA	Electric Power Supply Association
ENBALA	ENBALA Power Networks
Entergy	Entergy Services, Inc.
Environmental Defense Fund	Environmental Defense Fund
E.ON C&R	E.ON Climate & Renewables North America
Exelon	Exelon Corporation
Federal Trade Commission	Federal Trade Commission
FirstEnergy	FirstEnergy Service Company
First Wind	First Wind Energy, LLC
FriiPwr	FriiPwr USA Ltd
Grant PUD	Public Utility District No. 2 of Grant County, Washington
Grays Harbor PUD	Public Utility District No. 1 of Grays Harbor County, Washington
Iberdrola	Iberdrola Renewables, Inc.
Idaho Power	Idaho Power Company
Independent Energy Producers	Independent Energy Producers Association
Independent Power Producers Coalition-West	Arizona Competitive Power Alliance; Colorado Independent Energy Association; Independent Energy Producers Association (California); New Mexico Independent Power Producers Coalition; and the Northwest &

	Intermountain Power Producers Coalition.
INGAA	Interstate Natural Gas Association of America
Invenergy Wind	Invenergy Wind Development LLC
ISO New England	ISO New England Inc. and the New England Power Pool
ISO/RTO Council	Alberta Electricity System Operator; California Independent System Operator; Electric Reliability Council of Texas; Independent Electricity System Operator of Ontario; ISO New England, Inc.; Midwest Independent Transmission System Operator, Inc.; New Brunswick System Operator; New York Independent System Operator, Inc.; PJM Interconnection, L.L.C.; and Southwest Power Pool, Inc.
ITC Companies	ITC*Transmission*; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; and ITC Great Plains, LLC
Joint Parties	Arizona Public Service Company; The Boeing Company, El Paso Electric; New York Independent System Operator; Old Dominion Electric Cooperative; PJM Interconnection, L.L.C.; Salt River Project Agriculture Improvement and Power District; Southwest Power Pool; Tennessee Valley Authority; Tucson Electric Power Company; UNS Gas, Inc.; and the Vermont Department of Public Service
Joint Initiative	Joint Initiative Facilitators
Large Public Power Council	Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities, Colorado Springs Utilities; CPS Energy (San Antonio); ElectriCities of North Carolina; Grant County Public Utility District; IID Energy (Imperial

	Irrigation District); JEA (Jacksonville, FL); Long Island Power Authority; Los Angeles Department of Water and Power; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District; New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; and Tacoma Public Utilities
LADWP	Department of Water and Power of the City of Los Angeles
Massachusetts DPU	Massachusetts Department of Public Utilities
MidAmerican	MidAmerican Energy Holdings Company
Midwest Energy	Midwest Energy, Inc.
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
Midwest ISO Transmission Owners	Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri; Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Duke Energy Corporation for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc. (“Hoosier”); Indiana Municipal Power Agency; Indianapolis Power & Light Company (“IPL”); Michigan Public Power Agency; MidAmerican Energy Company; Minnesota Power (and its subsidiary

	Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc. ("Xcel Energy"); NorthWestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.
M-S-R Public Power Agency	Modesto Irrigation District; City of Santa Clara, California; and City of Redding, California
Montana PSC	Montana Public Service Commission
NEMA	National Electrical Manufacturers Association
National Grid	National Grid USA
NRECA	National Rural Electric Cooperative Association
Natural Gas	Natural Gas Supply Association
NaturEner	NaturEner USA, LLC
NE Conference of PUCs	New England Conference of Public Utilities Commissioners
NESCOE	New England States Committee on Electricity
NV Energy	Nevada Power Company and Sierra Pacific Power Company
New York ISO	New York Independent System Operator, Inc.
NextEra	NextEra Energy, Inc.
NERC	North American Electric Reliability

	Corporation
NAESB	North American Energy Standards Board
NOAA	National Oceanic and Atmospheric Administration
NorthWestern	NorthWestern Corporation
Organization of Midwest ISO States	Organization of Midwest ISO States
Oregon & New Mexico PUC	Public Utility Commissioners of Oregon and New Mexico and Paul Newman, Arizona Commissioner
Pacific Gas & Electric	Pacific Gas and Electric Company
PNW Parties	Avista Corporation; the Bonneville Power Administration; Idaho Power Company; NorthWestern Corporation, dba NorthWestern Energy; PacifiCorp; Portland General Electric Company; the Public Generating Pool (Tacoma Power, Eugene Water and Electric Board, and Public Utility Districts for Chelan, Clark, Cowlitz, Douglas, Grant, Klickitat, Pend Oreille, and Snohomish counties); the Public Power Council; Puget Sound Energy, Inc.; and Seattle City Light
PJM	PJM Interconnection, L.L.C.
Powerex	Powerex Corporation
Public Interest Organizations	Alliance for Clean Energy New York; Center for Rural Affairs; Citizens Utility Board of Wisconsin; Climate and Energy Project; Conservation Law Foundation; Defenders of Wildlife; Energy Conservation Council of Pennsylvania; Energy Future Coalition; Environment Northeast; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; Great Plains Institute; Natural Resources Defense Council; Office of the Ohio

	Consumers' Counsel; Pace Energy and Climate Center; Project for Sustainable FERC Energy Policy; Sierra Club; The Wilderness Society; Union of Concerned Scientists; Western Grid Group; Western Resource Advocates; and Wind on the Wires
Public Power Council	Public Power Council
Puget	Puget Sound Energy, Inc.
Recycled Energy	Recycled Energy Development
RENEW	Renewable Energy New England, Inc.
RenewElec	The RenewElec Project
SMUD	Sacramento Municipal Utility District
San Diego Gas & Electric	San Diego Gas & Electric Company
Snohomish County PUD	Public Utility District No. 1 of Snohomish County, Washington
SEIA	Solar Energy Industries Association and the Large-Scale Solar Association
Southern California Edison	Southern California Edison Company
Southern	Southern Company Services, Inc.
Southern MN Municipal	Southern Minnesota Municipal Power Agency
SWEA	Southwest Energy Alliance
Southwestern	Southwestern Power Administration
Spectra Entities	Spectra Energy Transmission, LLC and Spectra Energy Partners, LP
Sunflower and Mid-Kansas	Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC

TA Miller	T.A. Miller
Tacoma Power	City of Tacoma, Department of Public Utilities, Light Division (Washington)
Tres Amigas	Tres Amigas LLC
TVA	Tennessee Valley Authority
US Bureau of Reclamation	United States Bureau of Reclamation
Utility Economic Engineers	Utility Economic Engineers
Vestas	Vestas-American Wind Technology, Inc.
Viridity Energy	Viridity Energy, Inc.
Vote Solar	Vote Solar Initiative
WUTC	Washington Utilities and Transportation Commission
WestConnect	Arizona Public Service Company; El Paso Electric Company, Imperial Irrigation District; NV Energy, Public Service Company of Colorado; Public Service Company of New Mexico; Sacramento Municipal Utility District; Salt River Project; Southwest Transmission Cooperative, Inc.; Transmission Agency of Northern California; Tri-State Generation and Transmission Association, Inc.; Tucson Electric Power Company and Western Area Power Administration
Western Farmers	Western Farmers Electric Cooperative
Western Grid	Western Grid Group
Xcel	Xcel Energy Services Inc.
Xtreme Power	Xtreme Power Inc.

Appendix B: *Pro Forma* Open Access Transmission Tariff

The Commission amends the following sections of the *pro forma* OATT:

a. Section 13.8

b. Section 14.6

13.8 Scheduling of Firm Point-To-Point Transmission Service:

Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently

adhered to by the Transmission Provider] before the start of the next scheduling interval provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission

Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next scheduling interval, provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

Appendix C: *Pro Forma* Large Generator Interconnection Agreement

The Commission proposes to amend and/or add the following sections of the *pro forma* LGIA:

a. Table of Contents (Add Article 8.4, Provision of Data from a Variable Energy Resource)

b. Article 1 (Add definition of Variable Energy Resource)

c. Article 8.4

Article 1 Definition

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Article 8.4 Provision of Data from a Variable Energy Resource

The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource

having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources Docket No. RM10-11-000

(Issued June 22, 2012)

LaFLEUR, Commissioner, *dissenting in part*:

I am dissenting in part on this Final Rule.

I strongly support renewable energy, and I have stated many times that I believe one of the most important jobs of this Commission is to support the development of rules to address new power supply choices being made at the state and federal level. For that reason, I support the requirements in the rule for intra-hour scheduling and power production forecasting, as well as the guidance we provide on generator regulation service charges.

I am dissenting on the narrow point of the compliance requirements in the Final Rule. As noted in the rule, we heard from many parties about ongoing efforts to establish intra-hour scheduling and other market improvements in various regions. However, the rule as issued would only allow parties to demonstrate compliance through incremental reforms beyond those already underway, without any explanation of why the ongoing efforts are insufficient. I would give regions more flexibility to demonstrate on compliance that these ongoing efforts meet the objectives of the rule.

Accordingly, I respectfully dissent in part.

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Cheryl A. LaFleur
Commissioner

June 21, 2012

News Media Contact
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Docket Nos. RM10-11-000

FERC Approves Final Rule to Integrate Variable Energy Resources

The Federal Energy Regulatory Commission (FERC) today issued a final rule that promotes more efficient operation of the transmission system amid increasing integration of variable energy resources and benefits electric consumers by ensuring that services are provided at just and reasonable rates.

Today's rule adopts two reforms from a November 2010 Notice of Proposed Rulemaking (NOPR) by requiring transmission providers to offer customers the option of scheduling transmission service at 15-minute intervals and by requiring generators using variable energy resources to provide transmission owners with certain data to support power production forecasting. Although the rule does not require the standard approach to generator regulation service proposed in the NOPR, it gives guidance on how the Commission will evaluate proposed charges for that service.

"Variable energy resources make up an increasing share of new capacity coming on-line," FERC Chairman Jon Wellinghoff said. "This final rule eliminates undue burdens on these resources and will help transmission providers and their customers effectively manage the costs of integration."

The rule finds that transmission customers are exposed to excessive imbalance service charges because they cannot adjust their service schedules within each operating hour. Intra-hour scheduling gives customers the tool they need to manage that exposure when generation output changes within the hour.

The rule allows transmission providers to submit alternative proposals that are consistent with or superior to the 15-minute scheduling reform. Any alternative proposal will need to provide equivalent or greater opportunities for transmission customers to mitigate generator imbalance penalties and for the public utility transmission provider to lower its reserve-related costs.

The final rule finds that while power production forecasts help transmission providers manage reserves more efficiently, forecasts are only as good as the data on which they rely. By requiring new interconnection customers whose generating facilities are variable energy resources to provide meteorological and operational data to transmission providers engaging in power production forecasting, FERC finds that transmission providers will better be able to manage resource variability.

In response to comments calling for flexibility in the design of reserve capacity services needed to efficiently integrate variable energy resources, the Commission decided not to require transmission providers to add to their tariffs a new schedule for generator regulation service. FERC will continue to evaluate proposed charges for that service on a case-by-case basis, and the rule provides a framework for transmission providers to develop proposed charges. The rule notes that public utility transmission providers that decide to file with the Commission to impose such a reserve capacity charge should, as part of any filing, account for the reserve costs savings associated with the reforms FERC adopts in this final rule.

The final rule takes effect **12** months after publication in the *Federal Register*.

R-12-22

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Document Content(s)

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June 21, 2012

Commissioner John R. Norris

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. : RM11-24-000, AD10-13-000 and RM10-11-000

Item Nos.: E-2 and E-3

Statement of Commissioner John R. Norris on Variable Energy Resources Final Rule and Notice of Proposed Rulemaking on Ancillary Services and Storage Technologies

"I support these two orders because I think on their own they are both important issues that the Commission needed to consider. Additionally, I support them because they represent a larger movement by the Commission and our country towards an evolving energy future. Over the last decade, policy drivers and technological advancements have resulted in a number of changes in our energy system. As a result of those changes, we can no longer go on with business as usual. We need to take a closer look at how we do things, and at existing rules that were geared towards a conventional generation fleet. Those rules have served us well in the past, but may not fit our needs going forward.

The Commission has been grappling with this new energy reality for some time now, recognizing that changes in the resources participating in our energy system will necessitate changes in how the system is operated. I see today's orders as creating operational efficiencies to mirror those policy drivers and technological advancements that are changing our energy system.

With this framework in mind, I see the reforms presented in the Final Rule on the Integration of Variable Energy Resources (VERs) and the Notice of Proposed Rulemaking on the third party provision of ancillary services as complementary (*Avista* NOPR). The VERs Final Rule addresses some of the operational changes needed to recognize the different characteristics of wind and solar technologies that are being added to our generation mix. The incremental reforms we adopt in the VERs Final Rule will help mitigate the need for ancillary services, particularly the reserves that balance and integrate VERs. Even with these reforms, however, ancillary services will still be needed to balance and integrate VERs. The *Avista* NOPR proposes to address some of the barriers to developing a more robust market for the efficient provision of these ancillary services by a variety of entities.

With respect to the VERs Final Rule specifically, the Commission initiated a rulemaking docket more than two years ago with the issuance of a Notice of Inquiry (NOI), just before I came to the Commission. That NOI, and the comments from industry and the public we received in response, covered a broad range of topics related to the integration of VERs. In the subsequent NOPR, the Commission took into account ongoing industry efforts to integrate VERs and focused its attention on a set of basic reforms regarding transmission scheduling, data reporting, and capacity reserve charges. Now, based on further feedback, we have fine-tuned this package of reforms to address some of the practical implications of the operational changes required.

I understand that we got a lot of pushback from industry, particularly about the 15 minutes scheduling requirement in the Final Rule. A lot of commenters urged us to provide them with flexibility, given their existing efforts to integrate VERs, and cautioned that compliance with the 15-minute scheduling requirement could hinder ongoing efforts that promise even greater efficiencies and benefits. We respond here by giving entities greater flexibility in meeting this requirement. However, we require entities that opt for this more flexible approach to demonstrate what efforts they will undertake to achieve greater efficiencies in their operational practices, and the Commission will evaluate on compliance whether those proposals are consistent with or superior to the requirements in the Final Rule. I do not have a pre-conceived outcome in mind as to how entities might utilize this flexibility, but I will carefully review any

proposal to ensure that it achieves needed operational efficiencies that are at least on par with those that would be provided by 15-minute scheduling.

Turning to the *Avista* NOPR, here the Commission addresses one specific aspect of the Commission's *Avista* policy – the prohibition against third-parties making market-based rate sales to a public utility that is purchasing ancillary services to satisfy its open access transmission tariff responsibilities. Since 1999 when the *Avista* restrictions were first put into place, much has changed. As a growing number of variable energy resources are coming on to the grid, there is a growing need for ancillary services such as reserves to ensure that those resources are reliably and efficiently integrated into the transmission grid. At the same time, new technologies such as storage are being developed that are capable of providing these needed ancillary services.

The *Avista* policy governing the sale of ancillary services at market-based rates to public utility transmission providers is fundamentally a consumer protection policy. However, I also believe that our rapidly changing energy landscape requires another look at the *Avista* restrictions. Today's NOPR responds to these changes on the Nation's electric grid by providing greater flexibility to sellers who want to sell ancillary services to public utility transmission providers, while balancing that flexibility with the need to continue to protect transmission customers from an exercise of market power by third-parties that could lead to unjust and unreasonable rates.

I also wanted to focus on two additional specific aspects of the NOPR proposal. First, I wanted to mention the NOPR's requirements regarding the provision of ancillary services by faster and more accurate resources. Specifically, the Commission proposes to require all public utility transmission providers (not just the RTOs and ISOs that were addressed in last year's Order No. 755) to identify how they will account for the speed and accuracy of resources used to provide Regulation and Frequency Response when establishing ancillary services requirements for customers. I am very supportive of this proposal because I believe it is essential to appropriately compensate resources that can more efficiently provide ancillary services. The flexibility of these resources can help our system be more efficient, reliable and cost-effective and that is good for consumers and should be encouraged.

Second, I wanted to highlight the accounting requirements for energy storage assets that are included in the NOPR. Rather than create a new functional classification in the Uniform System of Accounts specific to energy storage assets, the NOPR proposes to create new accounts for energy storage costs within the existing accounting functional classifications. We note that, based on our analysis, it does not appear that creating a new functional classification would provide additional benefits compared to creating new accounts within the existing classifications. I am interested in any comments about the practical impacts of this proposal on energy storage assets. I encourage storage providers to give us their input once they review our proposal.

Finally, I wanted to note that the functional classifications will not by themselves determine how energy storage assets recover their costs via cost-based and/or market-based mechanisms. Instead, the Commission will separately review any proposals from public utilities that simultaneously seek to recover costs under cost-based and market-based rate mechanisms using a single energy storage asset. The Commission will evaluate any such proposals on a case-by-case basis, separate and apart from the Commission's accounting proposal here."

June 21, 2012

Chairman Jon Wellinghoff

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. **RM11-24-000, AD10-13-000 and RM10-11-000**

Item Nos. E-2 & E-3

Statement of Chairman Jon Wellinghoff on Variable Energy Resources Final Rule and Notice of Proposed Rulemaking on Ancillary Services and Storage Technologies

"Thank you Arnie, Rahim and Jessica and both Teams for your work on these items.

You present us with two further steps in the Commissions efforts to foster competitive and efficient markets with the objective of managing wholesale electric costs for customers.

I would like to highlight some of the features that I think will be helpful to new entrants who may be able to provide lower cost services for customers.

The Avista/Electric Storage NOPR proposes to provide tools for third parties wishing to sell ancillary services in bilateral markets, in particular to public utility transmission providers for use in their OATT service, to demonstrate that they do not have market power and thus can make sales of ancillary services at market-based rates. This could provide greater opportunities for competitive sellers of ancillary services to have access to such buyers and, in turn, potentially provide these buyers with new lower cost sources of ancillary services. Thus, the overall effect is to lower costs to transmission customers.

The VERs final Rule provides, among other things, for two important tools to improve the efficiency of the power system. First, the opportunity to schedule transmission service on a 15 minute basis, and the associated cost savings, will be available for all types of resources, and is not confined to VERs. Second, the data and other requirements related to power production forecasting are designed to reflect the operational characteristics of VERS and to, accordingly, use the transmission system more efficiently. Variable energy resources make up an increasing share of new capacity coming on-line. This Final Rule eliminates undue burdens on these resources and will help transition providers and their customers to effectively manage the costs of integration.

Finally, both the Final Rule and the NOPR note the obligation of the transmission provider to provide information to customers who wish to self-supply their ancillary services about the rules and requirements to implement such a choice. This will facilitate efforts by transmission customers who choose to manage their energy costs by self-supplying some or all of the ancillary services needed to make transmission service to then reliable.

I am pleased to vote for these items."

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM12–1–000]

Transmission Planning Reliability Standards

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, petitions for the approval of modified Transmission Planning Reliability Standard, TPL–001–2 (Transmission System Planning Performance Requirements), which combines four currently effective TPL Reliability Standards, TPL–001–1, TPL–002–1b, TPL–003–1a, and TPL–004–1, into a single standard. NERC also requests retirement of the currently-effective TPL standards. Pursuant to section 215 of the Federal Power Act, the Federal Energy Regulatory Commission proposes to remand proposed Reliability Standard, TPL–001–2. The proposed Reliability Standard includes a provision that would allow a transmission planner to plan for non-consequential load loss following a single contingency provided that the plan is documented and vetted in an open and transparent stakeholder process. The Commission believes that, with the inclusion of this provision, proposed TPL–001–2 does not meet the statutory criteria for approval.

DATES: Comments are due July 6, 2012.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

• *Agency Web Site: http://ferc.gov*. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

• *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT: Eugene Blick (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–8066, *Eugene.Blick@ferc.gov*.

Robert T. Stroh (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–8473, *Robert.Stroh@ferc.gov*.

SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,059

Notice of Proposed Rulemaking

April 19, 2012

1. The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), petitions for the approval of Reliability Standard, TPL–001–2 (Transmission System Planning Performance Requirements), which combines four currently effective TPL Reliability Standards, TPL–001–1, TPL–002–1b, TPL–003–1a, and TPL–004–1, into a single standard. NERC also requests retirement of the currently effective TPL standards. Pursuant to section 215(d) of the Federal Power Act (FPA), the Federal Energy Regulatory Commission (FERC) proposes to remand proposed Reliability Standard, TPL–001–2. The proposed Reliability Standard includes a provision in Table 1 (Steady State and Stability Performance Extreme Events), footnote 12 that would allow a transmission planner to plan for ''non-consequential load loss,'' i.e., load shedding, following a single contingency provided that the plan is documented and alternatives are considered and subject to review in an open and transparent stakeholder process. As discussed below, the Commission believes that this provision is vague and unenforceable because it does not adequately define the circumstance in which an entity can plan for non-consequential load loss following a single contingency. Accordingly, the Commission proposes to find that, with the inclusion of this provision, proposed TPL–001–2 does not meet the statutory criteria for approval that a mandatory Reliability Standard must be just, reasonable, not unduly discriminatory or preferential, and in the public interest.

2. NERC states that proposed Reliability Standard TPL–001–2 introduces significant revisions and improvements to the Transmission Planning Reliability Standards, including increased specificity of data required for modeling conditions, and requires planners to address the impact of the unavailability of long lead-time critical equipment in a manner consistent with the entity's spare equipment strategy.[1] Further, according to NERC, the proposed Reliability Standard addresses twenty-seven Commission directives set forth in Order No. 693 and subsequent Commission orders.[2] We agree with NERC that proposed TPL–001–2 includes specific improvements over the currently effective Transmission Planning Reliability Standards and, as discussed below, is responsive to certain Commission directives. However, the provision in the proposed Reliability Standard allowing for transmission planners to plan for non- consequential load loss following a single contingency without adequate safeguards undermines the potential benefits the proposed Reliability Standard may provide. Section 215(d)(4) requires that the Commission remand to the ERO for further consideration a Reliability Standard ''that the Commission disapproves in whole *or in part.*'' [3] Thus, notwithstanding improvements contained in other provisions of proposed Reliability Standard TPL–001–2, our concerns regarding the stakeholder process set forth in Table 1, footnote 12 provides us no option other than to propose to remand the entire Reliability Standard.

3. We are concurrently issuing a Final Rule in Docket No. RM11–18–000 that remands a related Reliability Standard, TPL–002–0b, which contains the same objectionable stakeholder process provision in Table 1, footnote 'b'.[4] In the Final Rule in Docket No. RM11–18–000, the Commission urges NERC to employ its Expedited Reliability Standards Development Process to timely develop a modified provision regarding planned shedding of non-consequential load loss that satisfies the relevant Commission's directives in Order No. 693 and the subsequent orders. A rapid resolution of this one matter will allow the industry, NERC and the Commission to go forward with the consideration of other improvements contained in proposed Reliability Standard TPL–001–2.

I. Background

4. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently.

5. Pursuant to section 215 of the FPA, the Commission established a process to

[1] NERC Petition at 4.

[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[3] 16 U.S.C. 824o(d)(4) (2006) (emphasis added).

[4] *Transmission Planning Reliability Standards*, Order No. 762, 139 FERC ¶ 61,060 (2012).

select and certify an ERO [5] and, subsequently, certified NERC as the ERO.[6] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including the existing TPL Reliability Standards. In addition, pursuant to section 215(d)(5) of the FPA,[7] the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards, including the TPL Reliability Standards.[8]

A. Transmission Planning (TPL) Reliability Standards and Order No. 693 Directives

6. The currently-effective TPL Reliability Standards consists of four approved standards and are intended to ensure that the transmission system is planned and designed to meet an appropriate and specific set of reliability criteria. Transmission planning is a process that involves a number of stages including developing a model of the Bulk-Power System, using this model to assess the performance of the system for a range of operating conditions and contingencies, determining those operating conditions and contingencies that have an undesirable reliability impact, identifying the nature of potential options, and developing and evaluating a range of solutions and selecting the preferred solution, taking into account the time needed to place the solution in service.

7. In Order No. 693, the Commission accepted the Version 0 TPL Reliability Standards and directed NERC, pursuant to FPA section 215(d)(5), to develop modifications to TPL–001–0 through TPL–004–0 through the Reliability Standards development process. In addition, the Commission neither approved nor remanded two other planning Reliability Standards, TPL–005–0 and TPL–006–0, as these two Reliability Standards applied only to regional reliability organizations.[9] The Commission encouraged the ERO to monitor a series of technical conferences and regional meetings to obtain industry input to achieve the goal of regional planning and use the results as input to the standards development process to revise TPL–005–0 to address regional planning and related processes.[10]

8. With regard to Reliability Standard TPL–002–0b, Table 1, footnote 'b', the Commission directed NERC to clarify footnote 'b' regarding the loss of non-consequential load for a single contingency event. In a March 18, 2010 order, the Commission directed NERC to submit a modification to footnote 'b' responsive to the Commission's directive in Order No. 693, by June 30, 2010.[11] In a June 11, 2010 order, the Commission granted partial clarification to NERC and extended the compliance deadline until March 31, 2011.[12]

B. RM11–18–000 Proposed Remand of Footnote 'b'—Version 1

9. In response to the March 2010 and June 2010 Orders, on March 31, 2011, NERC submitted proposed TPL–002–1 (Version 1), which proposed to modify footnote 'b' to permit planned interruption of Firm Demand when documented and subject to an open stakeholder process. On October 20, 2011, the Commission issued a Notice of Proposed Rulemaking that proposed to remand to NERC the proposed modification to footnote 'b' because it does not adequately clarify or define the circumstances in which an entity can plan to use interruption of Firm Demand as a mitigation plan to resolve a single contingency.[13] The Commission stated that the procedural and substantive parameters of NERC's proposal are too undefined to provide assurances that the process will be effective in determining when it is appropriate to plan for interrupting Firm Demand, do not contain NERC-defined criteria on circumstances to determine when an exception for planned interruption of Firm Demand is permissible, and could result in inconsistent results in implementation. In the Final Rule issued concurrently with the NOPR in the immediate proceeding, the Commission remanded proposed Reliability Standard TPL–002–0b.

C. NERC's Petition for Approval of TPL–001–2

10. On October 19, 2011, NERC filed a petition seeking approval of Reliability Standard TPL–001–2, the associated implementation plan and Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), as well as five new definitions to be added to the NERC Glossary of Terms (Version 2). NERC also seeks approval of the retirement of the following four Reliability Standards: TPL–001–1 (System Performance Under Normal (No Contingency) Conditions (Category A)); TPL–002–1b (System Performance Following Loss of a Single Bulk Electric System (BES) Element (Category B)); TPL–003–1a (System Performance Following Loss of Two or More BES Elements (Category C)); and TPL–004–1 (System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)). In addition, NERC requests to withdraw two pending Reliability Standards: TPL–005–0 (Regional and Interregional Self-Assessment Reliability Reports) and TPL–006–0.1 (Data from the Regional Reliability Organization Needed to Assess Reliability).

11. The Version 2 standard also includes language similar to NERC's Version 1 March 31, 2011, proposal to revise and clarify footnote 'b' of Table 1 applicable in four currently-effective TPL Reliability Standards ''in regard to non-consequential firm load loss in the event of a single contingency.'' [14] The proposed Reliability Standard TPL–001–2 (Version 2) expands upon NERC's proposed footnote 'b' (Version 1) and as a result, Version 2 replaces in its entirety the Version 1 footnote 'b.' In creating TPL–001–2, the proposed footnote 'b' in Version 1 was modified slightly and carried over as Steady State & Stability Performance Footnotes 9 and 12 in Version 2. In other words, footnote 'b' in Version 1 has been divided into two footnotes in Version 2, and the subject of the concerns raised by the Commission with respect to the Version 1 footnote 'b' are now contained in footnote 12 of Version 2. Footnote 12 in Version 2 is in all material respects the same as the portion of footnote 'b' in Version 1 that is the subject of the Final Rule issued today in Docket No. RM11–18–000.

D. Proposed Reliability Standard

12. As proposed by NERC, TPL–001–2 includes eight requirements and Table 1, summarized as follows:

[5] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, order on reh'g, Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[6] *North American Electric Reliability Corp., 116 FERC ¶ 61,062, order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (DC Cir. 2009).

[7] 16 U.S.C. 824o(d)(5).

[8] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1691–1845.

[9] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1840, 1845. The currently-effective versions of the TPL Reliability Standards are as follows: TPL–001–0.1, TPL–002–0b, TPL–003–0a, and TPL–004–0.

[10] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1841.

[11] *Mandatory Reliability Standards for the Bulk Power System*, 130 FERC ¶ 61,200 (2010) (March 2010 Order).

[12] *Mandatory Reliability Standards for the Bulk Power System*, 131 FERC ¶ 61,231 (2010) (June 2010 Order).

[13] *Transmission Planning Reliability Standards*, 137 FERC ¶ 61,077 (2011).

[14] NERC Petition at 11.

Requirement R1: Requires the transmission planner and planning coordinator to maintain system models and provides a specific list of items required for the system models and that the models represent projected system conditions. The planner is required to model the items that are variable, such as load and generation dispatch, based specifically on the expected system conditions.

Requirement R2: Requires each transmission planner and planning coordinator to prepare an annual planning assessment of its portion of the bulk electric system and must use current or qualified past studies, document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and stability analyses. Requirement R2, Part 2.1.3 requires the planner to assess system performance utilizing a current annual study or qualified past study for each known outage with a duration of at least six months for certain events listed in Table 1, P1. NERC states that this requirement ensures planners evaluate every known outage with known duration of six months or more, even if the known outage is not within one of the study years selected by the planner. NERC states that the requirements and parts of proposed TPL–001–2 provide for what a valid study must entail, timeframes for use of past studies, minimum conditions, what needs to be included in the model, and what performance must be achieved. It also clarifies that qualified past studies can be utilized in the analysis while tightly defining the qualifications for those studies. The use of qualified past studies allows an entity to continue to use validated studies to complete its assessment. Requirement R2 includes a new part (2.7.3) that allows transmission planners and planning coordinators to utilize Non-Consequential Load Loss to meet performance requirements if the applicable entities are unable to complete a Corrective Action Plan due to circumstances beyond their control.

Requirements R3 and R4: Requirement R3 describes the requirements for steady state studies and Requirement R4 explains the requirements for stability studies. Requirement R3 and Requirement R4 also require that simulations duplicate what will occur in an actual power system based on the expected performance of the protection systems. These requirements are intended to ensure that if a protection system is designed to remove multiple elements from service for an event that the simulation will be run with all of those elements removed from service. Requirement R3 and Requirement R4 also include new parts that require the planners to conduct an evaluation of possible actions designed to reduce the likelihood or the consequences of extreme events that cause cascading.

Requirement R5: Requirement R5 deals with voltage criteria and voltage performance. NERC proposes in Requirement R5 that each transmission planner and planning coordinator must have criteria for acceptable system steady state voltage limits, post-contingency voltage deviations, and the transient voltage response for its system. For transient voltage response the criteria must specify a low-voltage level and a maximum length of time that transient voltages may remain below that level. This requirement will establish more robust transmission planning for organizations and greater consistency as these voltage criteria are shared.

Requirement R6: Specifies that an entity must define and document the criteria or methodology used to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding within its planning assessment.

Requirement R7: Mandates coordination of individual and joint responsibilities for the planning coordinator and the transmission planner which is intended to eliminate confusion regarding the responsibilities of the applicable entities and assures that all elements needed for regional and wide area studies are defined with a specific entity responsible for each element and that no gaps will exist in planning for the Bulk-Power System.

Requirement R8: Addresses the sharing of planning assessments with neighboring systems. The requirement ensures that information is shared with and input received from adjacent entities and other entities with a reliability related need that may be affected an entity's system planning.

Table 1: Similar to the existing TPL Standard, NERC's proposal contains a series of planning events and describes system performance requirements in Table 1 for a range of potential system contingencies required to be evaluated by the planner. Table 1 includes three parts: Steady State & Stability Performance Planning Events, Steady State & Stability Performance Extreme Events, and Steady State & Stability Performance Footnotes. Table 1 describes system performance requirements for a range of potential system contingencies required to be evaluated by the planner. The table categorizes the events as either ''planning events'' or ''extreme events.'' The proposed table lists seven Contingency planning events (P1 through P7) that require steady-state and stability analysis as well as five extreme event contingencies—three for steady-state and two for stability. The proposed table also includes a no contingency ''event'' labeled as P0 which requires steady state analysis. Footnote 12 of Table 1 provides:

> An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non- Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non- Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.[15]

II. Discussion

13. The Commission proposes to remand proposed Reliability Standard TPL–001–2. The proposed footnote 12 included as part of Reliability Standard TPL–001–2, which is in all material respects the same as the Version 1 footnote 'b' proposal described in Docket No. RM11–18–000, is unjust and unreasonable, unduly discriminatory or preferential, and not in the public interest. Although there are many improvements in the proposed TPL–001–2, the presence of footnote 12 in proposed Reliability Standard TPL–001–2 requires that the Commission remand the entire proposed Reliability Standard.[16]

14. As described in the Final Rule in Docket No. RM11–18–000, the Commission believes that NERC's footnote 'b' proposal (footnote 12 in this NOPR proceeding) does not clarify or define the circumstances in which an entity can plan to interrupt Non-Consequential Load Loss for a single contingency. The Commission is concerned that footnote 12 is inadequate and fails to address the Commission's concerns for three reasons. First, proposed footnote 12 lacks adequate parameters. Second, the NERC proposal leaves undefined the circumstances in

[15] NERC Petition at 12. In NERC's proposal in Docket No. RM11–18–000, Table 1, footnote 'b' planned load shed is called planned ''interruption of Firm Demand.'' In footnote 12, NERC has changed the term from ''interruption of Firm Demand'' to utilization of ''Non-Consequential Load Loss.''

[16] 16 U.S.C. 824o(d)(4).

which it is allowable to plan for Non-Consequential Load Loss to be utilized. The Commission believes that footnote 12 could function as a means to override the reliability objective and system performance requirements of the TPL Reliability Standard without any technical or other criteria specified to determine when planning to use Non-Consequential Load Loss to meet single contingency performance requirements would be allowable.[17] While NERC expects that such determinations will be made in a stakeholder process, this provides no assurance that such a process will use technically sound means of approving or denying exceptions.[18] Third, while the Commission recognizes that some variation among regions or entities is reasonable given varying grid topography and other considerations, there are no technical criteria to determine whether varied results are arbitrary or based on meaningful distinctions.[19] The Commission, thus, concludes that NERC's proposal lacks safeguards to ensure against inconsistent results and arbitrary determinations to allow for the planned interruption of load shed.

15. While we propose to remand Reliability Standard TPL–001–2 because of footnote 12, the Commission sees improvements to the balance of the proposed Reliability Standard. The Commission recognizes the level of complexity and substantial revision that NERC undertook to consolidate the requirements in the four currently-effective TPL Reliability Standards into one standard, and that effort has yielded improvements relative to the current set of standards. The Commission, however, seeks comments from the ERO and other interested persons regarding the following important reliability issues to ensure that the proposed Reliability Standard adequately maintains reliability and that the directives have been met: (a) Planned Maintenance Outages, (b) Violation Risk Factors, (c) Protection System Failures versus Relay Failures, (d) Assessment of Backup or Redundant Protection Systems, (e) Single Line to Ground Faults, and (f) Order No. 693 Directives.

A. Planned Maintenance Outages

16. NERC proposed new language in TPL–001–2, Requirement R1 to remove an ambiguity in the current standard concerning what the planner needs to include in the specific studies. It also requires the planner to evaluate six-month or longer duration outages within its system. NERC states that while Requirement R1.3.12 of the currently-effective TPL–002–0b, includes planned outages (including maintenance outages) in the planning studies and requires simulations at the demands levels for which the planned outages are performed, it is not appropriate to have the planner select specific planned outages for inclusion in their studies. Consequently, NERC proposes a bright-line test to determine whether an outage should be included in the system models. Specifically, NERC proposes that Requirement R1, Part 1.1.2 mandate that the system models ''shall represent * * * known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.'' [20] NERC determined that, in the planning horizon, a six-month or longer outage duration would necessarily extend over a seasonal peak load period and should be included in the planning models. Therefore, NERC states that the specific elements selected to be evaluated are selected by the transmission planner or planning coordinator and must be acceptable to the associated regional reliability organization.[21]

17. In Order No. 693 the Commission stated that in the currently-effective TPL Reliability Standards a planner must demonstrate through a valid assessment that the transmission system performance requirements can be met. The TPL Reliability Standards require that planned outages of transmission equipment must be considered for those demand levels for which planned outages are performed. By modeling the planned transmission equipment outages and through the simulation of various contingency events, a planner must demonstrate that the system can be operated to supply projected customer demands for all maintenance outage conditions and that amongst other things, cascading or system instability will not occur.[22]

18. For example, PJM has recently evaluated a Doubs-Mt. Storm project which includes the replacement of structures that have deteriorated beyond repair, which has resulted in the need to rebuild the transmission circuit. PJM indicates the maintenance outages will be scheduled in four month blocks, September—December and February—May, starting in 2011 through 2015. PJM's analysis indicates that a list of facilities has been determined that should not be scheduled out concurrently with the Doubs-Mt. Storm project. Furthermore, PJM analysis indicated that if any outage on this list of identified facilities must be taken out of service, every effort shall be made to align them with the lightest load period possible.[23] Based on NERC's proposed Requirement R1, Part 1.1.2 and the Doubs-Mt. Storm example, it appears that this type of planned maintenance outage would be excluded from future planning assessments and its potential impact to bulk electric system reliability would be unknown because the outage duration in this example is less than six months.

19. The Commission seeks comment from the ERO and interested persons whether the six month threshold would materially change the number of planned outages as compared to the current standard. The Commission also seeks comment on whether the threshold would exclude almost all planned outages from future planning assessments, such as nuclear plant refueling, large fossil and hydro generating station maintenance, spring and fall transmission construction projects and items indentified in correction actions plans of planning assessments including neighboring corrective action plans. The Commission also seeks comment on what alternative, whether based on outage duration shorter than six months or some other method, such as planners' accounting for planned maintenance outages of high capacity lines, critical transformers, or nuclear outages during non-peak load periods in their assessments, captures the appropriate number of planned outages and types of planned outages to ensure that the Bulk-Power System can be operated to meet system performance requirements during high maintenance periods like the spring and fall seasons. In addition to seasonal peaks, there have been significant system incidents which occur because of unusual weather events during non-seasonal peak periods. The Commission seeks comment on whether a six month outage window would sufficiently capture these events or if they would not be addressed in the proposed planning process. In addition, with respect to protection system maintenance, currently-effective Reliability Standard TPL–002–0, Requirement R1.3.12 requires the planner to ''[i]nclude the planned (including maintenance) outage of any bulk electric equipment (including

[17] Order No. 762, 139 FERC ¶ 61,160 at P 13.

[18] *Id.* P 14.

[19] June 2010 Order, 131 FERC ¶ 61,231 at P 21.

[20] NERC Petition at 35–36.

[21] *Id.*

[22] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1772, 1799, 1827.

[23] *See http://www.pjm.com/~/media/committees-groups/committees/pc/20110203/20110203-item-12-doubs-mt-storm-impact-summary.ashx.*

protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.'' [24] NERC did not carry over this language because protection system maintenance or other outages are not anticipated to last six months. The Commission, however, believes that it is critical to plan the system so that a protection system can be removed for maintenance and still be operated reliably. Therefore, the Commission seeks comment on its belief that protection systems are necessary to be included as a type of planned outage.

B. Violation Risk Factors

1. VRF for Proposed TPL–001–2, Requirement R1 VRF

20. NERC assigned a ''Medium'' VRF for proposed Reliability Standard TPL–001–2, Requirement R1 and its sub-requirements. NERC states each primary requirement in the proposed Reliability Standard TPL–001–2 is assigned a VRF considering the NERC guidelines and consistent with NERC's August 10, 2009 informational filing.[25] NERC maintains that Requirements R1.3.5, R1.3.7, R1.3.8, and R1.3.9 of the currently-effective Reliability Standard TPL–001–0.1 carry a VRF of ''Medium'' and are similar in purpose and effect to proposed Reliability Standard TPL–001–2, Requirement R1. NERC states that the Requirements are similar because they refer to models that include firm transfers, existing and planned facilities, and reactive power requirements, and they refer to the Table 1 P0 condition. NERC believes that a ''medium VRF for Requirement R1 is consistent with past Commission guidance.'' [26]

21. NERC stated in its filing that ''Requirement R1 of the proposed TPL–001–2 explicitly requires the Transmission Planner and Planning Coordinator to maintain System models.'' [27] The Commission believes that when the planning coordinator or the transmission planner are maintaining the system models to reflect the normal system condition, if the system models are not properly modeled or maintained, the analysis required in the Reliability Standard that uses the models in Requirement R1, such as Category P0 as the normal System condition in Table 1, may lose their validity and ''could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.'' [28]

22. Furthermore, Requirement R1 of the proposed Reliability Standard TPL–001–2 explicitly addresses the establishment of Category P0 as the normal system condition in Table 1, which creates the model of the normal system as the ''Initial Condition'' prior to any contingency.[29] Requirement R1 of the currently-effective Reliability Standard TPL–001–0, which has a VRF of ''High,'' explicitly establishes Category A as the normal system (all facilities in service) in Table 1, which also creates the model of the normal system prior to any contingency. The Commission believes that Requirement R1 of proposed Reliability Standard TPL–001–2 and Requirement 1 of currently-effective TPL–001–0 both establish the normal system planning model that serves as the foundation for all other conditions and contingencies that are required to be studied and evaluated in a planning assessment.

23. Consistent with Guideline 3 of the Commission's VRF Guidelines, the Commission ''expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals to be treated comparably.'' [30] The Commission seeks comment on why Requirement R1 of proposed Reliability Standard TPL–001–2 carries a VRF of ''Medium'' while Requirement R1 of the currently-effective Reliability Standard TPL–001–0 carries a VRF of ''High.''

2. VRF for Proposed TPL–001–2, Requirement R6

24. NERC proposes to assign a ''Low'' VRF for Requirement R6 from the proposed Reliability Standard TPL–001–2 because ''failure to have established criteria for determining System instability is an administrative requirement affecting a planning time frame.'' [31] NERC explains that Requirement R6 is a new requirement and that violations would not be expected to adversely affect the electrical state or capability of the bulk electric system.

25. Requirement R6 requires planning coordinators and transmission planners to define and document the criteria or methodology used in their analyses to identify system instability for conditions such as cascading, voltage instability or uncontrolled islanding. The Commission recognizes that documenting criteria or methodology is an administrative act. However, defining the criteria or methodology to be used is not an administrative act. If the criteria or methodology used by planning coordinators and transmission planners are not defined properly, the analysis based on this criteria or methodology could lose its validity and ''could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.'' [32]

26. Requirement R6 co-mingles a higher reliability objective (defining criteria or methodology) with a lower reliability objective (documentation). Consistent with Guideline 5 of the Commission's VRF Guidelines, the Commission seeks to ensure that the assignment of Violation Risk Factors corresponding to co-mingled Requirements reflect the higher reliability objective of the co-mingled requirement.[33] The Commission seeks clarification from the ERO why the VRF level assigned to Requirement R6 is ''Low'' since it is appears that Requirement R6 requires more than a purely administrative task.

C. Protection System Failures Versus Relay Failures

27. NERC states that its modification to the planning contingency categories in Table 1 of the proposed standard is intended to add clarity and consistency regarding how a delayed fault clearing will be modeled in planning studies. NERC states that the basic elements of any protection system design involve inputs (i.e., current and D/C and A/C voltage) to protective relays and outputs (i.e., trip signals, close signals, and

[24] Reliability Standard TPL–002–0, Requirement R1.3.12.

[25] Informational Filing of the North American Electric Reliability Corporation Regarding the Assignment of Violation Risk Factors and Violation Severity Levels, Docket Nos. RM08–11–000, RR08–4–000, RR07–9–000, and RR07–10–000 (August 10, 2009).

[26] NERC Petition at Exhibit C, Table 1.

[27] NERC Petition at 34.

[28] *North American Electric Reliability Corp., order on violation risk factors,* 119 FERC ¶ 61,145, at P 9 (2007), *order on reh'g and compliance filing,* 120 FERC ¶ 61,145 (2007).

[29] Proposed Reliability Standard TPL–001–2, Table 1.

[30] *North American Electric Reliability Corp., order on violation risk factors,* 119 FERC ¶ 61,145, at P 25 (2007), *order on reh'g and compliance filing,* 120 FERC ¶ 61,145 (2007).

[31] NERC Petition, Exhibit C, at 110.

[32] *North American Electric Reliability Corp., order on violation risk factors,* 119 FERC ¶ 61,145 at P 9.

[33] *Id.* P 32.

alarms) from protective relays and that reliability issues associated with improper clearing of a fault on the bulk electric system can result from the failure of hundreds of individual protection system components in a substation. However, NERC believes that while the population of components that could fail and result in improper clearing is large, that population can be reduced dramatically by eliminating those components which share failure modes with other components. NERC states that the critical components in protection systems are the protective relays themselves, and a failure of a non-redundant protective relay will often result in undesired consequences during a fault. According to NERC, other protection system components related to the protective relay could fail and lead to a bulk electric system issue, but the event that would be studied is identical, from both transient and steady state perspectives, to the event resulting from a protective relay failure if an adequate population of protective relays is considered.[34]

28. In the currently-effective TPL Reliability Standards, Table 1 contingencies address the initiating event and contingency of a single line to ground (SLG) fault with delayed clearing (stuck breaker or protection system failure) for a generator, transformer, transmission circuit and bus section. For this initiating event and set of contingencies, the planner must demonstrate that Table 1 system performance criteria can be met.[35]

29. Currently-effective Reliability Standard TPL–003–0, Requirement R1.3.1 states that current or past study and/or system simulation testing ''[b]e performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts.'' [36] Referring to Table 1, Category C6–C9, the initiating event and contingency is described as ''SLG Fault, with Delayed Clearing (stuck breaker or protection system failure).'' [37]

30. Requirement R1.3.1 states that in the study and simulation of a protection system failure, the planner should assess the contingencies that produce the more severe system results.[38] If the contingency is a protection system failure, delayed clearing is described as a fault due to the failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.[39]

31. The Commission believes that based on various protection system as-built designs, the planner will have to choose which protection system component failure would have the most significant impact on the Bulk-Power System because as-built designs are not standardized and the most critical component failure may not always be the relay. For example, if a protection system design used one set of fuses to supply power to both the primary and breaker failure relays, failure of one fuse would be more severe than failure of either one of the relays. Similar dependencies can occur in specific designs in the implementation of microprocessor installations. As another example, if a protection system designed includes a shared voltage or current sensing device that provides input to relays for both the primary and backup protection systems, failure of this voltage sensing device would be more severe than failure of either one of the relays.

32. As a result, the planner's selection of a protection system component failure may be influenced by the protection system as-built design. If one protection system component was an integral component of primary protection and breaker failure protection, then it is possible that the loss of that one component would produce the more severe system impact. If, in this example, the protection system component failure was not a relay component, as described in Category P5 of the proposed TPL Standard, it appears that this more severe contingency (loss of both the primary protection and breaker failure protection systems due to the loss of one protection system component) would not be assessed under the proposed TPL Reliability Standard.

33. The Commission seeks comments on whether the proposed TPL Reliability Standard, in the provisions pertaining to study of multiple contingencies, limits the planners' assessment of a protection system failure because it only includes the contingency of a faulty relay component. The Commission also seeks comments on whether, based on protection system as-built designs, the relay may not always be the larger contingency, and how the loss of protection system components that may be integral to multiple protection systems impacts reliability.

D. Assessment of Backup or Redundant Protection Systems

34. NERC states that proposed Reliability Standard TPL–001–2, Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require that simulations faithfully duplicate what will happen in an actual power system based on the expected performance of the protection systems.[40] According to NERC, these requirements ensure that if a protection system is designed ''to remove multiple Elements from service for an event that the simulation will be run with all of those Elements removed from service.'' [41] This proposal is intended to instill event-based analysis over simple element analysis which will provide for more accurate simulations.

35. The current TPL Reliability Standards state that a planner must include the effects of existing and planned protection systems, including any backup or redundant systems in its planning assessment.[42] Specifically, Reliability Standard TPL–003–0, Requirement R1.3.10 requires the planner to ''[i]nclude the effects of existing and planned protection systems, including any backup or redundant systems.'' [43] For this requirement, the planner must include the effects all protection systems, including backup or redundant protection systems.

36. NERC states that Reliability Standard TPL–001–2, Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require the planner to ''[s]imulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.'' The proposed NERC provision, however, does not explicitly refer to ''backup or redundant systems'' as in the currently effective TPL standards. The Commission seeks clarification from the ERO whether the proposed Requirements address all protection systems, including backup and redundant protection systems that can have an impact on the performance of the bulk electric system.

E. P5 Single Line to Ground Faults

37. Table 1 of the proposed Reliability Standard TPL–001–2 identifies the

[34] NERC Petition at 48.

[35] Currently-effective Reliability Standard TPL–004–0, Categories C1–C4 address the same initiating event and set of contingencies as currently-effective TPL–003–0, Categories C6–C9, but the system performance criteria are different for TPL–003–0 versus TPL–004–0.

[36] Reliability Standard TPL–003–0a.

[37] Reliability Standard TPL–003–0a (Category C).

[38] Requirement R1.3.1 is included in TPL–002–0b, TPL–003–0a and TPL–004–0.

[39] Reliability Standard TPL–003–0, Table 1, footnote e.

[40] NERC Petition at 20.

[41] *Id.*

[42] *E.g.,* Reliability Standards TPL–003–0, R1.3.10 and TPL–004–0, R1.3.7.

[43] Reliability Standard TPL–003–0, R1.3.10 and TPL–004–0, Requirement R1.3.7.

initiating contingencies that must be evaluated to ensure that the planned system meets the performance requirements. These proposed modifications to Table 1 include changing the classification of the events, clarifying events and fault types, and removing the ambiguity of performance requirements. NERC states the proposed Reliability Standard TPL–001–2, Table 1, P5 events are limited to the Single Line to Ground (SLG) Fault type consistent with the comparable C6–C9 events from Table 1 in the currently-effective TPL Reliability Standards. NERC treats SLG and three phase faults as different events even if an SLG event evolves into a three phase fault.[44]

38. The proposed Reliability Standard TPL–001–2, Table 1 includes a column titled ''fault type,'' which contains the specific designation of the fault type such as SLG or three-phase faults. ''Fault type'' is described as a SLG or three-phase fault types that must be evaluated in stability simulations for the event described. For example, a SLG fault could evolve into a 3-phase fault, but the initiating fault is the SLG fault and the associated SLG performance criteria must be applied, not the three-phase performance criteria. The Commission seeks clarification from the ERO whether ''fault types'' in Table 1 of the proposed Reliability Standard refers to the initiating event or initiating fault for the contingency rather than the type of fault in to which the initiating fault may evolve and how the clarification is consistent with the simulations being representative of what will occur in real-time.

F. Order No. 693 Directives

39. While the Commission proposes to remand based on the presence of footnote 12, the balance of proposed Reliability Standard TPL–001–2 appears responsive to the Order No. 693 directives regarding the TPL Reliability Standards. The Commission, however, seeks clarification and comment on the following.

1. Peer Review of Planning Assessments

40. In Order No. 693, the Commission stated that it ''sees no reason why peer reviews should not be part of a Reliability Standard since TPL–001–0 through TPL–004–0 already include···a review of assessment by the associated regional reliability organization.'' [45]

The Commission also stated that because neighboring systems may be adversely impacted by other neighboring systems, such systems should be involved in determining and reviewing system conditions and contingencies to be assessed under the currently-effective TPL Standards.[46] Furthermore, the peer review provides for a neighboring entity to identify possible interdependent or adverse impacts on its neighboring systems and thus, provides for an early opportunity to provide input and coordinate plans.[47]

41. NERC states the proposed Reliability Standard does not include a ''peer review'' of planning assessments but instead includes ''an equally effective and efficient manner to provide for the appropriate sharing of information with neighboring systems'' with the incorporation of Requirement R3, Part 3.4.1, Requirement R4, Part 4.4.1, and Requirement R8.[48] Part 3.4.1 provides:

> The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.[49]

NERC explains that ''an entity may always decline an offer to participate in a peer review even when they should participate'' and ''the distribution approach means that the entity will always receive the Planning Assessment.'' [50] NERC further states in ''the course of the continuing cycle of Planning Assessments, comments from other entities at the end of a planning cycle will be utilized at the beginning of the next cycle as the planner moves forward in time.'' [51]

42. The Commission seeks clarification on how the NERC proposal ensures the early input of peers into the planning assessments or any type of coordination amongst peers will occur. The Commission seeks comment on whether and how there is a sufficient level of evaluation and ability to provide feedback to the planners on the development and result of assessments. In addition, NERC states that that Requirement R8 ''ensures that information is shared with * * * adjacent entities'' which ''ensures * * * input received from adjacent entities.'' [52] The Commission also seeks comment on whether Requirement R8 requires input on the comments to be included in the results or the development of the Planning Assessments.

2. Spare Equipment Strategy

43. In Order No. 693, the Commission directed NERC to develop a modification ''to require assessments of outages of critical long lead-time equipment, consistent with the entity's spare equipment strategy.'' [53] In response, NERC developed proposed Requirement 2, Part 2.1.5 which addresses steady state conditions to determine system response when equipment is unavailable for prolonged periods of time. The studies must be performed for the P0, P1, and P2 categories in Table 1 ''under the condition that the system is expected to experience during the possible periods of unavailability of the long lead-time equipment.'' NERC states that ''[s]tability impacts related to outages of critical long lead-time equipment will not be addressed in a separated requirement but rather will be analyzed in the normal planning process.'' [54]

44. NERC's spare equipment strategy appears to have limited the strategy to steady state analysis (excluded stability analysis).[55] While including a spare equipment strategy in the proposed Reliability Standard is an improvement, the Commission seeks clarification as to why stability analysis conditions were excluded from the spare equipment strategy.

3. Controlled Load Interruption

45. In Order No. 693, the Commission directed the ERO to modify footnote (c) of Table 1 to the Reliability Standard TPL–003–0a to clarify the term ''controlled load interruption'' to ''ensure that third parties have access to the same options that the transmission owner uses to alleviate reliability constraints including those related to controlled load shedding.'' [56] NERC states in its petition that it excluded the term ''controlled load interruption'' in the proposed Reliability Standard TPL–001–2, but NERC does not explain the

[44] NERC Petition at 49. Three phase events in the existing TPL standards are shown in Table 1, D1–D4 and are retained in TPL–001–2, Table 1, Extreme Events.

[45] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1755.

[46] *Id.* P 1750.

[47] *Id.* P 1754.

[48] NERC Petition at 21.

[49] Proposed Reliability Standard, TPL–001–2, Requirement R3, Part 3.3.1. Part 4.4.1 is in all material respects the same as Part 3.3.1.

[50] NERC Petition at 22. Requirement R8 requires distribution to adjacent planning coordinators and transmission planners within 90 days and to others with a reliability related need that submits a request within 30 days of receiving such a request.

[51] NERC Petition at 22.

[52] Id. at 44.

[53] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1786.

[54] NERC Petition at 25.

[55] Proposed Reliability Standard TPL–001–2, Requirement R 2.1.5.

[56] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1818.

reason for its exclusion.[57] NERC added the term ''Non-Consequential Load Loss'' to the proposed Reliability Standard TPL–001–2, Table 1 and defined ''Non-Consequential Load Loss'' as: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.[58] In addition, NERC added a new Requirement R2.1.4 for the Near-Term Transmission Planning Horizon portion of steady-state analysis that includes ''Controllable Loads'' as one of the conditions the planning assessment must vary in the sensitivity analysis for system peak load for year one or year two, and for year five and for system off-peak load for one of the five years.

46. The term ''controlled load interruption'' is found in footnote (c) which is applicable to ''Loss of Demand or Curtailed Firm Transfers'' in Table 1 of the existing TPL Reliability Standards. The term ''Loss of Demand or Curtailed Firm Transfers'' for controlled load interruptions in Table 1 of the current TPL Standards appears to be applicable to ''Non-Consequential Load Loss Allowed'' in Table 1 of the proposed TPL Standard. The Commission seeks clarification from the ERO if third-parties have access to the same options that the transmission owner has to alleviate reliability constraints including load shedding options for ''Controllable Loads'' in Requirement 2.1.4 and ''Non-Consequential Load Loss Allowed'' in Table 1 of the proposed Reliability Standard TPL–001–2.

4. Range of Extreme Events

47. In Order No. 693 the Commission directed the ERO to modify Reliability Standard TPL–004–0 to require that, in determining the range of the extreme events to be assessed, the contingency list of Category D would be expanded to include recent events such as hurricanes and ice storms. NERC's proposed Reliability Standard TPL–001–2 appropriately expands the list of extreme event examples in Table 1, but the list limits these items to the loss of two generating stations under Item No. 3a.[59]

48. The Commission seeks clarification from the ERO on conditioning extreme events on the loss of two generating stations.[60] The Commision understands that there are scenarios where an extreme event can impact more than two generation stations that might not be captured due to the ''two generation stations'' restriction in Item No. 3a. For example, within the Florida peninsula, depending on the location within the state, either two or three main gas pipelines supply the majority of the generation for the area. In this scenario, the loss of one of the gas pipelines would result in the loss of more than two generation stations. The Commission seeks clarification regarding whether this scenario is otherwise covered under the catch-all provision in Item No. 3b which states ''[o]ther events based upon operating experience that may result in wide area disturbances.''

5. Assessments and Documentation

49. The Commission seeks clarification from the ERO that planning assessments and associated documentation will include accurate representations of results on the bulk electric system with respect to the following.

a. Dynamic Load Models

50. In Order No. 693, the Commission directed ''the ERO to modify the Reliability Standard to require documentation of load models used in system studies and the supporting rationale for their use.'' [61] Proposed Reliability Standard TPL–001–2, Requirement 2.4, Part 2.4.1 requires a load model which represents the expected dynamic behavior of loads that could impact a study area, considering the behavior of induction motor loads. NERC states that this addition to the proposed standard addresses the specifics of the Order No. 693 directive that requires ''[d]ocument(ing) the load models used in system studies and the supporting rationale for their use.'' [62] Under the proposed Requirement R2, entities are required to document assumptions made in the planning assessments. The Commission seeks clarification on whether the documentation of the dynamic load models used in system studies and the supporting rationale for their use under Requirement 2.4, Part 2.4.1 will be included in the documented assumptions under Requirement R2.

b. Proxies To Simulate Cascade

51. In Order No. 693, the Commission observed that ''if an entity models overload relays, undervoltage relays, all remedial action schemes including those of neighboring systems and has a good load representation, then proxies are not required. However, due to modeling and simulation limitations this is often not the case and planners invariably use proxies.'' [63] Additionally, the Commission stated that sharing of proxies will improve knowledge and understanding and promote a more rigorous approach to analyzing cascading outages. Accordingly, the Commission directed the ERO to modify the Reliability Standard to require ''definition and documentation of proxies necessary to simulate cascading outages.'' [64]

52. NERC states that proposed Requirement R6 ''specifies that an entity must define and document the criteria or methodology used to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding within its Planning Assessment.'' [65] NERC adds that this specificity in identifying these ''proxies'' is an important clarification in the proposed revised standard and ''will lead to greater transparency in the planner's evaluation techniques.'' [66] The Commission seeks clarification on whether Requirement R6 includes the documentation of proxies and that Requirement R8 includes the sharing of the documented proxies in the planning assessments.

c. Footnote 'a'

53. In Order No. 693 the Commission directed NERC to modify ''footnote (a) of Table 1 with regard to applicability of emergency rating and consistency of normal ratings and voltages with values obtained from other reliability standards.'' [67] NERC notes that proposed Table 1, header note 'e,' which states planned system adjustments must be executable within the time duration applicable to facility ratings, and header note 'f,' which states applicable facility ratings shall not be exceeded, meets this directive thereby replacing footnote 'a' in the current standard.

54. The Commission observes that the proposed standard applies header note 'e' to ''Steady State and Stability'' while header note 'f' is excluded from ''Stability'' and only applies to ''Steady

[57] NERC Petition at 28.

[58] In Order No. 693, the Commission explained that the term ''consequential load loss'' referred to ''the load that is directly served by the elements that are removed from service as a result of the contingency.'' Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794 n.461.

[59] NERC Petition at 29–30.

[60] *Id.*

[61] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1789.

[62] NERC Petition at 26.

[63] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1819.

[64] *Id.* P 1820.

[65] NERC Petition at 43–44.

[66] *Id.*

[67] *Id.* at 24.

State'' studies. The Commission seeks clarification from the ERO regarding the rationale for excluding header note 'f' from ''Stability'' studies. Additionally, the Commission seeks clarification on which Reliability Standards the entities should utilize when obtaining the values to be used in their Planning Assessments. In addition, for Table 1, header notes 'e' and 'f,' the Commission seeks comment on whether the normal facility ratings align with, for example, FAC–008–1 and normal voltage ratings align with VAR–001–1. Furthermore, the Commission seeks clarification from the ERO whether facility ratings used in planning assessments align with other reliability standards such as NUC–001–2, BAL–001–0.1a and PRC Standards for UFLS and UVLS.

G. Commission Proposal

55. The Commission proposes to remand NERC's proposed TPL Reliability Standard. While much of the proposed Reliability Standard TPL–001–2 appears just, reasonable, not unduly discriminatory or preferential, and in the public interest, we find that footnote 12, allowing for transmission planners to plan for non-consequential load loss following a single contingency without adequate safeguards, undermines the potential benefits the proposed Reliability Standard may provide . This is consistent with the Commission's Final Rule in Docket No. RM11–18–000 remanding footnote 'b,' which is substantially the same as footnote 12. Thus, the Commission proposes to remand the proposed Reliability Standard TPL–001–2 to NERC.

III. Information Collection Statement

56. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[68] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[69]

57. As stated above, the subject of this NOPR is NERC's proposed modifications to the TPL Reliability Standards. This NOPR proposes to remand the proposed revisions to NERC. By remanding the proposal, the applicable Reliability Standards and any information collection requirements are unchanged. Therefore, the Commission will submit this NOPR to OMB for informational purposes only.

58. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *data.clearance@ferc.gov*, phone: (202) 502–8663, or fax: (202) 273–0873].

IV. Regulatory Flexibility Act

59. The Regulatory Flexibility Act of 1980 (RFA) [70] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[71] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[72] The RFA is not implicated by this NOPR because the Commission is remanding the proposed TPL Reliability Standard and not proposing any modifications to the existing burden or reporting requirements. With no changes to the Reliability Standards as approved, the Commission certifies that this NOPR will not have a significant economic impact on a substantial number of small entities.

V. Comment Procedures

60. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due 60 days from publication in the **Federal Register**. Comments must refer to Docket No. RM12–1–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

61. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov*. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

62. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

63. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VI. Document Availability

64. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington DC 20426.

65. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

66. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov*.

By direction of the Commission. Commissioner Norris is concurring in part with a separate statement attached.

Kimberly D. Bose,

Secretary.

Norris, Commissioner, *concurring in part:*

In today's order, the Commission proposes to remand proposed Transmission Planning Reliability Standard TPL–001–2 to NERC, based on the decision by the Commission to remand proposed TPL–002–0b in the concurrently-issued *Transmission Planning*

[68] 5 CFR 1320.11.

[69] 44 U.S.C. 3507(d).

[70] 5 U.S.C. 601–612.

[71] 13 CFR 121.201.

[72] *Id.*

Reliability Standards.[1] For the reasons articulated in my separate statement in Order No. 762, I agree with the decision here to remand proposed TPL–001–2, but I do not fully agree with the basis identified by the majority in their decision.

Thus, I respectfully concur in part.

John R. Norris,
Commissioner

[FR Doc. 2012–10943 Filed 5–4–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF TRANSPORTATION

Federal Transit Administration

49 CFR Part 661

[Docket No. FTA–2012–0009]

Notice of Proposed Buy America Waivers

AGENCY: Federal Transit Administration (FTA), DOT.

ACTION: Notice of proposed Buy America waivers and request for comments.

SUMMARY: The Federal Transit Administration (FTA) received several requests to waive its Buy America requirements for products used in ticket vending machines—the Mars Electronics International (MEI) Sodeco BNA57/542 Bill Handling Unit, and BNR3–XX, BNR4–XX and BNR5–XX Bank Note Recycler product; and the Nextek Corporation (Nextek) BV–6000AG (BV–6000) Currency Validator Tekpak. FTA seeks public comment before deciding whether to grant the requests.

DATES: Comments must be received by June 6, 2012. Late filed comments will be considered to the extent practicable.

ADDRESSES: Please submit your comments by only one of the following means, identifying your submissions by docket number FTA–2012–0009. All electronic submissions must be made to the U.S. Government electronic site at *www.regulations.gov*. Commenters should follow the instructions below for mailed and hand delivered comments.

(1) *Web site: www.regulations.gov.* Follow the instructions for submitting comments on the U.S. Government electronic docket site;

(2) *Fax:* (202) 493–2251;

(3) *Mail:* U.S. Department of Transportation, 1200 New Jersey Avenue SE., Docket Operations, M–30, Room W12–140, Washington DC, 20590–0001.

(4) *Hand Delivery:* Room W12–140 on the first floor of the West Building, 1200 New Jersey Avenue SE, Washington, DC 20590, between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays.

Instructions: All submissions must refer to the ''Federal Transit Administration'' and include docket number FTA–2012–0009. Due to security procedures in effect since October 2001, mail received through the U.S. Postal Service may be subject to delays. Parties making submissions responsive to this notice should consider using an express mail firm to ensure the prompt filing of any submissions not filed electronically or by hand. Note that all submissions received, including any personal information therein, will be posted without change or alteration to *www.regulations.gov*. For More information, you may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477), or visit *www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: Jayme L. Blakesley at (202) 366–0304 or *jayme.blakesley@dot.gov*.

SUPPLMENTARY INFORMATION: The purpose of this notice is to seek public comment on whether the Federal Transit Administration should continue to waive its Buy America requirements for two years for Mars Electronics International (MEI)'s Sodeco BNA57/542 Bill Handling Unit BNR3–XX, BNR4–XX and BNR5–XX Bank Note Recycler products, and the Nextek Corporation's (Nextek) BV–6000AG (BV–6000) Currency Validator Tekpak, or whether FTA should extend the non-shift approach adopted in its 2007 Final Rule (72 FR 53688, September 20, 2007) to the procurement of such devices.

Waiver Request: MEI Sodeco BNA57/542 Bill Handling Unit

MEI requested an extension of the Buy-America non-availability component waiver under CFR 661.7(g) for the MEI Sodeco BNA57/542 Bill Handling Units. The FTA granted the initial waiver for these products on July 21, 2000, and has extended the waiver periodically ever since, on December 10, 2003, November 12, 2004, October 20, 2006, and February 23, 2009.

Buy America requires, with few exceptions, that all steel, iron and manufactured goods used in FTA-funded projects be produced in the United States. One such exception is that of non-availability, that in some instances steel, iron, and goods produced in the United States are not produced in the United States in sufficient and reasonably available quantities or are not of a satisfactory quality. Therefore, Congress authorized FTA to waive the above requirement and allow, based on non-availability, the use in an FTA-funded project of steel, iron or manufactured goods produced outside the United States.

According to MEI, the Sodeco BNA57/542 Bill Handling Units includes a multiple bill escrow (up to 15 bills) that enables return of the customer's inserted bills in situations where the transaction is not complete. The unit has the ability to identify, validate and accept multiple note denominations (US $1, $5, $10, $20, $50, $100) utilizing all optical recognition, and allowing for the acceptance of bills in a face up or face down orientation. It also supports remote download, giving a transit agency the option of downloading new bill recognition software (bill variants) via network from one central location.

MEI's customers include the Washington Metropolitan Area Transit Authority (WMATA), New York City Transit (MTA), and the Bay Area Rapid Transit Authority (BART).

In 1999, to support its initial waiver request, MEI performed a market research study. It found no equivalent products manufactured within the United States. In preparation of the instant waiver request, MEI reviewed its earlier findings and compared them with the known providers of payment systems to the transit market. They found no US manufacturers of functionally equivalent products. Companies they identified who supply a similar product—GAO/Geiseke & Deviran (G&D), Toyocom, and Cashcode—all manufacture their products outside of the United States.

Waiver Request: MEI BNY3–XX & BNR5–XX Bank Note Recycler Products

In a letter dated February 28, 2011, MEI requested an extension of the Buy America non-availability component waiver under CFR 667.7(g) for BNY3–XX & BNR5–XX Bank Note Recycler products. The initial waiver was granted by FTA on October 20, 2008. The Bank Note Recycler (BNR) can accept and validate bank notes and pay them back out as change. The unit has the ability to identify, validate and accept multiple bank note denominations (US $1, $5, $10, $20, $50, $100) utilizing all optical recognition. This allows for the acceptance of bank notes in a face-up or facedown orientation. The unit has multiple-note escrow function (up to 15 Bank notes) that enables return of the customer's inserted bank notes, in situations where the transaction is not complete, or presentation of bank notes

[1] Order No. 762, 139 FERC ¶ 61,060 (2012).

139 FERC ¶ 61,247
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

Docket Nos. RM12-6-000 and RM12-7-000

Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure

(Issued June 22, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to approve a modification to the currently-effective definition of "bulk electric system" developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The revised definition of "bulk electric system" removes language allowing for regional discretion in the currently-effective bulk electric system definition. The revised definition establishes a bright-line threshold that includes all facilities operated at or above 100 kV. The modified definition also identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of "bulk electric system."

The Commission also proposes to approve: (1) NERC's contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, or remove elements from, the definition of "bulk electric system" on a case-by-case

basis; (2) NERC's proposed form entitled "Detailed Information to Support an Exception Request" that entities will use to support requests for exception from the "bulk electric system" definition; and (3) NERC's proposed implementation plan for the revised "bulk electric system" definition.

DATES: Comments are due [INSERT DATE 60 days after publication in the **FEDERAL REGISTER**]

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

Susan Morris (Technical Information)
Office of Electric Reliability, Division of Reliability Standards
Federal Energy Regulatory Commission
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SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,247
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure	Docket Nos.	RM12-6-000 RM12-7-000

NOTICE OF PROPOSED RULEMAKING

(Issued June 22, 2012)

1. Under section 215 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) proposes to approve a modification to the currently-effective definition of "bulk electric system" contained in NERC's *Glossary of Terms Used in Reliability Standards* (NERC Glossary) developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. NERC submitted its petition in response to the Commission's directive in Order No. 743 that NERC develop a revised definition of "bulk electric system" using NERC's Reliability Standards development process.[2] The revised definition of bulk electric system:

[1] 16 U.S.C. § 824o (2006).

[2] *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 133 FERC ¶ 61,150, *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011).

(a) removes the basis for regional discretion in the current bulk electric system definition;

(b) establishes a bright-line threshold so that the "bulk electric system" will be facilities operated at 100 kV or higher, if they are Transmission Elements, or connected at 100 kV or higher, if they are Real Power or Reactive Power resources; and

(c) contains specific inclusions (I1-I5) and exclusions (E1-E4) to provide clarity in the definition that the facilities described in these configurations are included in or excluded from the "bulk electric system."

2. The Commission also proposes to approve:

(a) NERC's contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, and remove elements from the definition of "bulk electric system" on a case-by-case basis;

(b) NERC's proposed form entitled "Detailed Information to Support an Exception Request" that entities will use to support requests for exceptions from the "bulk electric system" definition; and

(c) NERC's proposed implementation plan for the revised "bulk electric system" definition.

3. NERC's proposed revision to the definition of "bulk electric system" removes regional discretion and establishes a 100 kV bright-line threshold. Further, we believe that NERC's proposal offers additional clarity to the definition of bulk electric system by creating specific inclusions and exclusions within the definition, which provide

granularity with regard to common types of facilities and facility configurations and whether they are part of the bulk electric system.

4. We believe that the proposed "core" definition, including the inclusions and the exclusions, as well as the exception process should produce consistency in identifying bulk electric system elements across the reliability regions. In addition, it appears that NERC's proposed exception process to add elements to, and remove elements from, the definition of the bulk electric system adds transparency and uniformity to the process.

5. Although it is rare that the Commission would address Rules of Procedure changes in a rulemaking docket, we will do so in this instance because of the interplay between NERC's modified bulk electric system definition and the newly developed case-specific exception process set forth in NERC's proposed Rules of Procedure change. While we propose to approve NERC's petitions, we also seek comment from NERC and interested parties on certain aspects of NERC's petitions to understand the application of the proposed "core" definition, including the application of the inclusions and exclusions, and the proposed exception process to ensure consistent implementation.

I. Background

A. Section 215 of the FPA

6. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject

to Commission oversight, or by the Commission independently.[3] The Commission established a process to select and certify an ERO[4] and, subsequently, certified NERC as the ERO.[5]

B. Order No. 693

7. On March 16, 2007, in Order No. 693, pursuant to section 215(d) of the FPA, the Commission approved 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the NERC Glossary, which includes NERC's definition of bulk electric system.[6] That definition provides:

> As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.[7]

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[3] *See* 16 U.S.C. § 824o(e)(3) (2006).

[4] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[5] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006) (certifying NERC as the ERO responsible for the development and enforcement of mandatory Reliability Standards), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[6] *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[7] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 75 n.47 (quoting NERC's definition of "bulk electric system").

8. In approving NERC's definition of bulk electric system, the Commission stated that "at least for an initial period, the Commission will rely on the NERC definition of bulk electric system and NERC's registration process to provide as much certainty as possible regarding the applicability to and the responsibility of specific entities to comply with the Reliability Standards."[8] The Commission also stated that "[it] remains concerned about the need to address the potential for gaps in coverage of facilities."[9]

C. Order Nos. 743 and 743-A

9. On November 18, 2010, the Commission revisited the definition of "bulk electric system" in Order No. 743, which directed NERC, through NERC's Reliability Standards Development Process, to revise its definition of the term "bulk electric system" to ensure that the definition encompasses all facilities necessary for operating an interconnected transmission network. The Commission also directed NERC to address the Commission's technical and policy concerns. Among the concerns were inconsistency in application of the definition and a lack of oversight and exclusion of facilities from the bulk electric system that are required for the operation of the interconnected transmission network. In Order No. 743, the Commission stated that the best way to address these concerns is to eliminate the Regional Entity discretion to define bulk electric system

[8] *Id.* P 75; *see also* Order No. 693-A, 120 FERC ¶ 61,053 at P 19 ("the Commission will continue to rely on NERC's definition of bulk electric system, with the appropriate regional differences, and the registration process until the Commission determines in future proceedings the extent of the Bulk-Power System").

[9] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 77 (footnotes omitted).

without NERC or Commission review, maintain a bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and adopt an exemption process and criteria for removing from the bulk electric system facilities that are not necessary for operating the interconnected transmission network.[10] However, Order No. 743 did not require NERC to adopt these recommendations as the sole means to address the Commission's concerns. Instead, the Commission allowed NERC to "propose a different solution that is as effective as, or superior to, the Commission's proposed approach in addressing the Commission's technical and other concerns so as to ensure that all necessary facilities are included within the scope of the definition."[11] The Commission directed NERC to file the revised definition of bulk electric system and its process to exempt facilities from inclusion in the bulk electric system within one year following the effective date of the final rule.[12]

10. In Order No. 743-A the Commission reaffirmed its determinations in Order No. 743. In addition, the Commission clarified that the issue the Commission directed NERC to rectify was the discretion the Regional Entities have under the current definition to define the bulk electric system in their regions without any oversight from

[10] Order No. 743, 133 FERC ¶ 61,150 at P 16.

[11] *Id.*

[12] *Id.* P 113.

the Commission or NERC.[13] The Commission also clarified that it was not the Commission's intent through its determination regarding "impact-based methodologies" to disrupt the NERC Rules of Procedure or the Statement of Compliance Registry Criteria (Registry Criteria).[14] Nor did the Commission intend to rule out using any form of a material impact test that can be shown to identify facilities needed for reliable operation.[15] The Commission also clarified that the 100 kV threshold was a "first step or proxy" for determining which facilities should be included in the bulk electric system.[16]

11. The Commission further clarified that the statement in Order No. 743, "determining where the line between 'transmission' and 'local distribution' lies … should be part of the exemption process the ERO develops" was intended to grant discretion to NERC, as the entity with technical expertise, to develop criteria to determine how to differentiate between local distribution and transmission facilities in an objective, consistent, and transparent manner.[17] The Commission stated that the "seven factor test" adopted in Order No. 888 could be relevant and possibly is a logical starting point for determining which facilities are local distribution for reliability purposes.[18] However, the

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[13] Order No. 743-A, 134 FERC ¶ 61,210 at P 11.

[14] *Id.* P 47.

[15] *Id.*

[16] *See* Order No. 743-A, 134 FERC ¶ 61,210 at PP 40, 67, 102-103.

[17] *Id.* P 68.

[18] *Id.* P 69.

Commission left it to NERC in the first instance to determine if and how the seven factor test should be considered in differentiating between local distribution and transmission facilities for purposes of determining whether a facility should be classified as part of the bulk electric system.[19] Order No. 743-A re-emphasized that local distribution facilities are excluded from the definition of Bulk-Power System and, therefore, must be excluded from the definition of bulk electric system.[20]

D. NERC's Petitions

12. On January 25, 2012, NERC submitted two petitions pursuant to the directives in Order No. 743: (1) NERC's proposed revision to the definition of "bulk electric system" which includes provisions to include and exclude facilities from the "core" definition and (2) revisions to NERC's Rules of Procedure to add a procedure creating an exception process to classify or de-classify a facility as part of the "bulk electric system." In this NOPR, we address both petitions.[21]

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[19] *Id.* P 70.

[20] *Id.* PP 25, 58.

[21] "Exclusion" refers to configurations of elements NERC has identified within the revised definition of bulk electric system that should not be included in the bulk electric system. In contrast, an "exception" refers to an element that falls within the bulk electric system definition but is found not to be necessary for the operation of the grid through the proposed exception process, or an element that an element that falls outside of the bulk electric system definition but is found through the exception process should be part of the bulk electric system. Thus, an "exception" may result in adding elements to, or removing elements from, the definition of bulk electric system. Also, NERC uses the term "exception" rather than the term "exemption" used in Order No. 743. *See* Order No. 743, 133 FERC ¶ 61,150 at P 115.

1. Revised Definition of Bulk Electric System

13. In Docket No. RM12-06-000, NERC filed a petition requesting Commission approval of a revised definition of "bulk electric system" in the NERC Glossary (NERC BES Petition). As explained below, the definition consists of a "core" definition and a list of facilities configurations that will be included or excluded from the "core" definition. NERC also requests approval of the proposed "Detailed Information to Support an Exception Request" form as satisfying the requirement in Order No. 743 that NERC develop "technical criteria" to address exception requests.[22] Finally, NERC requests Commission approval of its plan for implementation of the revised definition of "bulk electric system."

a. "Core" Definition of Bulk Electric System

14. NERC proposes the following "core" definition of bulk electric system:

> Unless modified by the [inclusion and exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.[23]

15. NERC states that the core definition eliminates regional discretion and establishes a clear, bright-line based on a 100 kV threshold. NERC states that the core definition

[22] The Detailed Information to Support an Exception Request is part of the exception process even though NERC filed it as part of the BES Petition. *See* NERC BES Petition at 25-26. Thus, the Commission will address the Detailed Information in the context of the NERC BES Petition rather than in the section of this NOPR addressing the exception procedure petition.

[23] *Id*. at 13.

places within the bulk electric system "all Transmission Elements operated at 100 kV or above, and all Real Power and Reactive Power resources connected at 100 kV or above," while establishing an express exclusion for facilities used in the local distribution of electrical energy.[24] NERC states that the revised definition deletes the phrase "[a]s defined by the Regional Reliability Organization" that is included in the current definition, eliminating the express basis for regional discretion.[25] NERC explains that the core definition includes the 100 kV criterion as a bright-line threshold, rather than as a general guideline, by eliminating the phrase "generally operated at" found in the current definition.[26]

16. NERC also explains that, while the current definition includes the phrase "associated equipment," and the revised definition does not, "associated equipment" is included in the revised definition by the use of the term "Transmission Elements" included in the revised core definition. NERC states that the NERC Glossary defines "Transmission" as "[a]n interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems;"[27] and

[24] *Id.* at 16. The current definition and Order No. 743 use the term "facility." NERC proposes to use the term "Element" as used in the NERC Glossary.

[25] *Id.* at 15.

[26] *Id.* at 16.

[27] *Id.* at 15 n.13.

defines "Elements" as, "[a]ny electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components."[28]

17. NERC states that the revised definition satisfies the Commission's directives and addresses the technical and policy concerns expressed in Order Nos. 743 and 743-A. According to NERC, the explicit basis of authority for Regional Entity discretion in the current definition is eliminated. In addition, NERC states that the core definition establishes specific threshold criteria rather than general guidelines of facilities operated or connected at or above 100 kV. Further, NERC states that the core definition in combination with the specific inclusions and exclusions provides a detailed set of criteria that can be applied on a uniform, consistent basis across all regions, eliminates ambiguity, and eliminates the potential for discretion and subjectivity in determining what facilities are part of or not part of the bulk electric system.

b. Inclusions and Exclusions to the Definition of Bulk Electric System

18. NERC states that, as part of the revised definition, NERC developed inclusions and exclusions to eliminate discretion in application of the revised "bulk electric system" definition. NERC states that the inclusions address five specific facilities configurations to provide clarity that the facilities described in these configurations are included in the

[28] *Id.*

bulk electric system (unless the facilities are excluded based on one of the specific exclusions).[29] The five inclusions are:

> **Inclusions:**
>
> **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3.
>
> **I2** - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.
>
> **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
>
> **I4** - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.
>
> **I5** - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

19. NERC explains that the facilities described in inclusions I1, I2, I4, and I5 are each operated or connected at or above 100 kV. NERC states that inclusion I3 encompasses blackstart resources identified in a transmission operator's restoration plan, which are necessary for the operation of the interconnection transmission system and should be

[29] *Id.* at 16.

included in the bulk electric system regardless of their size (MVA) or the voltage at which they are connected. NERC states that the inclusions will further reduce the potential for the exercise of discretion and subjectivity to exclude such configurations from the bulk electric system.

20. According to NERC, inclusion I1 includes transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under exclusion E1 or E3 (discussed later). NERC states that transformers operating at 100 kV or higher are part of the existing definition, but since transformers have windings operating at different voltages, and multiple windings in some circumstances, clarification was required to explicitly identify which transformers are included in the bulk electric system.

21. Inclusion I2 addresses generating resources with a gross individual nameplate rating greater than 20 MVA or a gross plant/facility aggregate nameplate rating greater than 75 MVA. According to NERC, inclusion I2 includes in the bulk electric system the generator terminals through the high-side of the step-up transformers connected at a voltage of 100 kV or above. NERC states that this inclusion mirrors the text of the NERC Registry Criteria (Appendix 5B of the NERC Rules of Procedure) for generating units.[30] NERC states that a "basic tenet that was followed in developing the [revised

[30] *Id.* at 17 (citing section III.c.1 and III.c.2 of Appendix 5B of the Rules of Procedure).

definition] was to avoid changes to Registrations…if such changes are not technically required for the [revised definition] to be complete."[31]

22. As noted above, inclusion I3 includes blackstart resources identified in the transmission operator's restoration plan in the bulk electric system.

23. Inclusion I4 includes dispersed power producing resources with gross aggregate capacity nameplate rating greater than 75 MVA which utilize a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above. NERC states that this inclusion was added to accommodate the effects of variable generation on the bulk electric system.

24. Inclusion I5 addresses static or dynamic devices (excluding generators) dedicated to supplying or absorbing reactive power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in inclusion I1. NERC states that this inclusion is the technical equivalent of inclusion I2 for reactive power devices.

25. NERC states that the four exclusions identify facilities configurations that should not be included in the bulk electric system.[32] Generally, the exclusions address radial systems, behind-the-meter generation and local networks that distribute power to load. The four exclusions are:

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[31] *Id.* at 17.

[32] *Id.* at 18.

Exclusions:

E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

E2 - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

E3 - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk-power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk-power transfer across the interconnected system. The LN is characterized by all of the following:

a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

> b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
>
> c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).
>
> **E4** – Reactive Power devices owned and operated by the retail customer solely for its own use.
> Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

26. Exclusion E1 provides detailed criteria for determining which facilities are properly excluded from the bulk electric system as radial facilities, which NERC states is intended to enhance the clarity of the radial facilities exclusion. NERC explains that criteria "b" and "c" of exclusion E1 identify the maximum amount of generation allowed on the radial facility while still qualifying for the radial facilities exclusion (aggregate capacity less than or equal to 75 MVA). NERC indicates that this exclusion addresses the circumstances of small utilities (including municipal utilities and cooperatives). According to NERC, "the maximum amount of generation allowed on the radial facility is sufficient to allow small utilities to continue to provide service options that support reliability of the interconnected transmission network, while not operating to exclude larger generators from the [bulk electric system]."[33] Further, NERC states, that the maximum amount of generation allowed on the radial facility per criteria "b" and "c" is

[33] *Id*. at 19.

consistent with the aggregate capacity threshold presently provided in the Registry Criteria for registration as a generator owner or generator operator (75 MVA gross nameplate rating).

27. With respect to the "normally open switch" note at the end of exclusion E1, NERC explains that this note is intended to address a common network configuration "in which two separate sets of facilities that, each standing alone, would be recognized as radial systems and not included in the bulk electric system are connected by a 'normally open switch' – *i.e.*, a switch that is set to the open position – for reliability purposes."[34] NERC states that a switch in this configuration is installed by entities to provide greater reliability to their end-use customers. According to NERC, scheduled maintenance activities on a radial line, or an unscheduled outage impacting the single point of supply to the radial line, could cause the disruption of power supply to the end-use customers served by the line, unless the entity has the ability to temporarily switch to another feed.[35] NERC states that the entity's operating procedures dictate how and when to operate such a normally open switch. NERC explains that an entity does not arbitrarily close the normally open switch placed in this configuration. Rather, the entity closes the "normally open" switch to maintain reliability of service to its end-use customers served

[34] *Id.*

[35] As explained below, the switch, though normally open, could be closed in such circumstances to allow the affected radial line to serve load by relying on another line through the closed switch.

from the affected radial line. NERC believes that facilities that otherwise meet the criteria for the radial system exclusion in exclusion E1 should not be included in the bulk electric system solely because the entity maintains a switch of this type, which is normally open, between sets of radial facilities. NERC states that for a set of radial facilities that are connected by a switch to qualify for the radial exclusion under exclusion E1, the switch must be identified as "normally open" on "source documents such as, prints or one-line diagrams and must in fact be normally set in the open position."[36]

28. NERC states that subjecting two sets of radial facilities that are normally unconnected to each other because the switch between them is open to the Reliability Standards during the limited time periods when the switch is closed for maintenance-related or outage-related circumstances would be fundamentally impractical and unworkable (from both the entity's perspective and the ERO's perspective).[37] NERC explains that this note will prevent numerous exception requests because this configuration is common.

29. According to NERC, exclusion E2 excludes a generating unit or units on the customer's side of the retail meter that serves all or part of the retail load subject to two conditions. First, the net capacity provided by the generating unit does not exceed 75 MVA. Second, standby, back-up, and maintenance power services are provided to the

[36] *Id*. at 20 n. 26. NERC provides other examples of source documents such as diagrams displayed within an energy management system or a SCADA system.

[37] *Id*. at 20-21.

generating unit or the retail load by a balancing authority, or pursuant to a binding obligation with a generator owner or generator operator, or under terms approved by the applicable regulatory authority. NERC states that these generating units are not necessary for the operation of the interconnected transmission network and, therefore, do not need to be included in the definition because they serve a single retail load, provide a limited amount of capacity to the bulk electric system, and are fully backed up by other resources.[38]

30. NERC explains that exclusion E3, the "local network" exclusion, encompasses local networks of transmission elements operated at between 100 kV and 300 kV "that distribute power to load rather than transfer bulk power across the interconnected system."[39] NERC explains that "[t]he purpose of local networks is to provide local distribution service, not to provide transfer capacity for the interconnected transmission network."[40] According to NERC, a network that supports distribution and does not accommodate bulk-power transfers across the interconnected system should not be included in the bulk electric system. NERC also states that the "detailed conditions established in exclusion E3 are sufficient to ensure that such qualifying local networks

[38] *Id*. at 21.

[39] *Id*. at 22.

[40] *Id*.

are being used exclusively for local distribution purposes."[41] NERC adds that facilities used for the local distribution of electric energy are expressly excluded from the bulk electric system by the core definition as well as by the local network exclusion.

31. Exclusion E4 encompasses reactive power devices owned and operated by a retail customer solely for its own use. NERC explains that exclusion E4 is the technical equivalent of exclusion E2 for reactive power devices.

c. Detailed Information to Support an Exception Request

32. In Order No. 743, the Commission directed NERC to develop a set of technical criteria to use in addressing requests for exceptions to the definition of the bulk electric system.[42] NERC states that it would be "more feasible to develop a common set of data and information that could be used by the Regional Entities and NERC to evaluate exception requests" than to develop the detailed criteria.[43] The Detailed Information Form contains the common set of data that entities seeking an exception must submit with every exception request. NERC indicates that the Detailed Information Form represents an equal and effective alternative approach to developing a substantive set of technical criteria for granting and rejecting exception requests required in Order

[41] *Id*. at 23. *See also id*. at Exh. G (Technical Justification Paper for "Local Network Exclusion") at 2 (LN Technical Paper).

[42] Order No. 743, 133 FERC ¶ 61,150 at P 115 (stating "NERC should develop an exemption process that includes clear, objective, transparent and uniformly applicable criteria for the exemption of facilities that are not necessary for operating the grid.").

[43] NERC BES Petition at 26.

No. 743.[44] Thus, NERC asks the Commission to approve the Detailed Information Form as satisfying the Commission's technical concerns expressed in Order No. 743 with respect to the need for criteria to approve or disapprove exception requests.

33. The Detailed Information Form specifies that all exception requests include a one-line breaker diagram identifying the element for which the exception is requested and data and studies to support the submittal. NERC states that the studies should be based on an Interconnection-wide base case to reflect the electrical characteristics and system topology. The studies should clearly document all assumptions used, address key performance measures of bulk electric system reliability through steady state power flow, and contain a transient stability analysis as necessary to support the entity's request. NERC notes that the applicant remains responsible for providing sufficient information and argument to justify the exception request.[45]

34. According to NERC, the information that an applicant may submit in support of an exception request is not limited to the Detailed Information Form. Rather, an applicant is expected to submit all relevant data, studies and other information that supports the exception request. Further, the Regional Entity and NERC may ask an applicant to provide other data and studies in addition to the Detailed Information Form.[46]

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[44] *Id.* at 26, 32 (citing Order No. 743, 133 FERC ¶ 61,150 at P 115).

[45] *Id.* at 30.

[46] *Id.* at 27 n.32.

d. Proposed Implementation Plan for Revised Definition of "Bulk Electric System"

35. NERC requests that the revised definition "should be effective on the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, the revised [bulk electric system definition] should go into effect on the first day of the second calendar quarter after its adoption by the NERC Board.[47] The existing definition would be retired at midnight of the day immediately prior to the effective date of the revised definition in the jurisdiction in which the revised definition is becoming effective. NERC states that the proposed effective date is appropriate to provide a reasonable time between the date of regulatory approval, which is not under the control of NERC or the industry, and the effective date of the revised BES definition.[48]

36. NERC also requests that compliance obligations for all elements newly-identified to be included in the bulk electric system based on the revised definition should begin twenty-four months after the applicable effective date of the revised definition. NERC notes that the Commission stated in Order Nos. 743 and 743-A that the transition period should not exceed 18 months from the date of Commission approval of the revised definition, unless the Commission approved a longer transition period based on specific justification. NERC believes that a "somewhat longer transition period" is necessary in

[47] *Id.* at 34.

[48] *Id.*

light of the actions that will need to be completed in connection with the revised definition. NERC notes that in the United States, the proposed transition period will be between a minimum of approximately twenty-seven months and a maximum of thirty months from the date of Commission approval, depending on the date of Commission approval."[49] NERC states that sufficient time is needed: (1) to implement transition plans to accommodate any changes resulting from the revised definition; (2) for entities to file for exceptions, and for the Regional Entities and NERC to process those exceptions to a final determination, pursuant to the proposed exception process; and (3) for owners of facilities and elements that are newly-included in the bulk electric system based on the definition to train their personnel on compliance with the Reliability Standards applicable to the newly-included facilities and elements, so that these entities can achieve compliance with applicable Reliability Standards by the end of the transition period.

2. NERC Petition for Approval of Revisions to Rules of Procedure to Adopt a Bulk Electric System Exception Process

a. Changes to NERC's Rules of Procedure

37. In Docket No. RM12-7-000, NERC filed proposed revisions to its Rules of Procedure for the purpose of adopting a procedure for entities to obtain an exception from the definition of bulk electric system (NERC ROP Petition). NERC states that the proposed exception process, which is a mechanism to add elements to, and remove

[49] *Id.* at 35.

elements from, the bulk electric system, addresses the concerns raised in Order No. 743 with respect to the current processes for determining what facilities are part of the bulk electric system and what facilities are not.[50] NERC also states that the exception process "provides for decisions to approve or disapprove exception requests to be made by NERC, rather than by the Regional Entities, thereby eliminating the potential for inconsistency and subjectivity that the Commission was concerned [about, which] was created by having decisions as to what facilities are included in or excluded from the BES made at the Regional Entity level."[51] NERC proposes to add section 509 (Exceptions to the Definition of the Bulk Electric System), section 1703 (Challenges to NERC Determinations of BES Exception Requests) and Appendix 5C (Procedure for Requesting and Receiving an Exception to the NERC Definition of Bulk Electric System) to NERC's Rules of Procedure. The NERC ROP Petition also includes proposed conforming revisions to other Rules of Procedure, including revisions to sections 302.2, 501.1.4.4, 804, 1102.2, and 1701 and appendices 2, 3D, 4B, 5B, 6, and 8, which NERC states are necessary in light of the revised definition and the exception process.

Section 509 of the Rules of Procedure

38. NERC states that proposed section 509 establishes a procedure, which is contained in a new Appendix 5C to the Rules of Procedure, for an entity to request that an element

[50] NERC ROP Petition at 4.

[51] *Id.* (footnote omitted).

that falls outside of the definition of the bulk electric system be treated as part of the bulk electric system and for an entity to request that an element that falls within the definition of the bulk electric system not be treated as part of the bulk electric system:

> An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside the definition of the Bulk Electric System should be considered a part of the Bulk Electric System.[52]

NERC explains that the exception process is "not intended to be used to resolve ambiguous situations," i.e. the exception process is only available after an initial determination has been made regarding whether an element is part of or not part of the bulk electric system through the application of the definition to the element.[53]

Appendix 5C to the Rules of Procedure

39. NERC explains that proposed Appendix 5C sets forth the detailed procedures for obtaining an exception to include an element in, or remove an element from, the bulk electric system.[54] The exception process involves three steps.[55] First, an entity applies the bulk electric system definition to a transmission element to determine its status. If the

[52] *Id.* at 10.

[53] *Id.* at 10-11.

[54] *Id.* at 11. *See* also section D.1.c above.

[55] *Id.* at 13-14.

entity believes that the element, contrary to its characterization based on the definition, should either be treated, or not be treated, as part of the bulk electric system, the entity may submit an exception request to the Regional Entity in which the element is located. Second, the Regional Entity screens the request to determine whether the application meets the filing criteria and, if so, reviews the application and makes a recommendation to NERC whether to approve or deny the request. Third, the NERC President decides whether to approve or deny the exception request after considering the opinion provided by a NERC review panel.[56] If the entity does not agree with the NERC President's decision, it may appeal the decision to the NERC Board of Trustees Compliance Committee (Compliance Committee) who is the final arbiter of the request.

40. According to NERC, if the Regional Entity denies the exception request based on the initial screening but the applicant believes the exception request is proper and complete, the applicant may appeal the rejection directly to NERC.

41. NERC explains that the proposed exception process will allow NERC to provide consistent determinations on exception requests submitted from different regions involving the same or similar facts and circumstances, and will allow NERC to take into account the aggregate impact on the bulk electric system of approving or disapproving all of the exception requests. Finally, the exception process includes provisions for reporting information that may alter the status of an approved exception, verifying whether an

[56] The panel will have at least three members. NERC ROP Petition at 14.

exception continues to be warranted, and revoking an exception that is no longer warranted.

42. The proposed exception process includes provisions for obtaining exceptions both for inclusion in and exclusion from the bulk electric system. NERC identifies the entities that are eligible to submit exception requests. Specifically, the owner of an element may submit a request to include the element in, or remove it from, the bulk electric system.[57] A Regional Entity, planning authority, reliability coordinator, transmission operator, transmission planner, or balancing authority that has (or will have upon inclusion in the bulk electric system) the elements covered by an exception request within its scope of responsibility may submit an exception request for the inclusion in the bulk electric system of an element or elements owned by a registered entity. NERC states that only a Regional Entity may submit an exception request for the inclusion in the bulk electric system of an element owned by an owner that is not a registered entity.

43. Finally, NERC states that an exception request will be subject to review to verify continuing justification for the exception.[58] According to NERC, the proposed exception process requires an entity to notify the Regional Entity and NERC within 90 days after

[57] Section 5C of NERC's Rules of Procedure defines "owner" as "the owner(s) of an [e]lement or [e]lements that is or may be determined to be part of the [bulk electric system] as a result of either the application of the [bulk electric system] [d]efinition or an [e]xception, or another entity, such as an operator, authorized to act on behalf of the owner of the [e]lement or [e]lements in the context of an [e]xception [r]equest."

[58] *Id.* at 34 and Att. 1 at 17.

learning of any change of condition which would affect the basis for approving the exception request. NERC will then review the information and determine whether to direct the Regional Entity to perform a substantive review to verify continuing justification and issue a recommendation to NERC.[59] NERC also states that an entity must certify every 36 months to the appropriate Regional Entity that the basis for the exception request remains valid. In addition, the proposed exception process states that if the Regional Entity obtains information through means other than the submitting entity that indicates an exception may no longer be warranted, the Regional Entity must provide NERC with the information. NERC will review the information and determine whether to direct the Regional Entity to perform a substantive review to verify continuing justification and issue a recommendation to NERC.[60]

44. NERC states that the exception process establishes a process that (1) balances the need for effective and efficient administration with due process and clarity of expectations; (2) promotes consistency in determinations and eliminates Regional discretion by having all decisions on Exception Requests made at NERC; (3) provides for involvement of persons with applicable technical expertise in making decisions on ception Requests; and (4) should alleviate concerns about a "one-size-fits-all" approach.[61]

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[59] *Id.* at 34-35 and Att. 1 at 17.

[60] *Id.* at 35 and Att. 1 at 17.

[61] *Id.* at 17.

Section 1703 of the Rules of Procedure

45. NERC has also proposed to modify its Rules of Procedure to add a procedure for an entity to challenge the NERC decision on an exception request. The entity must file the challenge with the Compliance Committee within 30 days of the date of the NERC decision. The Compliance Committee must issue its decision within 90 days after the submission of the challenge, which the Compliance Committee may extend. NERC states that the Compliance Committee decision will be the final NERC decision on the exception request. In addition, the entity may appeal the final NERC decision to the Commission within 30 days following the date of the Compliance Committee's decision, or within such time period as the Commission's legal authority permits.

b. NERC's List of Facilities Granted Exceptions

46. In Order No. 743, the Commission stated that NERC should maintain a list of exempted facilities that can be made available to the Commission upon request.[62] NERC states that the proposed exception process does not include provisions for NERC to maintain a list of facilities that have received exceptions, as requested in Order No. 743, as this is an internal administrative matter for NERC to implement that does not need to be embedded in the Rules of Procedure.[63] NERC states it will develop a specific internal plan and procedures for maintaining a list of facilities for which exceptions have been granted.

[62] Order No. 743, 133 FERC ¶ 61,150 at P 117.

[63] NERC ROP Petition at 49.

47. NERC also notes that Regional Entities will maintain lists of elements within their regions for which exceptions have been granted, in order to monitor compliance with the requirement to submit periodic certifications pursuant to section 11.3 of Appendix 5C.[64]

II. Discussion

48. Pursuant to section 215(d) of the FPA we propose to approve NERC's revised definition of bulk electric system, including the specific inclusions and exclusions set forth in the definition, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed below, we believe that NERC's proposal satisfies the directives of Order No. 743 to develop modifications to the currently-effective definition of bulk electric system to ensure that the definition encompasses all facilities necessary for operating an interconnected transmission network and remove the Regional Entity discretion that currently allows for regional variations without review or oversight. We also believe NERC's proposed definition satisfies the Commission's technical concerns in Order No. 743 through the use of a bright-line 100 kV threshold, with specific inclusions and exclusions within the definition, for identifying bulk electric system elements and the establishment of an exception process for facilities that are not necessary for operating the interconnected transmission network. Further, we believe NERC's proposed definition improves clarity and transparency. Below, we discuss the

[64] *Id.*

proposed "core" bulk electric system definition as well as each bright-line inclusion and exclusion of the proposed definition.

49. While proposing to approve NERC's modified definition, we also seek additional explanation and comments regarding potential applications of the "core" definition, as well as the inclusions and exclusions. We believe that a common understanding of the proposed bulk electric system definition (1) promotes consistent application of the definition in identifying bulk electric system elements and facilities and (2) provides up-front clarity so as to minimize the need for future clarifications either formally through NERC's standards clarification process or case-specific in a compliance setting. Thus, we seek comment from NERC and other interested persons regarding the scenarios and applications of the NERC proposal, discussed below. Although we propose to approve the definition in this rulemaking, the responses to our questions are also intended to guide the Commission as to whether other action may be necessary, for example, directing NERC to develop a further modification to the core definition, inclusions or exclusions pursuant to section 215(d)(5) of the FPA.

50. Further, pursuant to section 215(f) of the FPA, we propose to approve the revisions to the NERC Rules of Procedure that establish an exception process to determine case-specific exceptions to the bulk electric system definition. NERC's proposal meets the section 215(f) standard of review for changes to the Rules of Procedure. The Detailed Information Form in the proposed rules identifies "base-line" information and data that any applicant must submit. Further, after Regional Entity input,

NERC makes the final decision on whether to grant an exception request, which better assures consistency of decisions across all regions.

51. In Order No. 743, the Commission stated that NERC should maintain a list of facilities included or excluded from the bulk electric system pursuant to the exception process.[65] NERC indicates that, while it plans to maintain such a list, maintaining the list is an internal NERC function and, thus, not included in NERC's proposed Rules of Procedure. To understand how NERC intends to comply with the directive from Order No. 743, we propose to require that NERC submit a compliance filing detailing its internal process for tracking exception requests.

52. Below, the Commission discusses (A) the "core" bulk electric system definition; (B) proposed inclusions and exclusions in the definition; (C) the case-specific exception process; (D) the Detailed Information Form; and (E) NERC's implementation plan.

A. The Commission Proposes to Approve the Core Definition of Bulk Electric System

53. The bulk electric system "core" definition developed by NERC states as follows:

> Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

54. In Order No. 743, the Commission found that "the current definition of bulk electric system is insufficient to ensure that all facilities necessary for operating an

[65] Order No. 743, 133 FERC ¶ 61,150 at P 117.

interconnected electric energy transmission network are included under the 'bulk electric system' rubric."[66] The Commission also stated that the "aim" of the final rule was to "eliminate inconsistencies across regions, eliminate the ambiguity created by the current discretion in NERC's definition of bulk electric system, provide a backstop review to ensure that any variations do not compromise reliability, and ensure that facilities that could significantly affect reliability are subject to mandatory rules."[67] The Commission stated that the one way to accomplish these goals is to eliminate the regional discretion in the current definition, and maintain the bright-line threshold that includes all facilities operated at or above 100 kV and establish an exception process and criteria for excluding facilities that are not necessary for the operation of the interconnected transmission network.[68]

55. It appears that NERC's proposal satisfies the objectives set forth in Order No. 743. The "core" definition, quoted above, establishes the fundamental threshold for inclusion of facilities in the bulk electric system as those that are operated at 100 kV or higher, if they are transmission elements, or are connected at 100 kV or higher, if they are real power or reactive power resources. The core definition also establishes a 100 kV criterion as a bright-line threshold, rather than as a general guideline as in the current

[66] Order No. 743, 133 FERC ¶ 61,150 at P 30.

[67] *Id.* P 2.

[68] *Id.*

definition, i.e., the phrase "generally operated at" in the current definition is eliminated. As NERC explains, the core definition also continues to capture equipment associated with the facilities included in the bulk electric system.[69]

56. Further, consistent with Order No. 743, NERC's proposed "bulk electric system" definition eliminates the phrase "as defined by the Regional Reliability Organization…." As a result, NERC's proposed definition will apply nation-wide. Thus, we believe NERC's proposal adequately addresses the concerns articulated in Order No. 743 regarding unfettered regional discretion and the need for a consistent approach satisfies the concerns regarding the elimination of inconsistencies across regions. The Commission seeks comment on whether the revised definition adequately eliminates subjectivity and regional variation as required in Order No. 743.[70]

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[69] The core definition includes all "Transmission Elements operated at or above 100 kV." As NERC explains in its petition, the NERC-defined term "Transmission" includes the phrase "associated equipment." The NERC Glossary defines "Transmission" as "[a]n interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Additionally, the Glossary defines "Elements" as "[a]ny electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components." We agree with NERC that while the new definition does not use the term "associated equipment," the phrase is included in the definition through the defined term "Transmission Elements."

[70] *Id.* PP 11-12, 57. The Commission notes that nothing in the immediate rulemaking proceeding should impact the application of available transmission capability (ATC) calculations as set for in Order No. 890. *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 196, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on*

(continued…)

57. Below, we seek comment regarding the exclusion of facilities used in local distribution.

Local Distribution

58. In Order No. 743, the Commission acknowledged that "Congress has specifically exempted 'facilities used in the local distribution of electric energy'" from the Bulk-Power System definition and that, because such facilities are exempted from the Bulk-Power System, they also are excluded from the bulk electric system.[71] The Commission also stated that, although local distribution facilities are excluded from the definition, it still is necessary to determine which facilities are local distribution, and which are transmission.[72] As the Commission stated in order No. 743-A, "[w]hether facilities are used in local distribution will in certain instances raise a question of fact, which the Commission has jurisdiction to determine." In Order No. 743, the Commission also recognized that NERC would need to establish whether a particular facility is local distribution or transmission, and directed NERC to develop a means, subject to

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reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009). Public utility transmission service providers (or their designate) have the obligation to comply in all respects with their Commission approved tariff. This requires that they must continue to use the applicable Reliability Standards to plan and operate both their bulk electric system and non-bulk electric system facilities included in their tariffs.

[71] Order No. 743, 133 FERC ¶ 61,150 at P 37.

[72] Order No. 743-A, 134 FERC ¶ 61,210 at P 67.

Commission approval, to make such a determination.[73] In Order No. 743-A the Commission clarified that

> the statement in Order No. 743, "determining where the line between 'transmission' and 'local distribution' lies … should be part of the exemption process the ERO develops" was intended to grant discretion to the ERO, as the entity with technical expertise, to develop criteria to determine how to differentiate between local distribution and transmission facilities in an objective, consistent, and transparent manner. … Once NERC develops and submits its proposal to the Commission, the Commission will, as part of its evaluation of the proposal, determine whether the process developed adequately differentiates between local distribution and transmission.
>
> We agree … that the Seven Factor Test could be relevant and possibly is a logical starting point for determining which facilities are local distribution for reliability purposes, while also allowing NERC flexibility in applying the test or developing an alternative approach as it deems necessary.[74]

59. In addressing what constitutes local distribution, NERC explains that the second sentence in the core definition, which excludes "facilities used in the local distribution of electric energy," is consistent with section 215(a)(1)(B) of the FPA and the Commission's regulations at 18 C.F.R. § 39.1 and as recognized in Order No. 743-A."[75] NERC states that "the core definition… establish[es] an express carve out for facilities used in the local distribution of electrical energy."[76] NERC also states that facilities for the local distribution of electric energy are expressly excluded from the bulk electric

[73] Order No. 743, 133 FERC ¶ 61,150 at P 37.

[74] Order No. 743-A, 134 FERC ¶ 61,210 at PP 68-69 (footnotes omitted).

[75] NERC BES Petition at 16.

[76] *Id.* at 22-23.

system by the core definition as well as by the local network exclusion, exclusion E3.[77] NERC adds that, while some stakeholders suggested that the Commission's seven-factor test should be employed to determine distribution facilities, the NERC drafting team "rejected this approach as the sole determination of distribution facilities, … [but] pointed out that such a test could be utilized by a Submitting Entity making an Exception Request but that other information should be supplied to support the request."[78]

60. The Commission seeks comment from NERC and the public regarding how the proposed definition is responsive to the Commission's directives in Order Nos. 743 and 743-A. Specifically, the Commission seeks comment on how NERC's proposal

[77] NERC's LN Technical Paper, Exhibit G of NERC's Petition, provides:

> In Order 743a, the Commission made it clear that facilities that are used in the local distribution of electric energy will be excluded from the Bulk Electric System. … In response to this facet of the Order, in developing the BES definition, the SDT has followed this guidance. Exclusion E3 was specifically designed to capture for exclusion those high voltage non-radial facilities being used for the local distribution of energy.
>
> The exclusion characteristics in items a, b, and c … serve to ensure that facilities excluded under the local network exclusion (E3) are not necessary for the reliable operation of the interconnected electric transmission network and are instead used in the local distribution of energy.
>
> *Id.*, Ex. G, at 2.

[78] NERC BES Petition at 49.

adequately differentiates between local distribution and transmission facilities in an objective, consistent, and transparent manner.[79]

B. The Commission Proposes to Approve the List of Inclusions and Exclusions in the Definition of Bulk Electric System

61. Along with the core definition, NERC's proposal provides specific inclusions and exclusions. The inclusions and exclusions provide added clarity regarding which elements are part of the bulk electric system as compared to the existing definition. For example, the inclusion of generating resources, blackstart resources and dispersed power producing resources provide additional information and granularity that assist in the identification of bulk electric system facilities or elements. However, we also have questions about how some of the inclusions and exclusions will be applied by NERC, Regional Entities and users, owners and operators of the Bulk-Power System. Through the responses to these questions we seek to better understand potential applications of the inclusions and exclusions, their effect on identifying the facilities or elements for bulk electric system reliability, and whether possible gaps exist.

[79] We note that an element that falls outside of the definition of bulk electric system is not necessarily local distribution.

1. Inclusions

a. Inclusion I1 (Transformers)

62. Inclusion I1 provides "[t]ransformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under [the radial system or local network exclusion]." NERC explains that:

> Transformers operating at 100 kV or higher are part of the existing definition, but since transformers have windings operating at different voltages, and multiple windings in some circumstances, clarification was required to explicitly identify which transformers are included in the BES. Inclusion I1 includes in the BES those transformers operating at 100 kV or higher on the primary winding and at least one secondary winding, so as to be in concert with the core definition.[80]

63. We believe that inclusion I1, with NERC's explanation, is a reasonable approach to identifying transformers that are appropriately included as part of the bulk electric system. However, circumstances may warrant inclusion of a particular transformer – through the proposed case-specific exception process - where a transformer is operated at 100 kV or higher on the primary winding but all secondary terminals are operated below 100 kV. The joint NERC and Commission staff report on the September 8, 2011, Arizona-Southern California blackout discusses how a 92 kV networked system experienced parallel flows from bulk electric system elements through two 230/92 kV

[80] NERC BES Petition at 17.

transformers.[81] The report explains that the reliability coordinator, transmission operators and balancing authorities did not consider certain sub-100 kV facilities, including two 230/92 kV transformers as bulk electric system elements. Consequently, when contingencies occurred on the bulk electric system on September 8, 2011, the reliability coordinator, transmission operators and balancing authorities were unaware that the contingencies adversely impacted the 230/92 kV transformers or how the loss of the transformers impacted system reliability.[82] The Commission seeks comment on whether these types of transformers, i.e., those that have a terminal operated at 100 kV or above on the high side and below 100 kV on the low side should be designated as part of the bulk electric system. If answered in the affirmative, the Commission seeks further comment whether the case-by-case exception process suffices, or a generic inclusion is appropriate to address the concerns identified in Order No. 743.

b. Inclusion I2 (Generating Resources)

64. Inclusion I2 provides:

> Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.

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[81] Arizona-Southern California Outages on September 8, 2011 – Causes and Recommendations at 96 (September 2011 Blackout Report), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

[82] *Id*. at 96-97.

According to NERC, this inclusion "mirrors" the text of the NERC *Registry Criteria* for generating units. NERC explains that the drafting team "found no technical rationale for changing at this time from the thresholds for generating resources presently specified in the … *Registry Criteria*."[83] Further, NERC states that, to provide clarity, the revised definition specifies that the bulk electric system "includes the generator terminals through the high-side of the step-up transformer connected at a voltage of 100 kV or above."[84]

65. We believe that Inclusion I2 provides useful granularity regarding the inclusion of generation resources as part of the bulk electric system. However, we seek comment regarding several aspects of inclusion I2. NERC's Registry Criteria thresholds for generators provides for the registration of "[i]ndividual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the Bulk Power System" or "[g]enerating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the Bulk Power System at a common bus with total generation above 75 MVA gross nameplate rating."[85] We agree that proposed inclusion I2 is consistent with the individual and aggregate nameplate rating thresholds set forth in the Registry Criteria.

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[83] NERC BES Petition at 17. NERC states "A basic tenet that was followed in developing the revised BES Definition was to avoid changes to Registrations due to the revised BES Definition if such changes are not technically required for the BES Definition to be complete." *Id.* (citing Order No. 743-A, 134 FERC ¶ 61,210 at P 102).

[84] NERC BES Petition at 17.

[85] Registry Criteria, III.c.1 and c.2 (Generator Owner/Operator).

We note, however, that the Registry Criteria and the proposed definition differ regarding the description of the connection point of the generating units and plants. While inclusion I2 specifies "generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above," the Registry Criteria specifies a "direct connection" to the Bulk-Power System. We seek comment whether inclusion I2 will result in a material change to registration of existing generating units due to the difference in the language regarding the connection point. In addition, we seek comment if, pursuant to inclusion I2, the following circumstances are included in the bulk electric system: a generating unit, with a gross individual nameplate rating greater 20 MVA connected through the high-side of the step-up transformer connected at a voltage of 100 kV or above *when the low side of the transformer is less than 100 kV.* How does this result differ for a generation resource with two or more step-up transformers where the last transformer in the series operates at 100 kV or above, for example, a 50 MVA generator first steps up through a 23 kV transformer on the low side and 69 kV on the high side and then immediately steps up through a second transformer at the same site with less than 100 kV on the low side and above 100 kV on the high side?

c. Inclusion I3 (Blackstart Resources Identified in the Transmission Operator's Restoration Plan)

66. Inclusion I3 identifies as part of the bulk electric system "Blackstart Resources identified in a Transmission Operator's restoration plan." NERC explains that blackstart resources are "vital" for the reliable operation of the bulk electric system and are included

"regardless of their size (MVA) or the voltage at which they are connected."[86] NERC further states that including blackstart resources is consistent with the *Registry Criteria*, which provide that "*any generator, regardless* of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan" is eligible for registration.[87]

67. We agree with NERC that inclusion of blackstart resources in the definition is vital to reliability and is an improvement to the definition. We seek clarification whether the term "restoration plan" refers to the system restoration plans required in the Emergency Preparedness and Operations (EOP) Reliability Standards or included in a Commission approved tariff.[88]

68. NERC states that first posting of the revised definition included "cranking paths" for blackstart resources due to a concern about "the possibility of having Blackstart Resources without a 'guaranteed' path" to the [bulk electric system]."[89] NERC explains

[86] NERC BES Petition at 18.

[87] *Id.* (emphasis added).

[88] Reliability Standard EOP-005-1, System Restoration Plans, requires a transmission operator to create "a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system."

[89] NERC BES Petition at 47. The NERC Glossary defines "Cranking Path" as "[a] portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units." *See also* the Regional Bulk Electric System Definition Coordination Group concept paper that recommends including the designated cranking paths for the blackstart

(continued…)

that "a number of commenters complained that this was improperly bringing distribution level Elements into the [bulk electric system], as many Cranking Paths are at the distribution level" and "also pointed out that this was an illusory proposition as intended Cranking Paths are not always the ones used in actual restoration."[90] As a result of the industry feedback, NERC deleted cranking paths from the revised definition with the understanding that the issue would be revisited in Phase 2 of the BES project. According to NERC, "this approach would maintain status quo on this topic, consistent with Order Nos. 743 and 743-A, while providing for a full discussion and consideration of the issue in a less time constrained environment."[91] ."[92] Subsequently, however, the topic of cranking paths was deleted from the scope of the Phase 2 BES project.[93] In light of the

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resources available at http://www.nerc.com/docs/standards/sar/Project_2010-17_Concept_Paper.pdf.

[90] *Id*.

[91] *Id*. NERC's Project 2010-17, the "Phase 2 BES Project."

[92] *Id*. NERC's Project 2010-17, the "Phase 2 BES Project."

[93] The February 21-23, 2012 meeting notes from the Project 2010-17 Definition of Bulk Electric System Phase 2 Standard Drafting Team states that "the SDT decided to delete the Cranking Path reference in the [Phase 2] SAR." The reasons for the deletion included "that Cranking Paths reach down into distribution and thus shouldn't be included in the definition," and "that this issue was debated in Phase 1 and resolution was obtained," and "that Cranking Paths were only needed when an entity was in restoration mode so it wasn't needed in the definition." However, the same document states some commenters believe "that Cranking Paths were only needed when an entity was in restoration …and…that this was a reason to have it in the definition." *See* Meeting Notes from the Project 2010-17 Definition of Bulk Electric System Phase 2 Standard Drafting Team, February 21-23, 2012, at Page 5, *available at*

(continued…)

decision not to further pursue a possible revision to the bulk electric system definition pertaining to cranking paths, the Commission is concerned whether a reliability gap exists with regard to cranking paths. Cranking paths constitute a basic element of system restoration, and it is unclear whether reliability can be adequately maintained when blackstart generators are defined as part of the bulk electric system but not the transmission paths that are used to deliver the energy from blackstart generators to the integrated transmission system. We also recognize that cranking paths may implicate facilities used in local distribution. Accordingly, we seek comment on whether a reliability gap may exist with regard to cranking paths and, if so, what potential approaches are appropriate to remove the gap. We also seek comment on the appropriate role, if any, of state regulators in ensuring that energy from blackstart generation is reliably delivered through cranking paths to restart the system after an event.

d. Inclusion I4 (Dispersed Power Producing Resources)

69. Inclusion I4 identifies as part of the bulk electric system:

> Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

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http://www.nerc.com/docs/standards/dt/Meeting_Notes-Project_2010-17_DBES-February_21-23,_2012.pdf.

70. NERC explains that this inclusion is intended "to accommodate the effects of variable generation" on the bulk electric system.[94] NERC further states that even though inclusion I4 could be considered subsumed in Inclusion I2 (generating resources), NERC believes it is appropriate "to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity."[95]

71. We believe that inclusion I4 provides useful granularity in the bulk electric system definition. To better understand the application of inclusion I4, we seek comment whether this provision includes as part of the bulk electric system the individual elements (from each energy-producing resource at the site through the collector system to the common point at a voltage of 100 kV or above) used to aggregate the capacity and any step-up transformers used to connect the system to a common point at a voltage of 100 kV or above.

e. Inclusion I5 (Static or Dynamic Reactive Power Devices)

72. Inclusion I5 identifies as part of the bulk electric system:

> Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

[94] NERC BES Petition at 18.

[95] *Id*.

NERC explains that this inclusion is the technical equivalent of inclusion I2 (generating resources), for reactive power devices and points out that the existing definition is unclear as to how these devices are treated. [96] NERC states inclusion I5 provides clarity by "providing specific criteria for Reactive Power devices, thereby further limiting subjectivity and the potential for discretion" in the application of the revised definition.[97]

73. The Commission agrees with NERC that this inclusion adds clarity to the application of the bulk electric system definition by providing specific criteria for reactive power devices. For cases where the reactive power device is connected through a transformer designated in inclusion I1, we seek comment on whether both the reactive power device and the transmission elements connecting the reactive power device to the transformer are included as part of the bulk electric system pursuant to inclusion I5.

2. Exclusions

74. NERC states that the proposed definition identifies four facilities configurations that should not be included in the bulk electric system: (1) radial systems, (2) behind-the-meter generating units, (3) local networks, and (4) retail customer reactive power devices.

75. We agree that the proposed definition's exclusions provide clarity and granularity. For example, the exclusion of generating units on the customer's side of the retail meter that serves all or part of the retail load (exclusion E2) and the exclusion for reactive power devices owned and operated by a retail customer for its own use (exclusion E4)

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[96] *Id.*

[97] *Id.*

provide reasonable limitations on bulk electric system elements. While we believe that the exclusions provide added clarity, we also seek comment on certain aspects of exclusions E1 and E3 to ensure a more complete understanding of their application.

a. Exclusion E1 (Radial Systems)

76. Exclusion E1 provides as follows:

> Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
>
> a) Only serves Load. Or,
> b) Only includes generation resources, not identified in Inclusion I3,
> with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
> c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).
>
> Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

NERC states that radial facilities are excluded under the currently effective bulk electric system definition, and the detailed criteria in the revised definition provide enhanced clarity.[98] We seek comment on our understanding and NERC's explanation of exclusion E1 in order for the Commission to ensure application of exclusion E1 is consistent. Also, we seek comment to determine if the configurations covered by Conditions (a), (b), or (c) of exclusion E1 remove from the bulk electric system generation connected to a radial

[98] *Id.*

system that otherwise satisfies inclusion I2. The Commission would like to ensure that the conditions in exclusion E1 will not lead to conflicting results when applying inclusion I2 and exclusion E1.

77. As stated above, the radial exclusion applies to "a group of contiguous *transmission* Elements that emanates from a single point of connection of 100 kV or higher.…" While the term "Elements" includes the term generator,[99] the use of the term "transmission" before "Elements" indicates that exclusion E1 applies only to transmission elements. The phrase "transmission Elements" in this provision does not apply to generating resources that are bulk electric system resources pursuant to inclusion I2 (generating resources), connected to a radial line operated at 100 kV above.[100]

[99] "Element" is defined in the NERC Glossary as "[a]ny electrical device with terminals that may be connected to other electrical devices *such as a generator*, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components." (emphasis added).

[100] Our understanding comports with the NERC standard drafting team's explanation in response to industry comments that generation resources connected within the radial system are not excluded pursuant to exclusion E1. *See* NERC BES Petition, Exh. D, Consideration of Comments Report, at 223 (stating that "Exclusion E1 is an exclusion for the contiguous transmission Elements connected at or above 100 kV. Generation resources connected within the radial system are qualifiers for this exclusion.").

i. Definition of 'Radial Systems' and Condition (a) - Radials only Serving Load

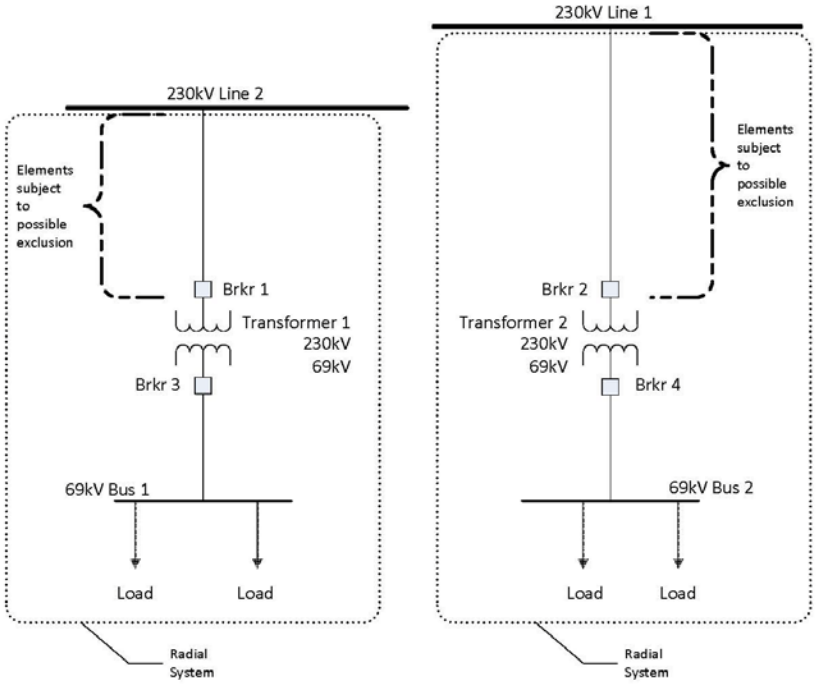
78. NERC stated that it developed exclusion E1 to provide enhanced clarity as compared to the existing definition.[101] Exclusion E1 defines the term 'radial systems' as "a group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher." The Commission seeks comment on how NERC's proposal would be applied in the three scenarios described below.

79. Figure 1 below depicts facilities configurations in which all of the 230 kV and 69 kV transmission elements emanate from a single point of connection of 100 kV or higher. The Commission seeks comment on whether each of the radial systems shown in figure 1, the 230 kV elements above each transformer to the point of connection to each 230 kV line, respectively, are excluded from the bulk electric system pursuant to exclusion E1.

[101] NERC BES Petition at 18.

Figure 1

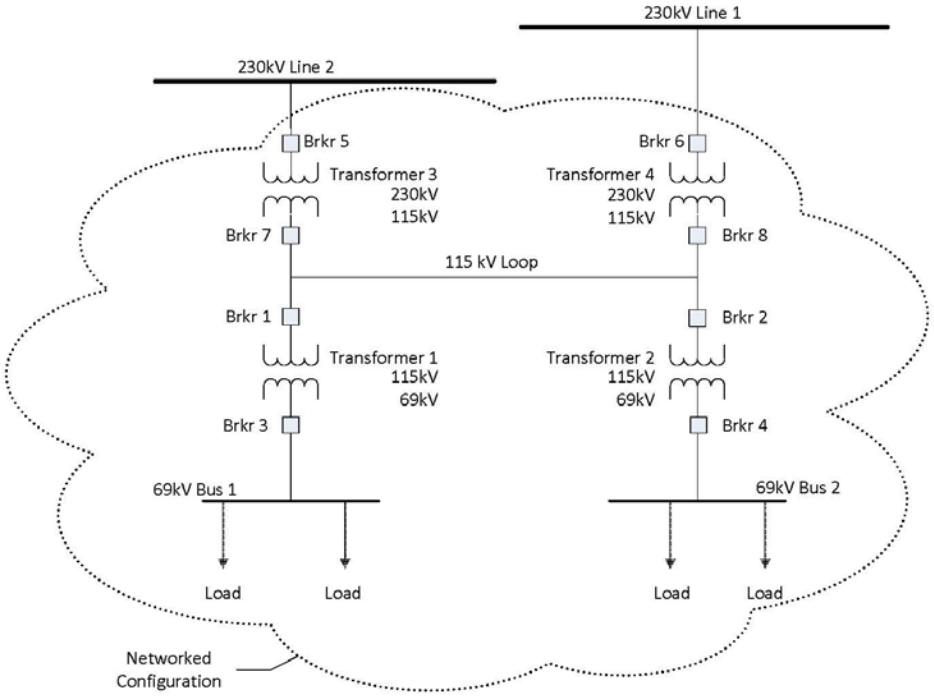
Two Radial Systems Eligible for Exclusion E1



80. Another scenario shown in figure 2 below depicts a configuration containing a 115 kV loop, with the configuration emanating from two points of connection of 100 kV or higher. We seek comment whether, in this configuration, the 115 kV and 230 kV elements above Transformers 1 and 2 to the points of connection to the two 230 kV lines would be excluded from the bulk electric system pursuant to exclusion E1. Is the configuration shown in figure 2 more appropriately analyzed pursuant to the "local network" exclusion E3 and, if so, what if any elements operated at or above 100 kV would be excluded pursuant to exclusion E3?

Figure 2

Networked Configuration w/115 kV Loop

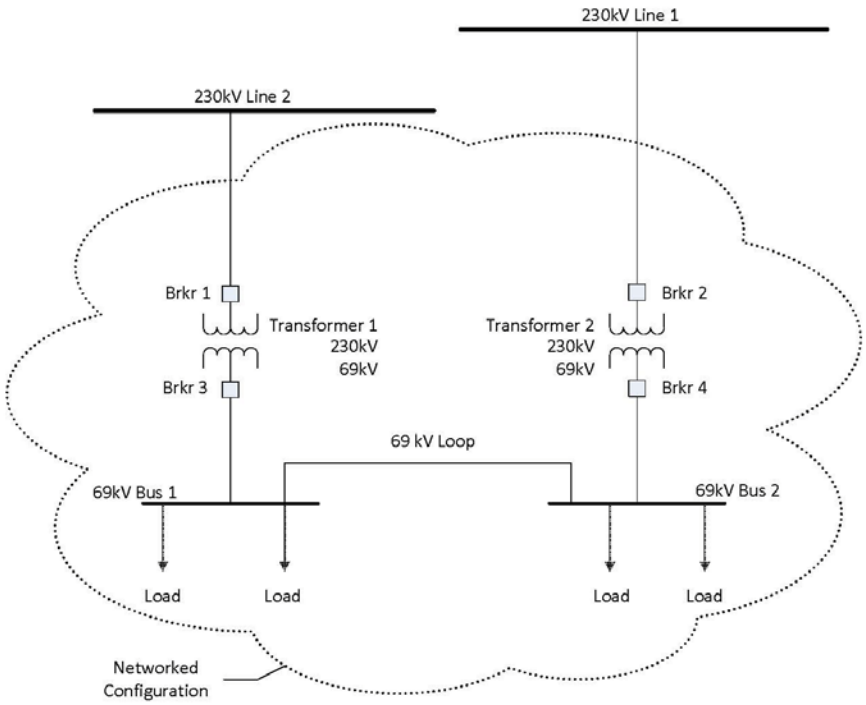


81. The Commission agrees with NERC that 'radial systems' only serving load and emanating from a single point of connection of 100 kV or higher should be excluded from the bulk electric system. The Commission is concerned that the exclusion could allow elements operating at 100 kV or higher in a configuration that emanates from two or more points of connection to be deemed "radial" even though the configuration remains contiguous through elements that are operated below 100 kV. For example, figure 3 below depicts a configuration with two points of connection of 100 kV or higher that are contiguous through a 69 kV loop. We seek comment on how to evaluate the configuration in figure 3 vis-à-vis the radial system definition and whether it is appropriate to examine the elements below 100 kV to determine if the configuration

meets the exclusion E1 definition for radial systems. In other words, does figure 3 depict a system emanating from two points of connection at 230 kV and, therefore, the 230 kV elements above the transformers to the points of connection to the two 230 kV lines would not be eligible for the exclusion E1 notwithstanding the connection below 100 kV?

Figure 3

Networked Configuration w/69 kV Loop



ii. Condition (b) – Radials With Limited Generation and Condition (c) – Radials With Limited Generation and Load

Condition (b) of exclusion E1 provides that a radial system is excluded if it "[o]nly includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating)." Proposed Condition (c) of exclusion E1, excludes radial systems "[w]here the radial system serves Load and

includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating)."

82. NERC states that Conditions (b) and (c) are "intended to address the circumstances of small utilities (including municipal utilities and cooperatives)."[102] The NERC BES Petition, including the Exhibit E record of development, does not further explain the need for, or the impact of, these proposed provisions. Accordingly, we seek comment regarding the specific circumstances that Conditions (b) and (c) are intended to address.

83. Because Condition (b) describes generation connected to a radial system with no load and Condition (c) describes generation connected to a radial system with generation and load, it appears that the power generated on these radial systems would, by design, be delivered or injected to the bulk electric system and transported to other markets. In this circumstance, it appears that a line 100 kV or above connected to a generator with a capacity 75 MVA or below would not be included in the bulk electric system. The Commission seeks comment on the appropriateness of excluding such radials.

iii. Normally Open Switches

84. Proposed exclusion E1 includes a "note" stating that a "normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion." NERC states that this note is intended to address a

[102] NERC BES Petition at 19.

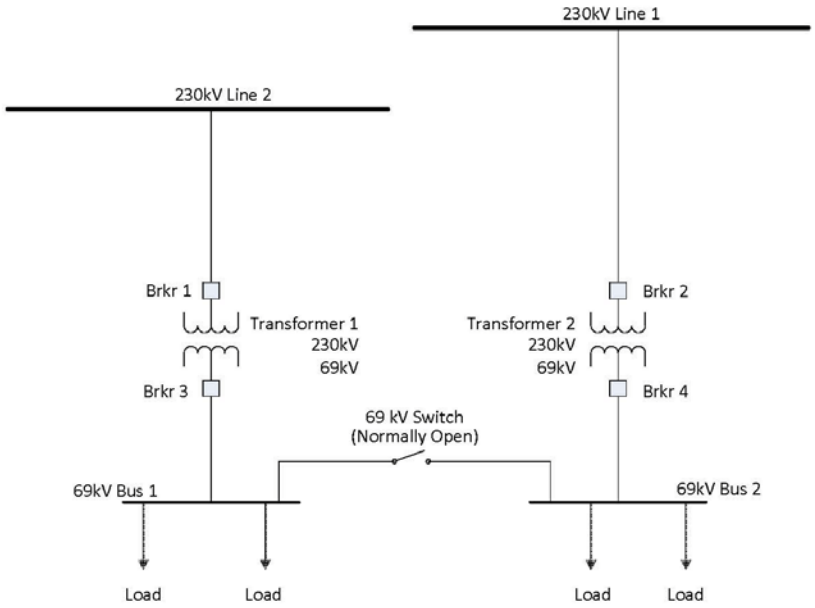
common network configuration in which two separate sets of facilities that, each standing alone, would be recognized as radial systems but are connected by a switch that is set to the open position for reliability purposes.[103]

85. NERC explains that these switches are installed by entities to provide greater reliability to their end-use customers. For example, when the entity schedules maintenance activities on a radial line or an unscheduled outage occurs that impacts a single point of supply to the radial line which could cause the disruption of power supply to the end-use customers served by the line, the switch allows the entity to use another feed on the connected radial line.

86. Figure 4 below illustrates a configuration with a normally open switch.

[103] NERC BES Petition at 19-20.

Figure 4
69 kV Networked Configuration with Normally Open Switch



NERC states that "[t]he concept that two sets of radial facilities that are normally unconnected to each other should be subject to…applicable Reliability Standards during the limited time periods when they are connected by the closing of the normally open switch in the maintenance-related or outage-related circumstances described above would be fundamentally impractical and unworkable (from both the entity's perspective and the ERO's perspective), and would misapprehend this very common, reliability-driven facilities configuration."[104]

87. NERC states that "a normally open switch" will be identified in documents such as prints or one-line diagrams and that "[t]he concept and usage of the 'normally open

[104] *Id.* at 20-21.

switch' in such configuration is well understood in the electric utility industry."[105] We seek comment on NERC's characterization and whether the phrase "normally open" is subject to interpretation or misunderstanding, or whether a "normally open" configuration is potentially difficult to oversee. Further, we seek comment on the need of transmission operators or other functional entities to study the system impacts of the closing of a "normally open" switch, or to take other steps to ensure awareness of the impacts of the loop that is created by the closing of the switch if the closed loop is not included as part of the bulk electric system.

b. Exclusion E2 (Behind the Meter Generation)

88. Exclusion E2 excludes "[a] generating unit or multiple generating units on the customer's side of the retail meter…." The Commission believes that this is an appropriate exclusion that provides additional clarity and granularity to the definition of bulk electric system.

c. Exclusion E3 (Local Networks)

89. As noted above, we believe that a common understanding of the exclusions promotes consistent application of the definition in identifying bulk electric system elements. In particular, as discussed in greater detail below, we seek comment on the following issues with respect to the application of exclusion E3: (1) whether generation resources are excluded by this exclusion; (2) how the exclusion applies to a looped lower

[105] *Id.* at 19.

voltage system; (3) whether the 300 kV ceiling is appropriate for the application of the exclusion; (4) whether the prohibition for generation produced inside a local network is not transporting power to other markets outside the local network applies in both normal and emergency operating conditions.

90. Exclusion E3 defines the term local networks as:

> A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk-power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk-power transfer across the interconnected system.

Exclusion E3 also identifies three conditions that must be satisfied for the exclusion to apply: (a) limit on connected generation to 75 MVA aggregate capacity of non-retail generation (gross nameplate rating); (b) power flows only into the local network and does not transfer through the 'local network'; and (c) the local network is not part of a flowgate or transfer path.

91. NERC states the design and operation of local networks is such that at the point of connection with the interconnected transmission network is similar to that of a radial facility, in particular that power always flows in a direction from the interconnected transmission network into the local network.[106] Further, according to NERC, "[l]ocal

[106] NERC BES Petition at 22.

networks provide local electrical distribution service and are not planned, designed or operated to benefit or support the balance of the interconnected transmission network."[107]

92. Similar to our discussion of the definition of 'radial systems' in exclusion E1, the exclusion E3 local network exclusion applies to transmission Elements, but does not apply to generation resources connected to a local network that otherwise satisfy inclusion I2.

93. NERC states in the LN Technical Paper, that "Exclusion E3 was specifically designed to capture for exclusion those high voltage non-radial facilities being used for the local distribution of energy."[108] The paper further provides:

> Their [local network] design and operation is such that at the point of connection with the interconnected electric transmission network, their effect on that network is similar to that of a radial facility, particularly in that flow always moves in a direction that is from the BES into the facility. Any distribution of parallel flows into the local network from the BES, as governed by the fundamentals of parallel electric circuits, is negligible, and, more importantly, is overcome by the Load served by the local network, thereby ensuring that the net actual power flow direction will always be into the local network at all interface points. The presence of a local network is not for the operability of the interconnected electric transmission network; neither will the local network's separation or retirement diminish the reliability of the interconnected electric transmission network."[109]

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[107] *Id.*

[108] NERC BES Petition, Exhibit G at 2.

[109] *Id.*

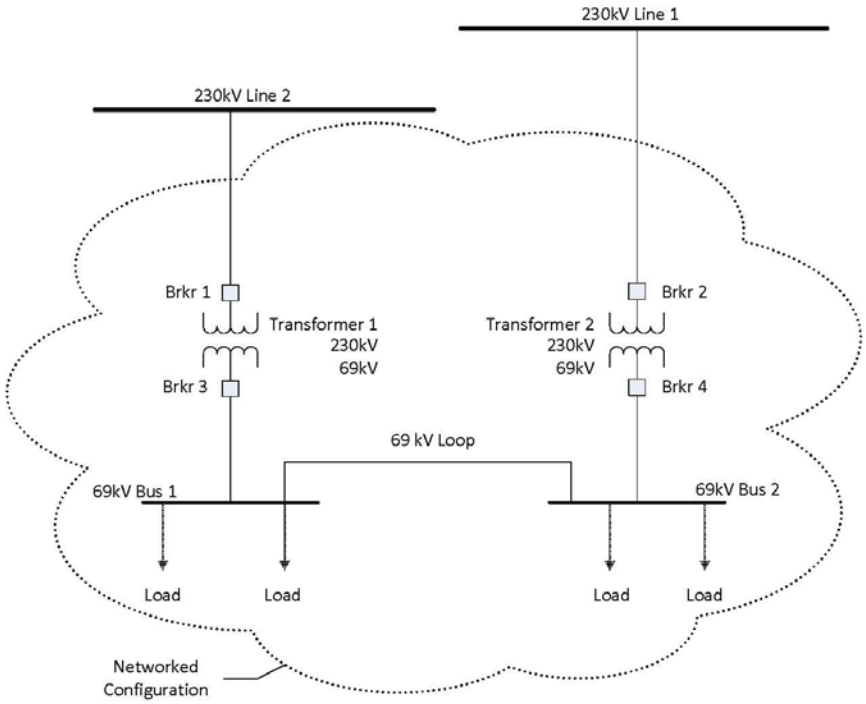
94. We seek further explanation and comment on the statement above that "neither will the local network's separation or retirement diminish the reliability of the interconnected electric transmission network." While a radial facility emanates from one point of connection to the interconnected transmission network, a local network by definition has multiple points of connection to the interconnected transmission network. Thus, regarding a local network, a contingency situation may arise where one of the multiple connections to the interconnected transmission network separates, while other local network connections maintain connectivity with the bulk electric system. We seek comments to better understand how an entity with a candidate local network would analyze such contingencies to determine potential impacts to the reliable operation of the interconnected transmission network.

i. Contiguous Transmission Elements and the 100 kV Lower Limit/300 kV Cap

95. As stated above, exclusion E3 defines local networks as "[a] group of *contiguous* transmission Elements *operated at or above 100 kV but less than 300 kV* that distribute power to Load rather than transfer bulk-power across the interconnected system." While the local network exclusion applies to contiguous transmission elements operating at a minimum of 100 kV, it is unclear how the exclusion applies to a looped lower voltage system. For example, figure 5 depicts a 69 kV looped system emanating from two points of connection at 100 kV or higher.

Figure 5

Networked Configuration w/69 kV Loop



The configuration in figure 5 depicts a group of elements that are contiguous through a 69 kV loop. We seek comment whether the configuration in figure 5 qualifies as a local network and, in particular, whether the configuration satisfies the condition that a local network consists of "a group of *contiguous* transmission Elements *operated at or above 100 kV*…."

96. NERC states the selection of a 300 kV cap for the applicability of an exclusion for a local network was based upon recent NERC standards development work in Project 2006-02 "Assess Transmission Future Needs and Develop Transmission Plans" which sets a voltage level of 300 kV to differentiate extra high voltage (EHV) facilities from high voltage facilities acting as a threshold to distinguish between expected system

performance criteria.[110] NERC states that it seeks to establish consistency in the limitations placed on the exclusion applicability for local network facilities, and has therefore adopted this 300 kV level to ensure that EHV facilities are not subject to this exclusion.[111] NERC provides a "realistic example of the electrical interaction between a typical local network and the [bulk electric system]" in the LN Technical Paper.[112] The example depicted in Appendix 1 of the Technical Paper shows a local network operating at 115 kV. The NERC Technical Paper does not provide examples of a local network operating within the 200 to 300 kV range, for example showing 230 kV facilities operating in a local network. We are concerned whether the 300 kV ceiling is appropriate and reflects actual system configurations that serve local distribution, the stated purpose of the local network exclusion.[113] Accordingly, we seek comment whether (and why or why not) the 300 kV ceiling is appropriate for the application of exclusion E3 and requests examples of systems between 200 and 300 kV that would qualify for this exclusion.[114]

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[110] NERC BES Petition at 23.

[111] *Id.* at 23 and Exh. G at 4.

[112] *Id.,* Exh. G at 5.

[113] The Commission notes additional differentiations may directly address this concern, such as applying a load limit, which was raised by the NERC System Analysis and Modeling Subcommittee (SAMS) in its effort to support Phase 2 of the bulk electric system definition project as a criterion to limit the exclusion of large cities and regions.

[114] To the extent the information requested is confidential, commenters may provide the information pursuant to 18 C.F.R § 388.112 of the Commission's regulations.

ii. Criterion (a) – Limits on Connected Generation

97. Exclusion E3 criterion (a) provides that the local network and its underlying elements do not include the blackstart resources identified in inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA gross nameplate rating. In addition, criterion (a) does not limit the amount of generation besides "non-retail generation" connected to the local network. The Commission agrees with NERC that "local networks" do not include blackstart resources and agrees with the limits on the connected generation imposed by this exclusion.

iii. Criterion (b) – Power Flows only into the Local Network

98. Exclusion E3 criterion (b) specifies that to be eligible for the exclusion, power can only flow into the local network and the local network does not transfer energy originating outside the local network for delivery through the local network. Thus, it appears that, pursuant to criterion (b), generation produced inside a local network is not transporting power to other markets outside the local network. The Commission understands that criterion (b) applies in both normal and emergency operating conditions.[115]

[115] *See* NERC BES Petition, Exh. E at 59 ("The Commission directed NERC to revise its BES definition to ensure that the definition encompasses all Facilities necessary for operating an interconnected electric Transmission network. The SDT interprets this to include operation under both normal and Emergency conditions….").

iv. Criterion (c) – Not Part of a Flowgate or Transfer Path

99. Exclusion E3 criterion (c) specifies a "local network" does not contain a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an interconnection reliability operating limit. The Commission believes that this is an appropriate criterion.

d. Exclusion E4 (Reactive Power Devices)

100. Exclusion E4 excludes from the bulk electric system "Reactive Power devices owned and operated by the retail customer solely for its own use." NERC explains that exclusion E4 is the technical equivalent of Exclusion E2 for reactive power devices and that the currently effective bulk electric system definition is unclear as to how these devices are to be treated. We believe that this is an appropriate exclusion that provides additional clarity and granularity to the definition of bulk electric system.

Summary

101. In sum, we propose to approve NERC's revised definition of the term bulk electric system, including the specific inclusions and exclusions. We believe that NERC's proposal provides a reasonable basis for the identification of bulk electric system elements and appears to improve upon the currently effective definition by: (1) removing the language that provides for regional discretion, (2) removing the language "generally operated at…" so as to create a clear 100 kV threshold; and (3) providing additional clarity and granularity. Above, we have asked for comment on a series of questions

regarding the applicability of the "core" definition and specific inclusions and exclusions. We believe that comments on these questions will assist in providing further clarity and understanding of the NERC proposal. We further note that although we propose to approve the definition in this rulemaking, the responses to our questions are intended to guide the Commission as to whether other action is necessary, for example, by directing NERC to develop a further modification to the definition or inclusions/exclusions pursuant to section 215(d)(5) of the FPA.

C. The Commission Proposes to Approve the NERC Rules of Procedure that Provide a Case-Specific Exception Process

102. As described above, in Docket No. RM12-7-000, NERC submitted proposed revisions to its Rules of Procedure that provide procedures for requesting and receiving case-specific exception from the definition of bulk electric system.[116]

103. Pursuant to FPA section 215(f), we propose to find that the exception process is just, reasonable, not unduly discriminatory or preferential, and in the public interest and satisfies the requirements of section 215(c). Further, we believe that the proposal satisfies the statement in Order No. 743 that NERC establish an exception process for excluding facilities that are not necessary for the reliable operation of the interconnected transmission network from the definition of the bulk electric system.[117]

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[116] *See* Section I.D.2 above for further description of NERC's proposed revisions to the NERC Rules of Procedure.

[117] *See* Order No. 743, 133 FERC ¶ 61,150 at P 16.

104. NERC explains that it was not feasible to develop a single set of technical criteria that would be applicable to all exception requests so it developed the Detailed Information Form to ensure that a consistent baseline of technical information is provided for NERC to make a decision on all exception requests. This information and the proposed exception process allows NERC to provide consistent determinations on exception requests submitted from different regions involving the same or similar facts and circumstances, and allows NERC to take into account the aggregate impact on the bulk electric system of approving or denying all the exception requests. Finally, the exception process includes provisions for reporting information that may alter the status of an approved exception, verifying whether an exception continues to be warranted, and revoking an exception that is no longer warranted.[118] Thus, we believe that this process is equally efficient and effective as the Order No. 743 directive to establish an exception process for excluding facilities that are not necessary for the reliable operation of the interconnected transmission network. In addition, we believe that NERC's proposal appears to be clear, transparent, and uniformly applicable..

105. NERC and the industry should be commended for the development of the 100 kV threshold, the identified inclusions and exclusions, and the exception process. Together, this package of important reforms will bring valuable improvements to the process of identifying those facilities that are necessary for the operation of the interconnected

[118] NERC ROP Petition at 16.

transmission network, and thus should be included in the definition of bulk electric system. For these reasons, we propose to approve NERC's proposals, as discussed above.

106. The Commission seeks input from NERC and the industry, however, as to additional reforms that may be needed to the definition or to the Rules of Procedure to ensure that, over the long term, the facilities necessary to the reliability of the interconnected transmission network are captured in its definition. In particular, we note that while establishing a "bright-line" threshold of 100 kV has significant advantages, it may not capture all facilities that are necessary for the operation of the interconnected transmission network that fall below that threshold. As the Commission indicated in Order No. 743 and Order No. 743-A, its goal is that the definition of bulk electric system should include all facilities necessary for the operation of the interconnected transmission network, except for local distribution. Although the Commission indicated that one way to meet this goal was to establish a 100 kV "bright-line" threshold, the Commission also made clear that the "bright-line" threshold would be a "first step or proxy" in determining which facilities should be included in the bulk electric system.[119] Indeed, the Commission, agreeing with commenters, held that NERC should not necessarily stop at 100 kV and should, through the development of the exception process, ensure that "critical" facilities operated at less than 100 kV, and that the Regional Entities determine

[119] Order No. 743-A, 134 FERC ¶ 61,210 at P 40.

are necessary for operating the interconnection network.[120] The Commission clarified that including sub-100 kV facilities should be done in an "appropriate and consistent" manner.[121]

107. Recent events reinforce the Commission's statements in Order Nos. 743 and 743-A with respect to ensuring that sub-100 kV facilities, as appropriate, are included in the bulk electric system. The September 2011 Blackout Report concluded that certain sub-100 kV facilities, which were not designated as bulk electric system facilities, contributed to the cascading blackout affecting San Diego, California.[122] The September 2011 Blackout Report makes clear that, while certain sub-100 kV facilities can affect bulk electric system reliability, entities may not study or communicate their impacts and take appropriate action unless they are properly designated as part of the bulk electric system.[123] Thus, the September 2011 Blackout Report recommended that "WECC, as the [Regional Entity], should lead other entities, including [transmission operators] and [balancing authorities], to ensure that all facilities that can adversely impact [Bulk-Power System] reliability are either designated as part of the [bulk electric system] or otherwise incorporated into planning and operations studies and actively monitored and alarmed in

[120] Order No. 743, 133 FERC ¶ 61,150 at P 121.

[121] Order No. 743-A, 134 FERC ¶ 61,210 at P 103.

[122] *See* September 2011 Blackout Report at 96-97.

[123] *Id.* at 7-8.

[real-time contingency analysis] systems."[124] Although the Blackout Report addressed an event in WECC, the recommendations in the Blackout Report should not be limited only to the Western interconnection. Indeed, as explained above, the recommendation in the September 2011 Blackout Report that sub-100 kV facilities be reviewed for inclusion in the bulk electric system is consistent with the Commission's findings in Order Nos. 743 and 743-A.

108. The NERC proposals at issue in this NOPR take steps to address the treatment of sub-100 kV facilities, as well as other facilities, necessary for the operation of the interconnected transmission network, through the exception process, which provides an avenue for Regional Entities, planning authorities, reliability coordinators, transmission operators, transmission planners, balancing authorities, and owners of system elements to submit a request to include a facility in the bulk electric system. We believe that regional entities, reliability coordinators, transmission owners, transmission operators, balancing authorities and other registered entities need to evaluate their sub-100 kV facilities, as well as other facilities, that are necessary to operate the interconnected transmission network in an "appropriate and consistent" manner to determine their potential impacts on bulk electric system reliability and, based on that review, seek to include those facilities in the bulk electric system through this proposed exception process.[125] These

[124] *Id.* at 96, Recommendation 17.

[125] NERC's performance of a final review of exception requests under the Rules of Procedure should ensure national consistency under that procedure.

entities have the in-depth, "on the ground" knowledge and expertise of what facilities are critical to reliable operations in their local or regional area. As a result, we believe they bear primary responsibility to analyze the elements within their purview to ensure that the right facilities are included in the bulk electric system. We seek comment on how the relevant entities will conduct the review and seek inclusion of facilities.

109. The Commission expects that these entities will use the exception process as contemplated to include sub-100 kV facilities, and other facilities, necessary for the operation of the interconnected transmission network in the bulk electric system. Nonetheless, we note that relying on these entities alone may, in certain limited circumstances, have the potential to leave out sub-100 kV facilities necessary for the operation of the interconnected transmission network. For example, NERC or the Commission may, in the performance of their statutory functions and general oversight of reliability matters, discover additional sub-100 kV facilities that should be included. The joint NERC-FERC September 2011 Blackout Report, as noted above, is a prime example of this possibility. In addition, while we recognize that the owners and operators of the power grid take their reliability obligations seriously, there may be instances when not all of the facilities necessary for the operation of the interconnected transmission network are included in the bulk electric system.

110. Thus, while we propose to approve the package of reforms submitted by NERC, we seek comment on how the relevant entities will seek inclusion of sub-100 kV elements to ensure that all facilities that are necessary for the operation of the bulk power system are designated as bulk electric system elements consistent with the discussion

above. These comments also should aid NERC, industry, and the Commission in further efforts, already underway in Phase 2 , to refine the bulk electric system definition, the inclusions and exclusions, and the exception process.

111. In addition to general comments on the discussion above, we seek comments on the role NERC should have in initiating the designation of (or directing others to initiate the designation of) sub-100 kV facilities, or any other facilities, necessary for the operation of the interconnected transmission network for inclusion in the bulk electric system. The exception process as proposed does not provide that NERC may initiate an exception request. Given its statutory functions to develop and enforce Reliability Standards and its continent-wide perspective, NERC has technical understanding that may provide valuable assistance in the identification of bulk electric system facilities and elements. For example, NERC conducts disturbance assessments, oversees compliance monitoring and conducts seasonal assessments, all of which provide information and understanding regarding the operations of the bulk electric system. The Commission seeks comment on the role NERC should have in designating sub-100 kV facilities, and other facilities, for inclusion in the bulk electric system, directing Regional Entities or others to conduct such reviews, or itself nominating an element to be included in the bulk electric system.[126]

[126] Since NERC makes the final determination pursuant to the proposed process, a modified process may need to be created if NERC has a role in submitting requests. For example, a different entity would likely need to make the final determination.

112. We also seek comment on the role the Commission should have with respect to the designation of sub-100 kV facilities, or other facilities, necessary for the operation of the interconnected transmission network for inclusion in the bulk electric system. As noted above, there may be circumstances (like the September 2011 Blackout Report) where the Commission, through the performance of its statutory functions, may conclude that certain sub-100 kV facilities not already included in the bulk electric system are necessary for the operation of the interconnected transmission network and thus should be included in the bulk electric system. While, as noted above, we expect that regional entities and others will take affirmative steps to review and include sub-100 kV elements and facilities, and other facilities, necessary for the operation of the interconnected transmission system in the bulk electric system, we seek comment as to how the Commission, if necessary, could ensure that such facilities are considered for inclusion in the bulk electric system. We also seek comment on instances when the Commission itself should designate (or direct others to designate) sub-100 kV facilities, or other facilities, necessary for the operation of the interconnected transmission grid for inclusion in the bulk electric system.[127]

1. Technical Review Panel

113. NERC's proposed exception process provides that "[t]he Regional Entity shall not recommend Disapproval of the Exception Request in whole or in part without first

[127] The Commission contemplates that, if it were to take such a step, it would provide an opportunity for notice and comment.

submitting the Exception Request for review to a Technical Review Panel and receiving its opinion…"[128] The technical review panel member must have the required technical background, must not have participated in the review of the exception request, and not have a conflict of interest in the matter.[129] The Regional Entity is not bound by the opinion of the panel, but the panel's evaluation becomes part of the record associated with the exception request and provided to NERC.

114. We see value in the Regional Entity receiving the independent opinion of a qualified technical review panel. NERC, however, does not explain why the proposed Rules only require a technical review panel to provide an opinion where the Regional Entity recommends disapproval of an exception request. We seek comment from NERC explaining whether it considered obtaining the opinion of a technical panel for all Regional Entity recommendations and, if so, why the review is only required when a Regional Entity disapproves a request. Further, we seek comment on whether NERC should modify the exception process to require Regional Entities to submit all proposed determinations to a technical review panel regardless of the recommendation and receive the panel's opinion on each request.

[128] NERC ROP Petition, Att. 1, Proposed App. 5C to the Rules of Procedure, section 5.2.4.

[129] *Id.* at App. 5C, section 5.3.

2. Use of Industry Subject Matter Experts

115. Section 8 of the proposed exception process sets forth the procedures for NERC's review of a Regional Entity's recommendation. The NERC President will appoint a team of at least three persons with the technical background to evaluate an exception request. The members of the review team must have no financial, contractual, employment or other interest in the submitting entity or owner that would present a conflict of interest and must be free of any conflicts of interest in accordance with NERC policies.[130] NERC states that "at the present time NERC anticipates that its review teams would be drawn from NERC staff resources, supplemented by contractors as necessary particularly where needed to provide specific relevant subject matter expertise. However, situations may arise in which NERC may need to call on industry subject matter experts to participate as members of review teams."[131]

116. We support NERC's proposal to use staff resources, supplemented by contractors as necessary, to make up the exception request review teams. We believe that consistent appointment of the same NERC staff and contractor resources, based on subject matter expertise, will promote a more uniform and consistent review of the Regional Entities' exception request recommendations.

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[130] NERC ROP Petition at 31.

[131] *Id.* at n. 29.

D. The Commission Proposes to Approve NERC's Detailed Information Form

117. As described above, NERC developed the Detailed Information Form that the Regional Entity and NERC can use in evaluating whether or not the elements that are the subject of an exception request are necessary for operating the interconnected transmission network. The Detailed Information Form encompasses a wide range of potential configurations and appears to ensure that a consistent baseline of technical information is provided with all exception requests, in addition to the specific information and arguments provided by the submitting entity in support of its exception request. The information that the applicant may submit in support of an exception request will not be limited to the Detailed Information Form. The applicant will be expected to submit all relevant data, studies and other information that supports its exception request. Further, NERC may ask the submitting entity to provide other data, studies and information in addition to the Detailed Information Form and the other information included by the applicant in the exception request.

118. We believe that this information will provide consistency with respect to the technical information provided with all exception requests and is an equally efficient and effective approach to developing a substantive set of technical criteria for granting and rejecting exception requests. Accordingly, we propose to approve the Detailed Information Form included in NERC's filing.

E. The Commission Proposes to Approve NERC's Implementation Plan for the Revised Definition of Bulk Electric System

119. As noted above, NERC requests that the revised definition "should be effective on the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, the revised [bulk electric system definition] should go into effect on the first day of the second calendar quarter after its adoption by the NERC Board.[132]

120. NERC also requests that compliance obligations for all elements newly-identified to be included in the bulk electric system based on the revised definition should begin twenty-four months after the applicable effective date of the revised definition. While the Commission stated in Order Nos. 743 and 743-A that the transition period should not exceed 18 months from the date of Commission approval of the revised definition, the Commission also stated that it could approve a longer transition period based on specific justification.[133] NERC states that sufficient time is needed: (1) to implement transition plans in order to accommodate any changes resulting from the revised definition; (2) for entities to file for exceptions, and for the Regional Entities and NERC to process those exceptions to a final determination, pursuant to the proposed exception process; and (3) for owners of facilities and elements that are newly-included in the bulk electric system based on the definition to train their personnel on compliance with the Reliability

[132] NERC BES Petition at 34.

[133] Order No. 743, 133 FERC ¶ 61,150 at P 131.

Standards applicable to the newly-included facilities and elements, so that these entities can achieve compliance with applicable Reliability Standards by the end of the transition period. We believe that NERC has provided adequate justification for its implementation plan, as discussed above. Thus, although NERC's plan exceeds the 18 month implementation period set forth in Order No. 743, we propose to approve NERC's implementation plan.

F. NERC List of Facilities Granted Exceptions

121. In Order No. 743, the Commission stated that "a Commission staff audit would review the application of the exemption criteria developed by NERC in NERC's or a Regional Entity's determination to approve an exemption for a particular facility." The Commission also stated that "to facilitate such audits, the ERO should maintain a list of exempted facilities that can be made available to the Commission on request. NERC can decide how best to maintain the list, including determining whether or not to post it on the NERC website."[134]

122. NERC states that the proposed exception process does not include provisions for NERC to maintain a list of facilities that have received exceptions, as this is an internal administrative matter for NERC to implement that does not need to be embedded in NERC Rules of Procedure. [135] NERC states it will develop a specific internal plan and

[134] *Id.* PP 117, 119.

[135] NERC ROP Petition at 49.

procedures for maintaining a list of facilities for which exceptions have been granted. Further, NERC explains that it has not yet determined how the list will be organized and structured and under what conditions the list will be made available on the NERC web site or otherwise made available to any entities other than the Commission, citing concerns about confidential information and critical energy infrastructure information.[136]

123. We understand that NERC is continuing to develop the details on how it will maintain the list of facilities that have received exceptions. However, we also consider the maintenance of this list of facilities an important feature for tracking exceptions.[137] Thus, we propose that NERC file an informational filing within 90 days of the effective date of a final rule, detailing its plans to maintain a list and how it will make this information available to the Commission, Regional Entities, and potentially to other interested persons. We seek comment from NERC whether this deadline provides adequate time for NERC to finalize its plans and submit an informational filing.

124. While NERC states that it will maintain a list of facilities that have received an exception pursuant to the case-specific exception process, the petition does not indicate whether NERC will track an entity's "declassification" of current bulk electric system facilities based on the entity's self-application of the bulk electric system definition. It appears that, in some circumstances, the appropriate Regional Entity would receive a

[136] *Id*.

[137] Order No. 743, 133 FERC ¶ 61,150 at PP 117, 119.

request that an entity be removed from the NERC Compliance Registry. For example, if an entity determines that its entire system satisfies the exclusion E1 for radial systems, the entity could apply to the appropriate Regional Entity to be removed from the NERC Compliance Registry. However, in other circumstances, it is not clear what, if any, notification an entity would provide to NERC or a Regional Entity when the entity self-determines that an element is no longer part of the bulk electric system. For example, a large utility with hundreds or thousands of transmission lines may initially determine that a configuration on its system does not qualify for the exclusion E3 local network exclusion, but subsequently determines that the configuration can be excluded. NERC's petition does not indicate whether an entity in such circumstance is obligated to inform NERC or the appropriate Regional Entity of that self-determination. It appears that NERC and the Regional Entities would need this information for their compliance programs, for audit purposes, and to understand the contours of the bulk electric system within a particular region. Accordingly, we seek comment on whether NERC's proposal should be modified to include an obligation for the registered entity to inform NERC or the Regional Entity of the entity's self-determination through application of the definition and specific exclusions E1 through E4 that an element is no longer part of the bulk electric system.

III. Information Collection Statement

125. The following collection of information contained in this Proposed Rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[138] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[139] The Commission solicits comment on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically the Commission asks that any revised burden estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated.

126. In Order No. 693, the Commission approved NERC's definition of the term bulk electric system and the associated information requirements.

127. In Order No. 743, the Commission directed NERC to develop a revised "bulk electric system" definition. The Commission explained that, by directing NERC to develop a revised definition, "the Commission is maintaining the status quo (i.e., the current bulk electric system definition) until the Commission approves a revised

[138] 44 U.S.C. § 3507(d) (2006).

[139] 5 C.F.R. § 1320.11 (2011).

definition. Thus, the Commission's action does not add to or increase entities' reporting burden."[140]

128. The immediate NOPR proposes to approve the revision to the definition of "bulk electric system" developed by NERC and an exception process to include or exclude specific elements in the definition of "bulk electric system" on a case-by-case basis. The Commission is basing its burden estimate below on the revised definition of "bulk electric system" developed by NERC.

129. The proposal in this NOPR would result in entities reviewing systems and creating qualified asset lists, submitting exception requests where appropriate, and certain responsible entities having to comply with requirements to collect and maintain information in mandatory Reliability Standards with respect to certain facilities for the first time.

130. Public Reporting Burden: While the Commission requests comment concerning the information collections proposed in this NOPR and the associated burden estimates, in particular, the Commission requests comment on the following issues.

131. First, we request comment on the estimated number of entities that will have an increased reporting burden associated with the identification of new bulk electric system elements as a result of the modified definition. NERC states in its filing that "[i]t was not the intent nor the expectation of either the [standard drafting team] or NERC to either

[140] Order No. 743, 133 FERC ¶ 61,150 at P 157.

expand or reduce the scope of the [bulk electric system], or (with the likely exception of the NPCC Region) to increase or decrease the number of Elements included in the [bulk electric system], through the revised [bulk electric system] definition as compared to the current [bulk electric system] definition."[141] NERC adds that it has no specific basis to determine to "the extent Elements currently included in the [bulk electric system] will become not included, nor to what extent Elements currently not included will become included."[142] In developing an estimate of the reporting burden associated with the inclusion of additional elements, like NERC, we assume that entities in the NPCC Region will be most affected, with a lesser affect in other regions.[143]

132. We reviewed Compliance registry information for the NPCC Region to determine the number and types of registered entities in the U.S. portion of the NPCC Region.[144] We expect that transmission owners and distribution providers, and some generator owners, are most likely to identify new elements. Based on this, we estimate a range from 66 to 155 affected entities in the NPCC region, and for OMB reporting purposes identify below a median number of 111 affected entities in the NPCC region. Further,

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[141] NERC BES Petition at 37.

[142] *Id.*

[143] While Reliability Standards do not require the reporting of information directly to the Commission, the application of Reliability Standards to additional facilities will have associated information collection and retention obligations.

[144] NPCC Compliance Registry information is available on the NPCC website at: https://www.npcc.org/Compliance/Default.aspx.

consistent with NERC's explanation, we do not expect a significant number of registered entities outside of the NPCC region to identify new elements under the revised bulk electric system definition. Accordingly, we estimate a total of 75 entities outside of the NPCC Region having new "implementation plan and compliance" related reporting burdens. We seek comment on these estimates to assist the Commission in arriving at final estimates.

133. Second, we seek comment on the reporting burden associated with exception requests. NERC indicates that "there is currently not a basis for estimating the numbers of Exceptions Requests that will be submitted…."[145] We agree with NERC that there is difficulty in estimating a specific number of exception requests as this is a new process with no "track record." Thus, rather than estimating a specific number of exception requests, we estimate a range of exception requests that may be submitted. As indicated in the table below, from the 1,730 total transmission owners, generator owners and distribution providers in the Compliance Registry, we estimate a range of 87 to 433 exception requests per year for each of the first two years after the effective date of a final rule. We request comment on this estimated range to assist the Commission in arriving at a final estimate of the number of possible exception requests.

134. Third, as indicated above, our estimates are based in part on an expectation that transmission owners, generator owners and distribution providers will experience more

[145] NERC BES Petition at 38.

significant reporting burdens than other categories of registered entities. We seek comment on this expectation, and whether and to what extent other categories of registered entities (in addition to transmission owners, generator owners and distribution providers) may have a public reporting burden.

135. We estimate that the increased Public Reporting Burden for this Proposed Rule is as follows:

Requirement	Number and Type of Entity[146] (1)	Number of Responses Per Entity (2)	Average Number of Hours per Response (3)	Total Burden Hours (1)*(2)*(3)
System Review and List Creation[147]	333 Transmission Owners	1 response	80 (engineer hours)	26,640 Yr 1
	843 Generator Owners		16 (engineer hours)	13,488 Yr 1
	554 Distribution Providers		24 (engineer hours)	13,296 Yr 1

[146] The "entities" listed in this table are describing a role a company is registered for in the NERC registry. For example, a single company may be registered as a transmission owner and generator owner. The total number of companies applicable to this rule is 1,522, based on the NERC registry. The total number of estimated roles is 1,730.

[147] This requirement corresponds to Step 1 of NERC's proposed transition plan, which requires each U.S. asset owner to apply the revised bulk electric system definition to all elements to determine if those elements are included in the bulk electric system pursuant to the revised definition. *See* NERC BES Petition at 38.

Exception Requests[148]	1,730 total Transmission Owners, Generator Owners and Distribution Providers	.15 responses in Yrs 1 and 2	94 (60 engineer hrs, 32 record keeping hrs, 2 legal hrs)	24,393 hrs in Yrs 1 and 2
		0.01156 responses in Yr 3 and ongoing		1,880 hrs in Yr 3 and ongoing
Regional and ERO Handling of Exception Requests[149]	NERC and 8 Regional Entities	1 response	1,386.67 hrs	12,480 hrs in Yrs 1 and 2
Implementation Plans and Compliance[150]	111 NPCC Region Registered Entities[151]	1 response	700 hrs in Yrs 1 and 2	77,700 hrs in Yrs 1 and 2
			350 hrs in Yr 3 and ongoing	38,850 hrs in Yr 3 and ongoing
	75 Registered Entities from	1 response	700 hrs in Yrs 1 and 2	52,500 hrs in Yrs 1 and 2

[148] We recognize that not all 1,730 transmission owners, generator owners and distribution providers will submit an exception request. Rather, from the total 1,730 entities, we estimate an average of 260 requests per year in the first two years, based on a low to high range of 87 to 433 requests per year. Therefore, the estimated total number of hours per year for years 1 and 2, using an average of 260 requests per year, is 24,393 hours. We estimate 20 requests per year in year 3 and ongoing.

[149] Based on the assumption of two full-time equivalent employees added to NERC staff and 0.5 full-time equivalent employees added to each region's staff, each full-time equivalent at $120,000/year (salary + benefits).

[150] The Commission does not expect a significant number of registered entities outside of the NPCC region to identify new elements under the revised bulk electric system definition. NERC also states that the other Regional Entities do not expect an extensive amount of newly-included facilities. *See* NERC BES Petition at 38. "Compliance" refers to entities with new elements under the new bulk electric system definition required to comply with the data collection and retention requirements in certain Reliability Standards that they did not previously have to comply with.

[151] The estimated range of affected NPCC Region Registered Entities is from 66 to 155 entities.

	7 other Regions		350 hrs in Yr 3 and ongoing	26,250 hrs in Yr 3 and ongoing
TOTALS				220,497 hrs in Yr 1
				167,073 hrs in Yr 2
				66,980 hrs in Yr 3 and ongoing

Information Collection Costs: The Commission seeks comment on the costs to comply with these requirements. These cost estimates are calculated using the average of the ranges suggested in the burden hour estimates. It has projected the annual cost to be:

- Year 1: **$13,641,200**
- Year 2: **$10,435,760**
- Year 3 and ongoing: **$4,343,520**.

For the first two burden categories above, the loaded (salary plus benefits) costs are: $60/hour for an engineer; $27/hour for recordkeeping; and $106/hour for legal. The breakdown of cost by item and year follows:

- **System Review and List Creation (year 1 only)**: (26,640 hrs + 13,488 hrs + 13,296 hrs) =53,424 hrs * 60/hr = $3,205,440.
- **Exception Requests (years 1 and 2)**: (sum of hourly expense per request * number of exception requests) = ((60 hrs * $60/hr) + (32 hrs * $27/hr) + (2hrs * $106/hr)) * 260 requests) = $1,215,760.

- **Exception Requests (year 3)**: (sum of hourly expense per request * number of exception requests) = ((60 hrs * $60/hr) + (32 hrs * $27/hr) + (2 hrs * $106/hr)) * 20 requests) = $93,520.
- **Regional and ERO handling of Exception Requests**: Between NERC and regional entities we estimate 6 full time equivalent (FTE) engineers will be added at an annual cost of $120,000/FTE ($120,000/FTE * 6 FTE = $720,000). This cost is only expected in years 1 and 2.
- **Implementation Plans and Compliance[152] (years 1 and 2)**: (hourly expense per entity * hours per response * sum of NPCC and non-NPCC entities) = ($64/hour * 700 hours per response * 186 responses) = $8,332,800.
- **Implementation Plans and Compliance (year 3 and beyond):** We estimate the ongoing cost for year 3 and beyond, at 50% of the year 1 and 2 costs, to be $4,166,400.

Title: FERC-725-J "Definition of the Bulk Electric System"[153]

[152] The cost and hourly burden calculations for this category are based on a past assessment (NPCC Assessment of Bulk Electric System Definition, September 14, 2009.). In that assessment NPCC indicated $8.9 million annually for operations, maintenance and additional costs. We estimated that roughly half of that cost actually relates to information collection burden. Using the resulting figure, we used a composite wage and benefit figure of $64/hour to estimate the hourly burden figures presented in the burden table.

[153] All of the information collection requirements for years 1-3 in the proposed rule are being accounted for under the new collection FERC-725J.

Action: Proposed Collection of Information

OMB Control No: To be determined

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: On Occasion

Necessity of the Information: The proposed revision to NERC's definition of the term bulk electric system, if adopted, would implement the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the proposal would ensure that certain facilities needed for the operation of the nation's bulk electric system are subject to mandatory and enforceable Reliability Standards.

Internal review: The Commission has reviewed the proposed definition and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimate associated with the information requirements.

136. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

137. Comments concerning the information collections proposed in this NOPR and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory

Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference FERC-725J and the docket numbers of this Proposed Rulemaking (Docket Nos. RM12-6-000 and RM12-7-000) in your submission.

IV. Regulatory Flexibility Act Analysis

138. The Regulatory Flexibility Act of 1980 (RFA)[154] generally requires a description and analysis of Proposed Rules that will have a significant economic impact on a substantial number of small entities. As discussed above, the Commission believes that the immediate effect of the proposal to approve the modification to the definition of bulk electric system and the exception process would likely be limited to certain transmission owners, generator owners and distribution service providers, as well as NERC and Regional Entities. Many transmission owners, generator owners and distribution service providers do not fall within the definition of small entities.[155] The Commission estimates

[154] 5 U.S.C. §§ 601-612 (2006).

[155] The RFA definition of "small entity" refers to the definition provided in the Small Business Act (SBA), which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. *See* 15 U.S.C. § 632 (2006). According to the SBA, an electric utility is defined as "small" if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

that approximately 418[156] of the 1,730 registered transmission owners, generator owners and distribution service providers may fall within the definition of small entities.[157]

139. The Commission estimates that of the 418 small entities affected there are 50 within the NPCC region that would have to comply with the Proposed Rule. The Commission assumes that the Proposed Rule would affect more small entities in the NPCC Region than those outside NPCC as it is assumed that there are more elements in NPCC that would be added to the bulk electric system based on the new definition than elsewhere. The Commission estimates the first year affect on small entities within the NPCC region to be $39,414.[158] This figure is based on information collection costs plus

[156] We note that in Order No. 693, the Commission estimated that the Reliability Standards in that the Final Rule would apply to approximately 682 small entities. *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1940. Because the current Proposed Rule would affect a smaller subset of the categories of registered entities, our estimate is lower than that cited in Order No. 693.

[157] The number of small entities is generated by comparing the NERC compliance registry with data submitted to the Energy Information Administration on Form EIA–861. Note, these numbers do not account for companies that may be registered in more than one role. For companies registered in more than one role, the burden will likely be higher than for those companies registered in only one role. We estimate that there are 381 companies and 418 registered roles, meaning that several companies are registered in more than one role. We do not believe this affects the certification below.

[158] For companies registered as more than one entity in the NERC compliance registry this figure will increase accordingly. That is, if a company is registered as a transmission owner and generator owner then the cost burden would be $78,828 ($39,414*2 = $78,828).

additional costs for compliance.[159] The Commission estimates the average annual affect per small entity outside of NPCC will be less than for the entities within NPCC. The Commission does not consider this to be a significant economic impact for either class of entities because it should not represent a significant percentage of the operating budget. Accordingly, the Commission certifies that this Proposed Rule will not have a significant economic impact on a substantial number of small entities. The Commission seeks comment on this certification.

V. Environmental Analysis

140. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[160] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for

[159] We use fifty percent of the first year "number of hours per response" figure in the information collection statement for calculation under the assumption that smaller entities do not have complicated systems or will not have as many new elements on average as larger entities do.

[160] Order No. 486, *Regulations Implementing the National Environmental Policy Act*, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986-1990 ¶ 30,783 (1987).

information gathering, analysis, and dissemination.[161] Accordingly, neither an environmental impact statement nor environmental assessment is required.

VI. Comment Procedures

141. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [INSERT DATE 60 days after publication in the **FEDERAL REGISTER**]. Comments must refer to Docket Nos. RM12-6-000 and RM12-7-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

142. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

143. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC, 20426.

[161] 18 C.F.R. § 380.4(a)(5).

144. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

145. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

146. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

147. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of subjects in 18 CFR Part 40

By direction of the Commission. Commissioner Clark voting present.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

June 21, 2012

Chairman Jon Wellinghoff

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. RM12-6-000 and RM12-7-000

Item No. E-4

Statement of Chairman Jon Wellinghoff on NERC's Revised Definition for Bulk Electric System

"Today's order represents another step in the refinement of the definition of the Bulk Electric System. Since we first relied on NERC's initial definition in Order No. 693, and again in directing NERC to refine the definition in Order No. 743, the Commission has continued to work with NERC to establish a definition that provides certainty to industry, yet is flexible enough to exclude facilities that are not necessary for reliably operating the grid.

In today's order, we propose to approve NERC's bright-line threshold of 100 kV or higher and specific configurations to be included and excluded in the definition of the Bulk Electric System, as well as NERC's proposed exception procedure to add and remove elements from the definition. I look forward to reviewing the comments on this NOPR, and in continuing to work with NERC to refine the definition so that the Commission and NERC can focus on those facilities which ensure the reliability of the grid."

Proposed Rule

Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure

A Proposed Rule by the Federal Energy Regulatory Commission on 07/05/2012

This article has a comment period that ends in 60 days (09/04/2012)

SUBMIT A FORMAL COMMENT

ACTION Notice Of Proposed Rulemaking.

SUMMARY Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to approve a modification to the currently-effective definition of "bulk electric system" developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The revised definition of "bulk electric system" removes language allowing for regional discretion in the currently-effective bulk electric system definition. The revised definition establishes a bright-line threshold that includes all facilities operated at or above 100 kV. The modified definition also identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of "bulk electric system."

The Commission also proposes to approve: (1) NERC's contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, or remove elements from, the definition of "bulk electric system" on a case-by-case basis; (2) NERC's proposed form entitled "Detailed Information To Support an Exception Request" that entities will use to support requests for exception from the "bulk electric system" definition; and (3) NERC's proposed implementation plan for the revised "bulk electric system" definition.

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Docket Number
FERC-2012-1123

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Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure

Public Comments
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Comments are due September 4, 2012.

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Comments, identified by docket number, may be filed in the following ways:

- *Electronic Filing:* Through *http://www.ferc.gov*. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

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Susan Morris (Technical Information),Office of Electric Reliability, Division of Reliability Standards,Federal Energy Regulatory Commission,888 First Street NE.,Washington, DC 20426,Telephone: (202) 502-6803;

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William Edwards (Legal Information),Office of the General Counsel,Federal Energy Regulatory Commission,888 First Street NE.,Washington, DC 20426,Telephone: (202) 502-6669.

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139 FERC ¶ 61,247 Issued June 22, 2012.

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1. Under section 215 of the Federal Power Act (FPA), [1] the Federal Energy Regulatory Commission (Commission) proposes to approve a modification to the currently-effective definition of "bulk electric system" contained in NERC's *Glossary of Terms Used in Reliability Standards* (NERC Glossary) developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. NERC submitted its petition in response to the Commission's directive in Order No. 743 that NERC develop a revised definition of "bulk electric system" using NERC's Reliability Standards development process. [2] The revised definition of bulk electric system:

(a) Removes the basis for regional discretion in the current bulk electric system definition;

(b) Establishes a bright-line threshold so that the "bulk electric system" will be facilities operated at 100 kV or higher, if they are Transmission Elements, or connected at 100 kV or higher, if they are Real Power or Reactive Power resources; and

(c) Contains specific inclusions (I1-I5) and exclusions (E1-E4) to provide clarity in the definition that the facilities described in these configurations are included in or excluded from the "bulk electric system."

2. The Commission also proposes to approve:

(a) NERC's contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, and remove elements from the definition of "bulk electric system" on a case-by-case basis;

(b) NERC's proposed form entitled "Detailed Information to Support an Exception Request" that entities will use to support requests for exceptions from the "bulk electric system" definition; and

(c) NERC's proposed implementation plan for the revised "bulk electric system" definition.

3. NERC's proposed revision to the definition of "bulk electric system" removes regional discretion and establishes a 100 kV bright-line threshold. Further, we believe that NERC's proposal offers additional clarity to the definition of bulk electric system by creating specific inclusions and exclusions within the definition, which provide granularity with regard to common types of facilities and facility configurations and whether they are part of the bulk electric system.

4. We believe that the proposed "core" definition, including the inclusions and the exclusions, as well as the exception process should produce consistency in identifying bulk electric system elements across the reliability regions. In addition, it appears that NERC's proposed exception process to add elements to, and remove elements from, the definition of the bulk electric system adds transparency and uniformity to the process.

5. Although it is rare that the Commission would address Rules of Procedure changes in a rulemaking docket, we will do so in this instance because of the interplay between NERC's modified bulk electric system definition and the newly developed case-specific exception process set forth in NERC's proposed Rules of Procedure change. While we propose to approve NERC's petitions, we also seek comment from NERC and interested parties on certain aspects of NERC's petitions to understand the application of the proposed "core" definition, including the application of the inclusions and exclusions, and the proposed exception process to ensure consistent implementation.

I. Background

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A. Section 215 of the FPA

6. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently. [3] The Commission established a process to select and certify an ERO [4] and, subsequently, certified NERC as the ERO. [5]

B. Order No. 693

7. On March 16, 2007, in Order No. 693, pursuant to section 215(d) of the FPA, the Commission approved 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the NERC Glossary, which includes NERC's definition of bulk electric system. [6] That definition provides:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this

definition. [7]

8. In approving NERC's definition of bulk electric system, the Commission stated that "at least for an initial period, the Commission will rely on the NERC definition of bulk electric system and NERC's registration process to provide as much certainty as possible regarding the applicability to and the responsibility of specific entities to comply with the Reliability Standards." [8] The Commission also stated that "[it] remains concerned about the need to address the potential for gaps in coverage of facilities." [9]

C. Order Nos. 743 and 743-A

9. On November 18, 2010, the Commission revisited the definition of "bulk electric system" in Order No. 743, which directed NERC, through NERC's Reliability Standards Development Process, to revise its definition of the term "bulk electric system" to ensure that the definition encompasses all facilities necessary for operating an interconnected transmission network. The Commission also directed NERC to address the Commission's technical and policy concerns. Among the concerns were inconsistency in application of the definition and a lack of oversight and exclusion of facilities from the bulk electric system that are required for the operation of the interconnected transmission network. In Order No. 743, the Commission stated that the best way to address these concerns is to eliminate the Regional Entity discretion to define bulk electric system without NERC or Commission review, maintain a bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and adopt an exemption process and criteria for removing from the bulk electric system facilities that are not necessary for operating the interconnected transmission network. [10] However, Order No. 743 did not require NERC to adopt these recommendations as the sole means to address the Commission's concerns. Instead, the Commission allowed NERC to "propose a different solution that is as effective as, or superior to, the Commission's proposed approach in addressing the Commission's technical and other concerns so as to ensure that all necessary facilities are included within the scope of the definition." [11] The Commission directed NERC to file the revised definition of bulk electric system and its process to exempt facilities from inclusion in the bulk electric system within one year following the effective date of the final rule. [12]

10. In Order No. 743-A the Commission reaffirmed its determinations in Order No. 743. In addition, the Commission

clarified that the issue the Commission directed NERC to rectify was the discretion the Regional Entities have under the current definition to define the bulk electric system in their regions without any oversight from the Commission or NERC. [13] The Commission also clarified that it was not the Commission's intent through its determination regarding "impact-based methodologies" to disrupt the NERC Rules of Procedure or the Statement of Compliance Registry Criteria (Registry Criteria). [14] Nor did the Commission intend to rule out using any form of a material impact test that can be shown to identify facilities needed for reliable operation. [15] The Commission also clarified that the 100 kV threshold was a "first step or proxy" for determining which facilities should be included in the bulk electric system. [16]

11. The Commission further clarified that the statement in Order No. 743, "determining where the line between `transmission' and `local distribution' lies * * * should be part of the exemption process the ERO develops" was intended to grant discretion to NERC, as the entity with technical expertise, to develop criteria to determine how to differentiate between local distribution and transmission facilities in an objective, consistent, and transparent manner. [17] The Commission stated that the "seven factor test" adopted in Order No. 888 could be relevant and possibly is a logical starting point for determining which facilities are local distribution for reliability purposes. [18] However, the Commission left it to NERC in the first instance to determine if and how the seven factor test should be considered in differentiating between local distribution and transmission facilities for purposes of determining whether a facility should be classified as part of the bulk electric system. [19] Order No. 743-A re-emphasized that local distribution facilities are excluded from the definition of Bulk-Power System and, therefore, must be excluded from the definition of bulk electric system. [20]

D. NERC's Petitions

12. On January 25, 2012, NERC submitted two petitions pursuant to the directives in Order No. 743: (1) NERC's proposed revision to the definition of "bulk electric system" which includes provisions to include and exclude facilities from the "core" definition and (2) revisions to NERC's Rules of Procedure to add a procedure creating an exception process to classify or de-classify a facility as part of the "bulk electric system." In this NOPR, we address both petitions. [21]

1. Revised Definition of Bulk Electric System

13. In Docket No. RM12-06-000, NERC filed a petition requesting Commission approval of a revised definition of "bulk electric system" in the NERC Glossary (NERC BES Petition). As explained below, the definition consists of a "core" definition and a list of facilities configurations that will be included or excluded from the "core" definition. NERC also requests approval of the proposed "Detailed Information to Support an Exception Request" form as satisfying the requirement in Order No. 743 that NERC develop "technical criteria" to address exception requests. [22] Finally, NERC requests Commission approval of its plan for implementation of the revised definition of "bulk electric system."

a. "Core" Definition of Bulk Electric System

14. NERC proposes the following "core" definition of bulk electric system:

> Unless modified by the [inclusion and exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. [23]

15. NERC states that the core definition eliminates regional discretion and establishes a clear, bright-line based on a 100 kV threshold. NERC states that the core definition places within the bulk electric system "all Transmission Elements operated at 100 kV or above, and all Real Power and Reactive Power resources connected at 100 kV or above," while establishing an express exclusion for facilities used in the local distribution of electrical energy. [24] NERC states that the revised definition deletes the phrase "[a]s defined by the Regional Reliability Organization" that is included in the current definition, eliminating the express basis for regional discretion. [25] NERC explains that the core definition includes the 100 kV criterion as a bright-line threshold, rather than as a general guideline, by eliminating the phrase "generally operated at" found in the current definition. [26]

16. NERC also explains that, while the current definition includes the phrase "associated equipment," and the revised definition does not, "associated equipment" is included in the revised definition by the use of the term "Transmission Elements" included in the revised core definition. NERC states that the NERC Glossary defines "Transmission" as "[a]n interconnected group of lines and associated equipment for the

movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems;" [27] and defines "Elements" as, "[a]ny electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components." [28]

17. NERC states that the revised definition satisfies the Commission's directives and addresses the technical and policy concerns expressed in Order Nos. 743 and 743-A. According to NERC, the explicit basis of authority for Regional Entity discretion in the current definition is eliminated. In addition, NERC states that the core definition establishes specific threshold criteria rather than general guidelines of facilities operated or connected at or above 100 kV. Further, NERC states that the core definition in combination with the specific inclusions and exclusions provides a detailed set of criteria that can be applied on a uniform, consistent basis across all regions, eliminates ambiguity, and eliminates the potential for discretion and subjectivity in determining what facilities are part of or not part of the bulk electric system.

b. Inclusions and Exclusions to the Definition of Bulk Electric System

18. NERC states that, as part of the revised definition, NERC developed inclusions and exclusions to eliminate discretion in application of the revised "bulk electric system" definition. NERC states that the inclusions address five specific facilities configurations to provide clarity that the facilities described in these configurations are included in the bulk electric system (unless the facilities are excluded based on one of the specific exclusions). [29] The five inclusions are:

Inclusions:

I1—Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3.

I2—Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.

I3—Blackstart Resources identified in the Transmission Operator's restoration plan.

I4—Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

I5—Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

19. NERC explains that the facilities described in inclusions I1, I2, I4, and I5 are each operated or connected at or above 100 kV. NERC states that inclusion I3 encompasses blackstart resources identified in a transmission operator's restoration plan, which are necessary for the operation of the interconnection transmission system and should be included in the bulk electric system regardless of their size (MVA) or the voltage at which they are connected. NERC states that the inclusions will further reduce the potential for the exercise of discretion and subjectivity to exclude such configurations from the bulk electric system.

20. According to NERC, inclusion I1 includes transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under exclusion E1 or E3 (discussed later). NERC states that transformers operating at 100 kV or higher are part of the existing definition, but since transformers have windings operating at different voltages, and multiple windings in some circumstances, clarification was required to explicitly identify which transformers are included in the bulk electric system.

21. Inclusion I2 addresses generating resources with a gross individual nameplate rating greater than 20 MVA or a gross plant/facility aggregate nameplate rating greater than 75 MVA. According to NERC, inclusion I2 includes in the bulk electric system the generator terminals through the high-side of the step-up transformers connected at a voltage of 100 kV or above. NERC states that this inclusion mirrors the text of the NERC Registry Criteria (Appendix 5B of the NERC Rules of Procedure) for generating units. [30] NERC states that a "basic tenet that was followed in developing the [revised definition] was to avoid changes to Registrations * * * if such changes are not technically required for the [revised definition] to be complete." [31]

22. As noted above, inclusion I3 includes blackstart resources identified in the transmission operator's restoration plan in the bulk electric system.

23. Inclusion I4 includes dispersed power producing resources with gross aggregate capacity nameplate rating greater than 75 MVA which utilize a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above. NERC states that this inclusion was added to accommodate the effects of variable generation on the bulk electric system.

24. Inclusion I5 addresses static or dynamic devices (excluding generators) dedicated to supplying or absorbing reactive power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in inclusion I1. NERC states that this inclusion is the technical equivalent of inclusion I2 for reactive power devices.

25. NERC states that the four exclusions identify facilities configurations that should not be included in the bulk electric system. [32] Generally, the exclusions address radial systems, behind-the-meter generation and local networks that distribute power to load. The four exclusions are:

Exclusions:

E1—Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

(a) Only serves Load. Or,

(b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

(c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note—A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

E2—A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) The net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

E3—Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk-power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk-power transfer across the interconnected system. The LN is characterized by all of the following:

(a) *Limits on connected generation:* The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

(b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

(c) *Not part of a Flowgate or transfer path:* The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

E4—Reactive Power devices owned and operated by the retail customer solely for its own use.

Note—Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

26. Exclusion E1 provides detailed criteria for determining which facilities are properly excluded from the bulk electric system as radial facilities, which NERC states is intended to enhance the clarity of the radial facilities exclusion. NERC explains that criteria “b” and “c” of exclusion E1 identify the maximum amount of generation allowed on the radial facility while still qualifying for the radial facilities exclusion (aggregate capacity less than or equal to 75 MVA). NERC indicates that this exclusion addresses the circumstances of small utilities (including municipal utilities and cooperatives). According to NERC, “the maximum amount of generation allowed on the radial facility is sufficient to allow small utilities to continue to provide service options that support reliability of the interconnected transmission network, while not operating to exclude larger generators from the [bulk electric system].” [33] Further, NERC states, that the maximum amount of generation allowed on the radial facility per criteria “b” and “c” is

consistent with the aggregate capacity threshold presently provided in the Registry Criteria for registration as a generator owner or generator operator (75 MVA gross nameplate rating).

27. With respect to the "normally open switch" note at the end of exclusion E1, NERC explains that this note is intended to address a common network configuration "in which two separate sets of facilities that, each standing alone, would be recognized as radial systems and not included in the bulk electric system are connected by a `normally open switch'—i.e., a switch that is set to the open position—for reliability purposes." [34] NERC states that a switch in this configuration is installed by entities to provide greater reliability to their end-use customers. According to NERC, scheduled maintenance activities on a radial line, or an unscheduled outage impacting the single point of supply to the radial line, could cause the disruption of power supply to the end-use customers served by the line, unless the entity has the ability to temporarily switch to another feed. [35] NERC states that the entity's operating procedures dictate how and when to operate such a normally open switch. NERC explains that an entity does not arbitrarily close the normally open switch placed in this configuration. Rather, the entity closes the "normally open" switch to maintain reliability of service to its end-use customers served from the affected radial line. NERC believes that facilities that otherwise meet the criteria for the radial system exclusion in exclusion E1 should not be included in the bulk electric system solely because the entity maintains a switch of this type, which is normally open, between sets of radial facilities. NERC states that for a set of radial facilities that are connected by a switch to qualify for the radial exclusion under exclusion E1, the switch must be identified as "normally open" on "source documents such as, prints or one-line diagrams and must in fact be normally set in the open position." [36]

28. NERC states that subjecting two sets of radial facilities that are normally unconnected to each other because the switch between them is open to the Reliability Standards during the limited time periods when the switch is closed for maintenance-related or outage-related circumstances would be fundamentally impractical and unworkable (from both the entity's perspective and the ERO's perspective). [37] NERC explains that this note will prevent numerous exception requests because this configuration is common.

29. According to NERC, exclusion E2 excludes a generating unit or units on the customer's side of the retail meter that serves all or part of the retail load subject to two conditions. First, the net capacity provided by the generating unit does not

exceed 75 MVA. Second, standby, back-up, and maintenance power services are provided to the generating unit or the retail load by a balancing authority, or pursuant to a binding obligation with a generator owner or generator operator, or under terms approved by the applicable regulatory authority. NERC states that these generating units are not necessary for the operation of the interconnected transmission network and, therefore, do not need to be included in the definition because they serve a single retail load, provide a limited amount of capacity to the bulk electric system, and are fully backed up by other resources. [38]

30. NERC explains that exclusion E3, the "local network" exclusion, encompasses local networks of transmission elements operated at between 100 kV and 300 kV "that distribute power to load rather than transfer bulk power across the interconnected system." [39] NERC explains that "[t]he purpose of local networks is to provide local distribution service, not to provide transfer capacity for the interconnected transmission network." [40] According to NERC, a network that supports distribution and does not accommodate bulk-power transfers across the interconnected system should not be included in the bulk electric system. NERC also states that the "detailed conditions established in exclusion E3 are sufficient to ensure that such qualifying local networks are being used exclusively for local distribution purposes." [41] NERC adds that facilities used for the local distribution of electric energy are expressly excluded from the bulk electric system by the core definition as well as by the local network exclusion.

31. Exclusion E4 encompasses reactive power devices owned and operated by a retail customer solely for its own use. NERC explains that exclusion E4 is the technical equivalent of exclusion E2 for reactive power devices.

c. Detailed Information To Support an Exception Request

32. In Order No. 743, the Commission directed NERC to develop a set of technical criteria to use in addressing requests for exceptions to the definition of the bulk electric system. [42] NERC states that it would be "more feasible to develop a common set of data and information that could be used by the Regional Entities and NERC to evaluate exception requests" than to develop the detailed criteria. [43] The Detailed Information Form contains the common set of data that entities seeking an exception must submit with every exception request. NERC indicates that the Detailed Information Form represents an equal and effective alternative approach to developing a

substantive set of technical criteria for granting and rejecting exception requests required in Order No. 743. [44] Thus, NERC asks the Commission to approve the Detailed Information Form as satisfying the Commission's technical concerns expressed in Order No. 743 with respect to the need for criteria to approve or disapprove exception requests.

33. The Detailed Information Form specifies that all exception requests include a one-line breaker diagram identifying the element for which the exception is requested and data and studies to support the submittal. NERC states that the studies should be based on an Interconnection-wide base case to reflect the electrical characteristics and system topology. The studies should clearly document all assumptions used, address key performance measures of bulk electric system reliability through steady state power flow, and contain a transient stability analysis as necessary to support the entity's request. NERC notes that the applicant remains responsible for providing sufficient information and argument to justify the exception request. [45]

34. According to NERC, the information that an applicant may submit in support of an exception request is not limited to the Detailed Information Form. Rather, an applicant is expected to submit all relevant data, studies and other information that supports the exception request. Further, the Regional Entity and NERC may ask an applicant to provide other data and studies in addition to the Detailed Information Form. [46]

d. Proposed Implementation Plan for Revised Definition of "Bulk Electric System"

35. NERC requests that the revised definition "should be effective on the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, the revised [bulk electric system definition] should go into effect on the first day of the second calendar quarter after its adoption by the NERC Board. [47] The existing definition would be retired at midnight of the day immediately prior to the effective date of the revised definition in the jurisdiction in which the revised definition is becoming effective. NERC states that the proposed effective date is appropriate to provide a reasonable time between the date of regulatory approval, which is not under the control of NERC or the industry, and the effective date of the revised BES definition. [48]

36. NERC also requests that compliance obligations for all elements newly-identified to be included in the bulk electric

system based on the revised definition should begin twenty-four months after the applicable effective date of the revised definition. NERC notes that the Commission stated in Order Nos. 743 and 743-A that the transition period should not exceed 18 months from the date of Commission approval of the revised definition, unless the Commission approved a longer transition period based on specific justification. NERC believes that a "somewhat longer transition period" is necessary in light of the actions that will need to be completed in connection with the revised definition. NERC notes that in the United States, the proposed transition period will be between a minimum of approximately twenty-seven months and a maximum of thirty months from the date of Commission approval, depending on the date of Commission approval." [49] NERC states that sufficient time is needed: (1) To implement transition plans to accommodate any changes resulting from the revised definition; (2) for entities to file for exceptions, and for the Regional Entities and NERC to process those exceptions to a final determination, pursuant to the proposed exception process; and (3) for owners of facilities and elements that are newly-included in the bulk electric system based on the definition to train their personnel on compliance with the Reliability Standards applicable to the newly-included facilities and elements, so that these entities can achieve compliance with applicable Reliability Standards by the end of the transition period.

2. NERC Petition for Approval of Revisions to Rules of Procedure To Adopt a Bulk Electric System Exception Process

a. Changes to NERC's Rules of Procedure

37. In Docket No. RM12-7-000, NERC filed proposed revisions to its Rules of Procedure for the purpose of adopting a procedure for entities to obtain an exception from the definition of bulk electric system (NERC ROP Petition). NERC states that the proposed exception process, which is a mechanism to add elements to, and remove elements from, the bulk electric system, addresses the concerns raised in Order No. 743 with respect to the current processes for determining what facilities are part of the bulk electric system and what facilities are not. [50] NERC also states that the exception process "provides for decisions to approve or disapprove exception requests to be made by NERC, rather than by the Regional Entities, thereby eliminating the potential for inconsistency and subjectivity that the Commission was concerned [about, which] was created by having decisions as to what facilities are included in or excluded from the BES made at the Regional Entity level." [51] NERC proposes to add section 509 (Exceptions to the Definition of the

Bulk Electric System), section 1703 (Challenges to NERC Determinations of BES Exception Requests) and Appendix 5C (Procedure for Requesting and Receiving an Exception to the NERC Definition of Bulk Electric System) to NERC's Rules of Procedure. The NERC ROP Petition also includes proposed conforming revisions to other Rules of Procedure, including revisions to sections 302.2, 501.1.4.4, 804, 1102.2, and 1701 and appendices 2, 3D, 4B, 5B, 6, and 8, which NERC states are necessary in light of the revised definition and the exception process.

Section 509 of the Rules of Procedure

38. NERC states that proposed section 509 establishes a procedure, which is contained in a new Appendix 5C to the Rules of Procedure, for an entity to request that an element that falls outside of the definition of the bulk electric system be treated as part of the bulk electric system and for an entity to request that an element that falls within the definition of the bulk electric system not be treated as part of the bulk electric system:

> An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside the definition of the Bulk Electric System should be considered a part of the Bulk Electric System. [52]

NERC explains that the exception process is "not intended to be used to resolve ambiguous situations," i.e. the exception process is only available after an initial determination has been made regarding whether an element is part of or not part of the bulk electric system through the application of the definition to the element. [53]

Appendix 5C to the Rules of Procedure

39. NERC explains that proposed Appendix 5C sets forth the detailed procedures for obtaining an exception to include an element in, or remove an element from, the bulk electric system. [54] The exception process involves three steps. [55] First, an entity applies the bulk electric system definition to a transmission element to determine its status. If the entity believes that the element, contrary to its characterization based

on the definition, should either be treated, or not be treated, as part of the bulk electric system, the entity may submit an exception request to the Regional Entity in which the element is located. Second, the Regional Entity screens the request to determine whether the application meets the filing criteria and, if so, reviews the application and makes a recommendation to NERC whether to approve or deny the request. Third, the NERC President decides whether to approve or deny the exception request after considering the opinion provided by a NERC review panel. [56] If the entity does not agree with the NERC President's decision, it may appeal the decision to the NERC Board of Trustees Compliance Committee (Compliance Committee) who is the final arbiter of the request.

40. According to NERC, if the Regional Entity denies the exception request based on the initial screening but the applicant believes the exception request is proper and complete, the applicant may appeal the rejection directly to NERC.

41. NERC explains that the proposed exception process will allow NERC to provide consistent determinations on exception requests submitted from different regions involving the same or similar facts and circumstances, and will allow NERC to take into account the aggregate impact on the bulk electric system of approving or disapproving all of the exception requests. Finally, the exception process includes provisions for reporting information that may alter the status of an approved exception, verifying whether an exception continues to be warranted, and revoking an exception that is no longer warranted.

42. The proposed exception process includes provisions for obtaining exceptions both for inclusion in and exclusion from the bulk electric system. NERC identifies the entities that are eligible to submit exception requests. Specifically, the owner of an element may submit a request to include the element in, or remove it from, the bulk electric system. [57] A Regional Entity, planning authority, reliability coordinator, transmission operator, transmission planner, or balancing authority that has (or will have upon inclusion in the bulk electric system) the elements covered by an exception request within its scope of responsibility may submit an exception request for the inclusion in the bulk electric system of an element or elements owned by a registered entity. NERC states that only a Regional Entity may submit an exception request for the inclusion in the bulk electric system of an element owned by an owner that is not a registered entity.

43. Finally, NERC states that an exception request will be subject to review to verify continuing justification for the

[58]

exception. According to NERC, the proposed exception process requires an entity to notify the Regional Entity and NERC within 90 days after learning of any change of condition which would affect the basis for approving the exception request. NERC will then review the information and determine whether to direct the Regional Entity to perform a substantive review to verify continuing justification and issue a recommendation to NERC. [59] NERC also states that an entity must certify every 36 months to the appropriate Regional Entity that the basis for the exception request remains valid. In addition, the proposed exception process states that if the Regional Entity obtains information through means other than the submitting entity that indicates an exception may no longer be warranted, the Regional Entity must provide NERC with the information. NERC will review the information and determine whether to direct the Regional Entity to perform a substantive review to verify continuing justification and issue a recommendation to NERC. [60]

44. NERC states that the exception process establishes a process that (1) Balances the need for effective and efficient administration with due process and clarity of expectations; (2) promotes consistency in determinations and eliminates Regional discretion by having all decisions on Exception Requests made at NERC; (3) provides for involvement of persons with applicable technical expertise in making decisions on ception Requests; and (4) should alleviate concerns about a "one-size-fits-all" approach. [61]

Section 1703 of the Rules of Procedure

45. NERC has also proposed to modify its Rules of Procedure to add a procedure for an entity to challenge the NERC decision on an exception request. The entity must file the challenge with the Compliance Committee within 30 days of the date of the NERC decision. The Compliance Committee must issue its decision within 90 days after the submission of the challenge, which the Compliance Committee may extend. NERC states that the Compliance Committee decision will be the final NERC decision on the exception request. In addition, the entity may appeal the final NERC decision to the Commission within 30 days following the date of the Compliance Committee`s decision, or within such time period as the Commission's legal authority permits.

b. NERC's List of Facilities Granted Exceptions

46. In Order No. 743, the Commission stated that NERC should maintain a list of exempted facilities that can be made

available to the Commission upon request. [62] NERC states that the proposed exception process does not include provisions for NERC to maintain a list of facilities that have received exceptions, as requested in Order No. 743, as this is an internal administrative matter for NERC to implement that does not need to be embedded in the Rules of Procedure. [63] NERC states it will develop a specific internal plan and procedures for maintaining a list of facilities for which exceptions have been granted.

47. NERC also notes that Regional Entities will maintain lists of elements within their regions for which exceptions have been granted, in order to monitor compliance with the requirement to submit periodic certifications pursuant to section 11.3 of Appendix 5C. [64]

II. Discussion

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48. Pursuant to section 215(d) of the FPA we propose to approve NERC's revised definition of bulk electric system, including the specific inclusions and exclusions set forth in the definition, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed below, we believe that NERC's proposal satisfies the directives of Order No. 743 to develop modifications to the currently-effective definition of bulk electric system to ensure that the definition encompasses all facilities necessary for operating an interconnected transmission network and remove the Regional Entity discretion that currently allows for regional variations without review or oversight. We also believe NERC's proposed definition satisfies the Commission's technical concerns in Order No. 743 through the use of a bright-line 100 kV threshold, with specific inclusions and exclusions within the definition, for identifying bulk electric system elements and the establishment of an exception process for facilities that are not necessary for operating the interconnected transmission network. Further, we believe NERC's proposed definition improves clarity and transparency. Below, we discuss the proposed “core” bulk electric system definition as well as each bright-line inclusion and exclusion of the proposed definition.

49. While proposing to approve NERC's modified definition, we also seek additional explanation and comments regarding potential applications of the “core” definition, as well as the inclusions and exclusions. We believe that a common understanding of the proposed bulk electric system definition (1) promotes consistent application of the definition in identifying bulk electric system elements and facilities and (2) provides up-front clarity so as to minimize the need for future clarifications either formally through NERC's standards

clarification process or case-specific in a compliance setting. Thus, we seek comment from NERC and other interested persons regarding the scenarios and applications of the NERC proposal, discussed below. Although we propose to approve the definition in this rulemaking, the responses to our questions are also intended to guide the Commission as to whether other action may be necessary, for example, directing NERC to develop a further modification to the core definition, inclusions or exclusions pursuant to section 215(d)(5) of the FPA.

50. Further, pursuant to section 215(f) of the FPA, we propose to approve the revisions to the NERC Rules of Procedure that establish an exception process to determine case-specific exceptions to the bulk electric system definition. NERC's proposal meets the section 215(f) standard of review for changes to the Rules of Procedure. The Detailed Information Form in the proposed rules identifies "base-line" information and data that any applicant must submit. Further, after Regional Entity input, NERC makes the final decision on whether to grant an exception request, which better assures consistency of decisions across all regions.

51. In Order No. 743, the Commission stated that NERC should maintain a list of facilities included or excluded from the bulk electric system pursuant to the exception process. [65] NERC indicates that, while it plans to maintain such a list, maintaining the list is an internal NERC function and, thus, not included in NERC's proposed Rules of Procedure. To understand how NERC intends to comply with the directive from Order No. 743, we propose to require that NERC submit a compliance filing detailing its internal process for tracking exception requests.

52. Below, the Commission discusses (A) the "core" bulk electric system definition; (B) proposed inclusions and exclusions in the definition; (C) the case-specific exception process; (D) the Detailed Information Form; and (E) NERC's implementation plan.

A. The Commission Proposes To Approve the Core Definition of Bulk Electric System

53. The bulk electric system "core" definition developed by NERC states as follows:

Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

54. In Order No. 743, the Commission found that "the current definition of bulk electric system is insufficient to ensure that all facilities necessary for operating an interconnected electric energy transmission network are included under the `bulk electric system' rubric." [66] The Commission also stated that the "aim" of the final rule was to "eliminate inconsistencies across regions, eliminate the ambiguity created by the current discretion in NERC's definition of bulk electric system, provide a backstop review to ensure that any variations do not compromise reliability, and ensure that facilities that could significantly affect reliability are subject to mandatory rules." [67] The Commission stated that the one way to accomplish these goals is to eliminate the regional discretion in the current definition, and maintain the bright-line threshold that includes all facilities operated at or above 100 kV and establish an exception process and criteria for excluding facilities that are not necessary for the operation of the interconnected transmission network. [68]

55. It appears that NERC's proposal satisfies the objectives set forth in Order No. 743. The "core" definition, quoted above, establishes the fundamental threshold for inclusion of facilities in the bulk electric system as those that are operated at 100 kV or higher, if they are transmission elements, or are connected at 100 kV or higher, if they are real power or reactive power resources. The core definition also establishes a 100 kV criterion as a bright-line threshold, rather than as a general guideline as in the current definition, i.e., the phrase "generally operated at" in the current definition is eliminated. As NERC explains, the core definition also continues to capture equipment associated with the facilities included in the bulk electric system. [69]

56. Further, consistent with Order No. 743, NERC's proposed "bulk electric system" definition eliminates the phrase "as defined by the Regional Reliability Organization * * *." As a result, NERC's proposed definition will apply nation-wide. Thus, we believe NERC's proposal adequately addresses the concerns articulated in Order No. 743 regarding unfettered regional discretion and the need for a consistent approach satisfies the concerns regarding the elimination of inconsistencies across regions. The Commission seeks comment on whether the revised definition adequately eliminates subjectivity and regional variation as required in Order No. 743. [70]

57. Below, we seek comment regarding the exclusion of facilities used in local distribution.

Local Distribution

58. In Order No. 743, the Commission acknowledged that "Congress has specifically exempted `facilities used in the local distribution of electric energy' " from the Bulk-Power System definition and that, because such facilities are exempted from the Bulk-Power System, they also are excluded from the bulk electric system. [71] The Commission also stated that, although local distribution facilities are excluded from the definition, it still is necessary to determine which facilities are local distribution, and which are transmission. [72] As the Commission stated in order No. 743-A, "[w]hether facilities are used in local distribution will in certain instances raise a question of fact, which the Commission has jurisdiction to determine." In Order No. 743, the Commission also recognized that NERC would need to establish whether a particular facility is local distribution or transmission, and directed NERC to develop a means, subject to Commission approval, to make such a determination. [73] In Order No. 743-A the Commission clarified that

the statement in Order No. 743, "determining where the line between `transmission' and `local distribution' lies * * * should be part of the exemption process the ERO develops" was intended to grant discretion to the ERO, as the entity with technical expertise, to develop criteria to determine how to differentiate between local distribution and transmission facilities in an objective, consistent, and transparent manner. * * * Once NERC develops and submits its proposal to the Commission, the Commission will, as part of its evaluation of the proposal, determine whether the process developed adequately differentiates between local distribution and transmission.

We agree * * * that the Seven Factor Test could be relevant and possibly is a logical starting point for determining which facilities are local distribution for reliability purposes, while also allowing NERC flexibility in applying the test or developing an alternative approach as it deems necessary. [74]

59. In addressing what constitutes local distribution, NERC explains that the second sentence in the core definition, which excludes "facilities used in the local distribution of electric energy," is consistent with section 215(a)(1)(B) of the FPA and the Commission's regulations at 18 CFR 39.1 and as recognized in Order No. 743-A." [75] NERC states that "the core definition * * * establish[es] an express carve out for facilities used in the local distribution of electrical energy." [76] NERC also states that facilities for the local distribution of electric energy are

expressly excluded from the bulk electric system by the core definition as well as by the local network exclusion, exclusion E3. [77] NERC adds that, while some stakeholders suggested that the Commission's seven-factor test should be employed to determine distribution facilities, the NERC drafting team "rejected this approach as the sole determination of distribution facilities, * * * [but] pointed out that such a test could be utilized by a Submitting Entity making an Exception Request but that other information should be supplied to support the request." [78]

60. The Commission seeks comment from NERC and the public regarding how the proposed definition is responsive to the Commission's directives in Order Nos. 743 and 743-A. Specifically, the Commission seeks comment on how NERC's proposal adequately differentiates between local distribution and transmission facilities in an objective, consistent, and transparent manner. [79]

B. The Commission Proposes To Approve the List of Inclusions and Exclusions in the Definition of Bulk Electric System

61. Along with the core definition, NERC's proposal provides specific inclusions and exclusions. The inclusions and exclusions provide added clarity regarding which elements are part of the bulk electric system as compared to the existing definition. For example, the inclusion of generating resources, blackstart resources and dispersed power producing resources provide additional information and granularity that assist in the identification of bulk electric system facilities or elements. However, we also have questions about how some of the inclusions and exclusions will be applied by NERC, Regional Entities and users, owners and operators of the Bulk-Power System. Through the responses to these questions we seek to better understand potential applications of the inclusions and exclusions, their effect on identifying the facilities or elements for bulk electric system reliability, and whether possible gaps exist.

1. Inclusions

a. Inclusion I1 (Transformers)

62. Inclusion I1 provides "[t]ransformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under [the radial system or local network exclusion]." NERC explains that:

Transformers operating at 100 kV or higher are part of the existing definition, but since transformers have windings operating at different voltages, and multiple windings in some circumstances, clarification was required to explicitly identify which transformers are included in the BES. Inclusion I1 includes in the BES those transformers operating at 100 kV or higher on the primary winding and at least one secondary winding, so as to be in concert with the core definition. [80]

63. We believe that inclusion I1, with NERC's explanation, is a reasonable approach to identifying transformers that are appropriately included as part of the bulk electric system. However, circumstances may warrant inclusion of a particular transformer—through the proposed case-specific exception process—where a transformer is operated at 100 kV or higher on the primary winding but all secondary terminals are operated below 100 kV. The joint NERC and Commission staff report on the September 8, 2011, Arizona-Southern California blackout discusses how a 92 kV networked system experienced parallel flows from bulk electric system elements through two 230/92 kV transformers. [81] The report explains that the reliability coordinator, transmission operators and balancing authorities did not consider certain sub-100 kV facilities, including two 230/92 kV transformers as bulk electric system elements. Consequently, when contingencies occurred on the bulk electric system on September 8, 2011, the reliability coordinator, transmission operators and balancing authorities were unaware that the contingencies adversely impacted the 230/92 kV transformers or how the loss of the transformers impacted system reliability. [82] The Commission seeks comment on whether these types of transformers, i.e., those that have a terminal operated at 100 kV or above on the high side and below 100 kV on the low side should be designated as part of the bulk electric system. If answered in the affirmative, the Commission seeks further comment whether the case-by-case exception process suffices, or a generic inclusion is appropriate to address the concerns identified in Order No. 743.

b. Inclusion I2 (Generating Resources)

64. Inclusion I2 provides:

Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.

According to NERC, this inclusion “mirrors” the text of the

NERC *Registry Criteria* for generating units. NERC explains that the drafting team "found no technical rationale for changing at this time from the thresholds for generating resources presently specified in the * * **Registry Criteria*." [83] Further, NERC states that, to provide clarity, the revised definition specifies that the bulk electric system "includes the generator terminals through the high-side of the step-up transformer connected at a voltage of 100 kV or above." [84]

65. We believe that Inclusion I2 provides useful granularity regarding the inclusion of generation resources as part of the bulk electric system. However, we seek comment regarding several aspects of inclusion I2. NERC's Registry Criteria thresholds for generators provides for the registration of "[i]ndividual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the Bulk Power System" or "[g]enerating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the Bulk Power System at a common bus with total generation above 75 MVA gross nameplate rating." [85] We agree that proposed inclusion I2 is consistent with the individual and aggregate nameplate rating thresholds set forth in the Registry Criteria. We note, however, that the Registry Criteria and the proposed definition differ regarding the description of the connection point of the generating units and plants. While inclusion I2 specifies "generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above," the Registry Criteria specifies a "direct connection" to the Bulk-Power System. We seek comment whether inclusion I2 will result in a material change to registration of existing generating units due to the difference in the language regarding the connection point. In addition, we seek comment if, pursuant to inclusion I2, the following circumstances are included in the bulk electric system: A generating unit, with a gross individual nameplate rating greater than 20 MVA connected through the high-side of the step-up transformer connected at a voltage of 100 kV or above *when the low side of the transformer is less than 100 kV*. How does this result differ for a generation resource with two or more step-up transformers where the last transformer in the series operates at 100 kV or above, for example, a 50 MVA generator first steps up through a 23 kV transformer on the low side and 69 kV on the high side and then immediately steps up through a second transformer at the same site with less than 100 kV on the low side and above 100 kV on the high side?

c. Inclusion I3 (Blackstart Resources Identified in the

Transmission Operator's Restoration Plan)

66. Inclusion I3 identifies as part of the bulk electric system "Blackstart Resources identified in a Transmission Operator's restoration plan." NERC explains that blackstart resources are "vital" for the reliable operation of the bulk electric system and are included "regardless of their size (MVA) or the voltage at which they are connected." [86] NERC further states that including blackstart resources is consistent with the *Registry Criteria*, which provide that "*any generator, regardless* of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan" is eligible for registration. [87]

67. We agree with NERC that inclusion of blackstart resources in the definition is vital to reliability and is an improvement to the definition. We seek clarification whether the term "restoration plan" refers to the system restoration plans required in the Emergency Preparedness and Operations (EOP) Reliability Standards or included in a Commission approved tariff. [88]

68. NERC states that first posting of the revised definition included "cranking paths" for blackstart resources due to a concern about "the possibility of having Blackstart Resources without a `guaranteed' path" to the [bulk electric system]." [89] NERC explains that "a number of commenters complained that this was improperly bringing distribution level Elements into the [bulk electric system], as many Cranking Paths are at the distribution level" and "also pointed out that this was an illusory proposition as intended Cranking Paths are not always the ones used in actual restoration." [90] As a result of the industry feedback, NERC deleted cranking paths from the revised definition with the understanding that the issue would be revisited in Phase 2 of the BES project. According to NERC, "this approach would maintain status quo on this topic, consistent with Order Nos. 743 and 743-A, while providing for a full discussion and consideration of the issue in a less time constrained environment". [91] [92] Subsequently, however, the topic of cranking paths was deleted from the scope of the Phase 2 BES project. [93] In light of the decision not to further pursue a possible revision to the bulk electric system definition pertaining to cranking paths, the Commission is concerned whether a reliability gap exists with regard to cranking paths. Cranking paths constitute a basic element of system restoration, and it is unclear whether reliability can be adequately maintained when blackstart generators are defined as part of the bulk electric system but not the transmission paths that are

used to deliver the energy from blackstart generators to the integrated transmission system. We also recognize that cranking paths may implicate facilities used in local distribution. Accordingly, we seek comment on whether a reliability gap may exist with regard to cranking paths and, if so, what potential approaches are appropriate to remove the gap. We also seek comment on the appropriate role, if any, of state regulators in ensuring that energy from blackstart generation is reliably delivered through cranking paths to restart the system after an event.

d. Inclusion I4 (Dispersed Power Producing Resources)

69. Inclusion I4 identifies as part of the bulk electric system:

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

70. NERC explains that this inclusion is intended "to accommodate the effects of variable generation" on the bulk electric system. [94] NERC further states that even though inclusion I4 could be considered subsumed in inclusion I2 (generating resources), NERC believes it is appropriate "to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity." [95]

71. We believe that inclusion I4 provides useful granularity in the bulk electric system definition. To better understand the application of inclusion I4, we seek comment whether this provision includes as part of the bulk electric system the individual elements (from each energy-producing resource at the site through the collector system to the common point at a voltage of 100 kV or above) used to aggregate the capacity and any step-up transformers used to connect the system to a common point at a voltage of 100 kV or above.

e. Inclusion I5 (Static or Dynamic Reactive Power Devices)

72. Inclusion I5 identifies as part of the bulk electric system:

Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

NERC explains that this inclusion is the technical equivalent of inclusion I2 (generating resources), for reactive power devices and points out that the existing definition is unclear as to how these devices are treated. [96] NERC states inclusion I5 provides clarity by "providing specific criteria for Reactive Power devices, thereby further limiting subjectivity and the potential for discretion" in the application of the revised definition. [97]

73. The Commission agrees with NERC that this inclusion adds clarity to the application of the bulk electric system definition by providing specific criteria for reactive power devices. For cases where the reactive power device is connected through a transformer designated in inclusion I1, we seek comment on whether both the reactive power device and the transmission elements connecting the reactive power device to the transformer are included as part of the bulk electric system pursuant to inclusion I5.

2. Exclusions

74. NERC states that the proposed definition identifies four facilities configurations that should not be included in the bulk electric system: (1) Radial systems, (2) behind-the-meter generating units, (3) local networks, and (4) retail customer reactive power devices.

75. We agree that the proposed definition's exclusions provide clarity and granularity. For example, the exclusion of generating units on the customer's side of the retail meter that serves all or part of the retail load (exclusion E2) and the exclusion for reactive power devices owned and operated by a retail customer for its own use (exclusion E4) provide reasonable limitations on bulk electric system elements. While we believe that the exclusions provide added clarity, we also seek comment on certain aspects of exclusions E1 and E3 to ensure a more complete understanding of their application.

a. Exclusion E1 (Radial Systems)

76. Exclusion E1 provides as follows:

Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

(a) Only serves Load. Or,

(b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

(c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note—A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

NERC states that radial facilities are excluded under the currently effective bulk electric system definition, and the detailed criteria in the revised definition provide enhanced clarity. [98] We seek comment on our understanding and NERC's explanation of exclusion E1 in order for the Commission to ensure application of exclusion E1 is consistent. Also, we seek comment to determine if the configurations covered by Conditions (a), (b), or (c) of exclusion E1 remove from the bulk electric system generation connected to a radial system that otherwise satisfies inclusion I2. The Commission would like to ensure that the conditions in exclusion E1 will not lead to conflicting results when applying inclusion I2 and exclusion E1.

77. As stated above, the radial exclusion applies to "a group of contiguous *transmission* Elements that emanates from a single point of connection of 100 kV or higher. * * *" While the term "Elements" includes the term generator, [99] the use of the term "transmission" before "Elements" indicates that exclusion E1 applies only to transmission elements. The phrase "transmission Elements" in this provision does not apply to generating resources that are bulk electric system resources pursuant to inclusion I2 (generating resources), connected to a radial line operated at 100 kV above. [100]

i. Definition of `Radial Systems' and Condition (a)—Radials Only Serving Load

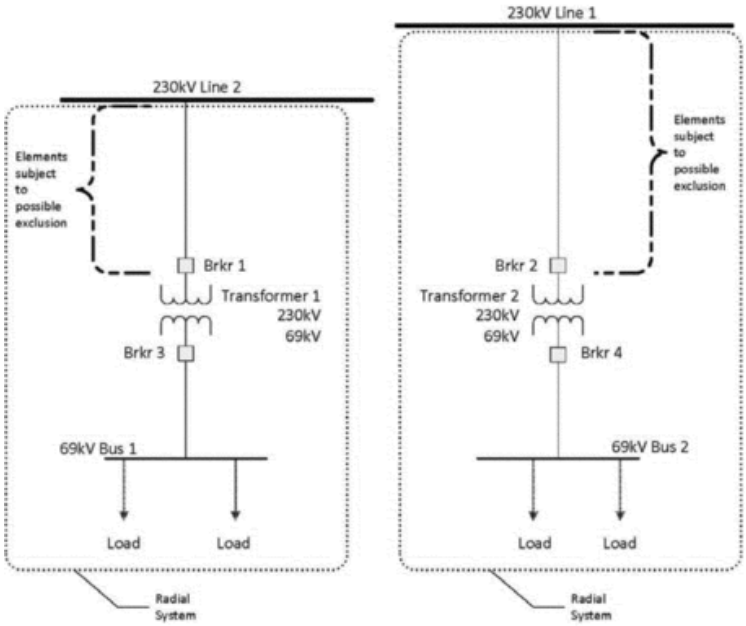
78. NERC stated that it developed exclusion E1 to provide enhanced clarity as compared to the existing definition. [101] Exclusion E1 defines the term `radial systems' as "a group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher." The Commission seeks comment on how NERC's proposal would be applied in the three scenarios described below.

79. Figure 1 below depicts facilities configurations in which all of the 230 kV and 69 kV transmission elements emanate from a single point of connection of 100 kV or higher. The Commission seeks comment on whether each of the radial systems shown in figure 1, the 230 kV elements above each transformer to the point of connection to each 230 kV line,

respectively, are excluded from the bulk electric system pursuant to exclusion E1.

Figure 1

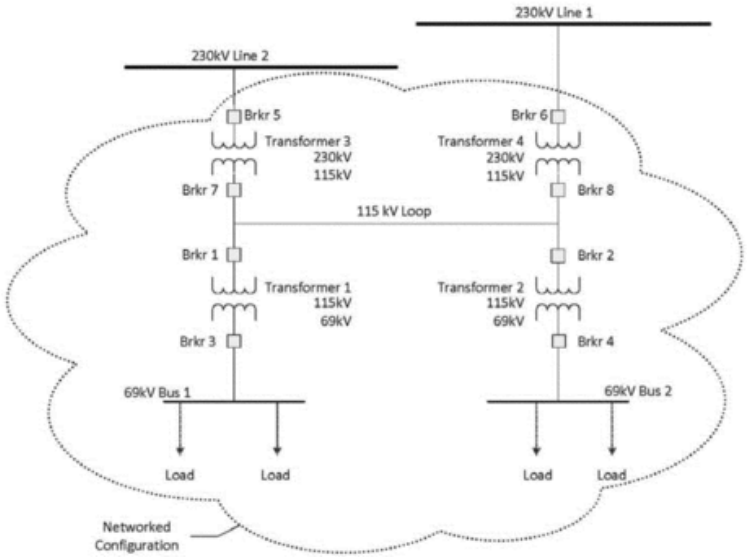
Two Radial Systems Eligible for Exclusion E1



80. Another scenario shown in figure 2 below depicts a configuration containing a 115 kV loop, with the configuration emanating from two points of connection of 100 kV or higher. We seek comment whether, in this configuration, the 115 kV and 230 kV elements above Transformers 1 and 2 to the points of connection to the two 230 kV lines would be excluded from the bulk electric system pursuant to exclusion E1. Is the configuration shown in figure 2 more appropriately analyzed pursuant to the "local network" exclusion E3 and, if so, what if any elements operated at or above 100 kV would be excluded pursuant to exclusion E3?

Figure 2

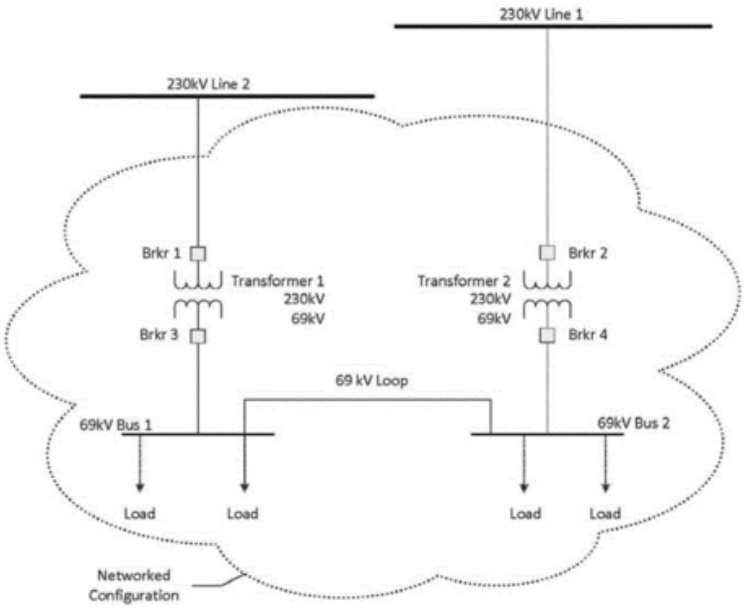
Networked Configuration w/115 kV Loop



81. The Commission agrees with NERC that `radial systems' only serving load and emanating from a single point of connection of 100 kV or higher should be excluded from the bulk electric system. The Commission is concerned that the exclusion could allow elements operating at 100 kV or higher in a configuration that emanates from two or more points of connection to be deemed “radial” even though the configuration remains contiguous through elements that are operated below 100 kV. For example, figure 3 below depicts a configuration with two points of connection of 100 kV or higher that are contiguous through a 69 kV loop. We seek comment on how to evaluate the configuration in figure 3 vis-à-vis the radial system definition and whether it is appropriate to examine the elements below 100 kV to determine if the configuration meets the exclusion E1 definition for radial systems. In other words, does figure 3 depict a system emanating from two points of connection at 230 kV and, therefore, the 230 kV elements above the transformers to the points of connection to the two 230 kV lines would not be eligible for the exclusion E1 notwithstanding the connection below 100 kV?

Figure 3

Networked Configuration w/69 kV Loop



ii. Condition (b)—Radials With Limited Generation and Condition (c)—Radials With Limited Generation and Load

Condition (b) of exclusion E1 provides that a radial system is excluded if it "[o]nly includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating)." Proposed Condition (c) of exclusion E1, excludes radial systems "[w]here the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating)."

82. NERC states that Conditions (b) and (c) are "intended to address the circumstances of small utilities (including municipal utilities and cooperatives)." [102] The NERC BES Petition, including the Exhibit E record of development, does not further explain the need for, or the impact of, these proposed provisions. Accordingly, we seek comment regarding the specific circumstances that Conditions (b) and (c) are intended to address.

83. Because Condition (b) describes generation connected to a radial system with no load and Condition (c) describes generation connected to a radial system with generation and load, it appears that the power generated on these radial systems would, by design, be delivered or injected to the bulk electric system and transported to other markets. In this circumstance, it appears that a line 100 kV or above connected

to a generator with a capacity 75 MVA or below would not be included in the bulk electric system. The Commission seeks comment on the appropriateness of excluding such radials.

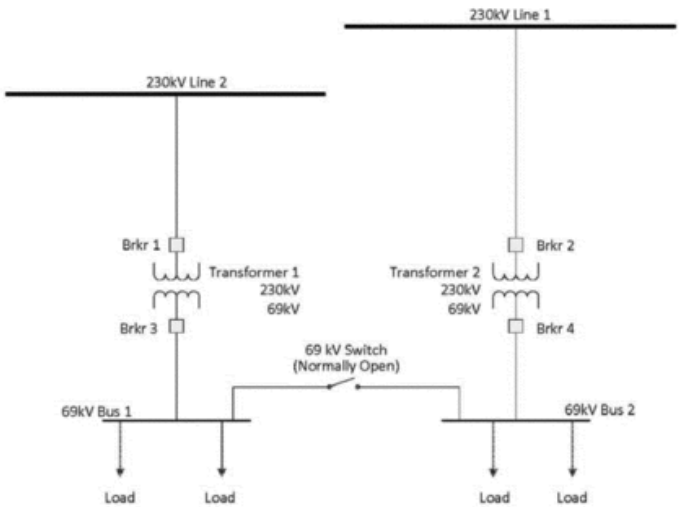
iii. Normally Open Switches

84. Proposed exclusion E1 includes a "note" stating that a "normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion." NERC states that this note is intended to address a common network configuration in which two separate sets of facilities that, each standing alone, would be recognized as radial systems but are connected by a switch that is set to the open position for reliability purposes. [103]

85. NERC explains that these switches are installed by entities to provide greater reliability to their end-use customers. For example, when the entity schedules maintenance activities on a radial line or an unscheduled outage occurs that impacts a single point of supply to the radial line which could cause the disruption of power supply to the end-use customers served by the line, the switch allows the entity to use another feed on the connected radial line.

86. Figure 4 below illustrates a configuration with a normally open switch.

Figure 4
69 kV Networked Configuration with Normally Open Switch



NERC states that "[t]he concept that two sets of radial facilities that are normally unconnected to each other should be subject to * * * applicable Reliability Standards during the limited time periods when they are connected by the closing of the normally open switch in the maintenance-related or outage-related circumstances described above would be fundamentally

impractical and unworkable (from both the entity's perspective and the ERO's perspective), and would misapprehend this very common, reliability-driven facilities configuration." [104]

87. NERC states that "a normally open switch" will be identified in documents such as prints or one-line diagrams and that "[t]he concept and usage of the `normally open switch' in such configuration is well understood in the electric utility industry." [105] We seek comment on NERC's characterization and whether the phrase "normally open" is subject to interpretation or misunderstanding, or whether a "normally open" configuration is potentially difficult to oversee. Further, we seek comment on the need of transmission operators or other functional entities to study the system impacts of the closing of a "normally open" switch, or to take other steps to ensure awareness of the impacts of the loop that is created by the closing of the switch if the closed loop is not included as part of the bulk electric system.

b. Exclusion E2 (Behind the Meter Generation)

88. Exclusion E2 excludes "[a] generating unit or multiple generating units on the customer's side of the retail meter * * *." The Commission believes that this is an appropriate exclusion that provides additional clarity and granularity to the definition of bulk electric system.

c. Exclusion E3 (Local Networks)

89. As noted above, we believe that a common understanding of the exclusions promotes consistent application of the definition in identifying bulk electric system elements. In particular, as discussed in greater detail below, we seek comment on the following issues with respect to the application of exclusion E3: (1) Whether generation resources are excluded by this exclusion; (2) how the exclusion applies to a looped lower voltage system; (3) whether the 300 kV ceiling is appropriate for the application of the exclusion; (4) whether the prohibition for generation produced inside a local network is not transporting power to other markets outside the local network applies in both normal and emergency operating conditions.

90. Exclusion E3 defines the term local networks as:

A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk-power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer

Load and not to accommodate bulk-power transfer across the interconnected system.

Exclusion E3 also identifies three conditions that must be satisfied for the exclusion to apply: (a) Limit on connected generation to 75 MVA aggregate capacity of non-retail generation (gross nameplate rating); (b) power flows only into the local network and does not transfer through the `local network'; and (c) the local network is not part of a flowgate or transfer path.

91. NERC states the design and operation of local networks is such that at the point of connection with the interconnected transmission network is similar to that of a radial facility, in particular that power always flows in a direction from the interconnected transmission network into the local network. [106] Further, according to NERC, "[l]ocal networks provide local electrical distribution service and are not planned, designed or operated to benefit or support the balance of the interconnected transmission network." [107]

92. Similar to our discussion of the definition of `radial systems' in exclusion E1, the exclusion E3 local network exclusion applies to transmission Elements, but does not apply to generation resources connected to a local network that otherwise satisfy inclusion I2.

93. NERC states in the LN Technical Paper, that "Exclusion E3 was specifically designed to capture for exclusion those high voltage non-radial facilities being used for the local distribution of energy." [108] The paper further provides:

Their [local network] design and operation is such that at the point of connection with the interconnected electric transmission network, their effect on that network is similar to that of a radial facility, particularly in that flow always moves in a direction that is from the BES into the facility. Any distribution of parallel flows into the local network from the BES, as governed by the fundamentals of parallel electric circuits, is negligible, and, more importantly, is overcome by the Load served by the local network, thereby ensuring that the net actual power flow direction will always be into the local network at all interface points. The presence of a local network is not for the operability of the interconnected electric transmission network; neither will the local network's separation or retirement diminish the reliability of the interconnected electric transmission network." [109]

94. We seek further explanation and comment on the statement above that "neither will the local network's separation

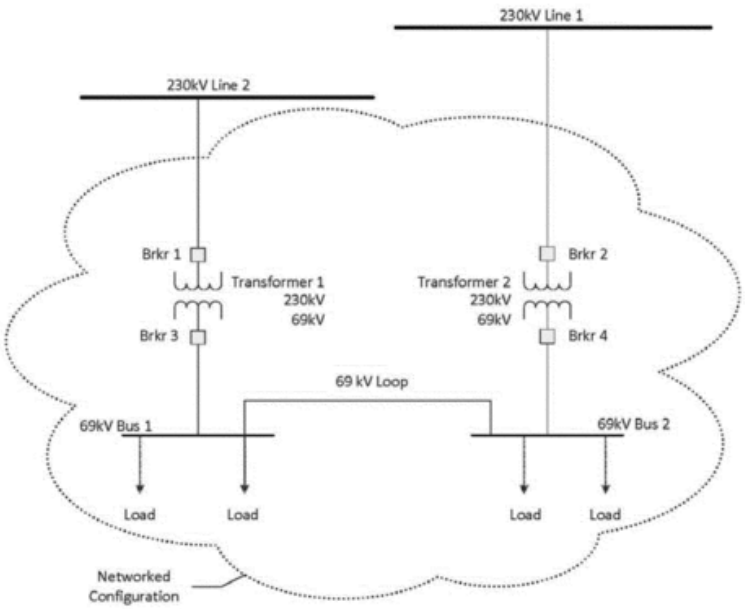
or retirement diminish the reliability of the interconnected electric transmission network." While a radial facility emanates from one point of connection to the interconnected transmission network, a local network by definition has multiple points of connection to the interconnected transmission network. Thus, regarding a local network, a contingency situation may arise where one of the multiple connections to the interconnected transmission network separates, while other local network connections maintain connectivity with the bulk electric system. We seek comments to better understand how an entity with a candidate local network would analyze such contingencies to determine potential impacts to the reliable operation of the interconnected transmission network.

i. Contiguous Transmission Elements and the 100 kV Lower Limit/300 kV Cap

95. As stated above, exclusion E3 defines local networks as "[a] group of *contiguous* transmission Elements *operated at or above 100 kV but less than 300 kV* that distribute power to Load rather than transfer bulk-power across the interconnected system." While the local network exclusion applies to contiguous transmission elements operating at a minimum of 100 kV, it is unclear how the exclusion applies to a looped lower voltage system. For example, figure 5 depicts a 69 kV looped system emanating from two points of connection at 100 kV or higher.

Figure 5

Networked Configuration w/69 kV Loop



The configuration in figure 5 depicts a group of elements

that are contiguous through a 69 kV loop. We seek comment whether the configuration in figure 5 qualifies as a local network and, in particular, whether the configuration satisfies the condition that a local network consists of "a group of *contiguous* transmission Elements *operated at or above 100 kV** * *."

96. NERC states the selection of a 300 kV cap for the applicability of an exclusion for a local network was based upon recent NERC standards development work in Project 2006-02 "Assess Transmission Future Needs and Develop Transmission Plans" which sets a voltage level of 300 kV to differentiate extra high voltage (EHV) facilities from high voltage facilities acting as a threshold to distinguish between expected system performance criteria. [110] NERC states that it seeks to establish consistency in the limitations placed on the exclusion applicability for local network facilities, and has therefore adopted this 300 kV level to ensure that EHV facilities are not subject to this exclusion. [111] NERC provides a "realistic example of the electrical interaction between a typical local network and the [bulk electric system]" in the LN Technical Paper. [112] The example depicted in Appendix 1 of the Technical Paper shows a local network operating at 115 kV. The NERC Technical Paper does not provide examples of a local network operating within the 200 to 300 kV range, for example showing 230 kV facilities operating in a local network. We are concerned whether the 300 kV ceiling is appropriate and reflects actual system configurations that serve local distribution, the stated purpose of the local network exclusion. [113] Accordingly, we seek comment whether (and why or why not) the 300 kV ceiling is appropriate for the application of exclusion E3 and requests examples of systems between 200 and 300 kV that would qualify for this exclusion. [114]

ii. Criterion (a)—Limits on Connected Generation

97. Exclusion E3 criterion (a) provides that the local network and its underlying elements do not include the blackstart resources identified in inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA gross nameplate rating. In addition, criterion (a) does not limit the amount of generation besides "non-retail generation" connected to the local network. The Commission agrees with NERC that "local networks" do not include blackstart resources and agrees with the limits on the connected generation imposed by this exclusion.

iii. Criterion (b)—Power Flows Only Into the Local Network

98. Exclusion E3 criterion (b) specifies that to be eligible for the exclusion, power can only flow into the local network and the local network does not transfer energy originating outside the local network for delivery through the local network. Thus, it appears that, pursuant to criterion (b), generation produced inside a local network is not transporting power to other markets outside the local network. The Commission understands that criterion (b) applies in both normal and emergency operating conditions. [115]

iv. Criterion (c)—Not Part of a Flowgate or Transfer Path

99. Exclusion E3 criterion (c) specifies a "local network" does not contain a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an interconnection reliability operating limit. The Commission believes that this is an appropriate criterion.

d. Exclusion E4 (Reactive Power Devices)

100. Exclusion E4 excludes from the bulk electric system "Reactive Power devices owned and operated by the retail customer solely for its own use." NERC explains that exclusion E4 is the technical equivalent of Exclusion E2 for reactive power devices and that the currently effective bulk electric system definition is unclear as to how these devices are to be treated. We believe that this is an appropriate exclusion that provides additional clarity and granularity to the definition of bulk electric system.

Summary

101. In sum, we propose to approve NERC's revised definition of the term bulk electric system, including the specific inclusions and exclusions. We believe that NERC's proposal provides a reasonable basis for the identification of bulk electric system elements and appears to improve upon the currently effective definition by: (1) Removing the language that provides for regional discretion, (2) removing the language "generally operated at * * *" so as to create a clear 100 kV threshold; and (3) providing additional clarity and granularity. Above, we have asked for comment on a series of questions regarding the applicability of the "core" definition and specific inclusions and exclusions. We believe that comments on these questions will assist in providing further clarity and understanding of the

NERC proposal. We further note that although we propose to approve the definition in this rulemaking, the responses to our questions are intended to guide the Commission as to whether other action is necessary, for example, by directing NERC to develop a further modification to the definition or inclusions/exclusions pursuant to section 215(d)(5) of the FPA.

C. The Commission Proposes To Approve the NERC Rules of Procedure That Provide a Case-Specific Exception Process

102. As described above, in Docket No. RM12-7-000, NERC submitted proposed revisions to its Rules of Procedure that provide procedures for requesting and receiving case-specific exception from the definition of bulk electric system. [116]

103. Pursuant to FPA section 215(f), we propose to find that the exception process is just, reasonable, not unduly discriminatory or preferential, and in the public interest and satisfies the requirements of section 215(c). Further, we believe that the proposal satisfies the statement in Order No. 743 that NERC establish an exception process for excluding facilities that are not necessary for the reliable operation of the interconnected transmission network from the definition of the bulk electric system. [117]

104. NERC explains that it was not feasible to develop a single set of technical criteria that would be applicable to all exception requests so it developed the Detailed Information Form to ensure that a consistent baseline of technical information is provided for NERC to make a decision on all exception requests. This information and the proposed exception process allows NERC to provide consistent determinations on exception requests submitted from different regions involving the same or similar facts and circumstances, and allows NERC to take into account the aggregate impact on the bulk electric system of approving or denying all the exception requests. Finally, the exception process includes provisions for reporting information that may alter the status of an approved exception, verifying whether an exception continues to be warranted, and revoking an exception that is no longer warranted. [118] Thus, we believe that this process is equally efficient and effective as the Order No. 743 directive to establish an exception process for excluding facilities that are not necessary for the reliable operation of the interconnected transmission network. In addition, we believe that NERC's proposal appears to be clear, transparent, and uniformly applicable.

105. NERC and the industry should be commended for the development of the 100 kV threshold, the identified inclusions and exclusions, and the exception process. Together, this package of important reforms will bring valuable improvements to the process of identifying those facilities that are necessary for the operation of the interconnected transmission network, and thus should be included in the definition of bulk electric system. For these reasons, we propose to approve NERC's proposals, as discussed above.

106. The Commission seeks input from NERC and the industry, however, as to additional reforms that may be needed to the definition or to the Rules of Procedure to ensure that, over the long term, the facilities necessary to the reliability of the interconnected transmission network are captured in its definition. In particular, we note that while establishing a "bright-line" threshold of 100 kV has significant advantages, it may not capture all facilities that are necessary for the operation of the interconnected transmission network that fall below that threshold. As the Commission indicated in Order No. 743 and Order No. 743-A, its goal is that the definition of bulk electric system should include all facilities necessary for the operation of the interconnected transmission network, except for local distribution. Although the Commission indicated that one way to meet this goal was to establish a 100 kV "bright-line" threshold, the Commission also made clear that the "bright-line" threshold would be a "first step or proxy" in determining which facilities should be included in the bulk electric system. [119] Indeed, the Commission, agreeing with commenters, held that NERC should not necessarily stop at 100 kV and should, through the development of the exception process, ensure that "critical" facilities operated at less than 100 kV, and that the Regional Entities determine are necessary for operating the interconnection network. [120] The Commission clarified that including sub-100 kV facilities should be done in an "appropriate and consistent" manner. [121]

107. Recent events reinforce the Commission's statements in Order Nos. 743 and 743-A with respect to ensuring that sub-100 kV facilities, as appropriate, are included in the bulk electric system. The September 2011 Blackout Report concluded that certain sub-100 kV facilities, which were not designated as bulk electric system facilities, contributed to the cascading blackout affecting San Diego, California. [122] The September 2011 Blackout Report makes clear that, while certain sub-100 kV facilities can affect bulk electric system reliability, entities may not study or communicate their impacts and take appropriate action unless they are properly designated as part of

the bulk electric system. [123] Thus, the September 2011 Blackout Report recommended that "WECC, as the [Regional Entity], should lead other entities, including [transmission operators] and [balancing authorities], to ensure that all facilities that can adversely impact [Bulk-Power System] reliability are either designated as part of the [bulk electric system] or otherwise incorporated into planning and operations studies and actively monitored and alarmed in [real-time contingency analysis] systems." [124] Although the Blackout Report addressed an event in WECC, the recommendations in the Blackout Report should not be limited only to the Western interconnection. Indeed, as explained above, the recommendation in the September 2011 Blackout Report that sub-100 kV facilities be reviewed for inclusion in the bulk electric system is consistent with the Commission's findings in Order Nos. 743 and 743-A.

108. The NERC proposals at issue in this NOPR take steps to address the treatment of sub-100 kV facilities, as well as other facilities, necessary for the operation of the interconnected transmission network, through the exception process, which provides an avenue for Regional Entities, planning authorities, reliability coordinators, transmission operators, transmission planners, balancing authorities, and owners of system elements to submit a request to include a facility in the bulk electric system. We believe that regional entities, reliability coordinators, transmission owners, transmission operators, balancing authorities and other registered entities need to evaluate their sub-100 kV facilities, as well as other facilities, that are necessary to operate the interconnected transmission network in an "appropriate and consistent" manner to determine their potential impacts on bulk electric system reliability and, based on that review, seek to include those facilities in the bulk electric system through this proposed exception process. [125] These entities have the in-depth, "on the ground" knowledge and expertise of what facilities are critical to reliable operations in their local or regional area. As a result, we believe they bear primary responsibility to analyze the elements within their purview to ensure that the right facilities are included in the bulk electric system. We seek comment on how the relevant entities will conduct the review and seek inclusion of facilities.

109. The Commission expects that these entities will use the exception process as contemplated to include sub-100 kV facilities, and other facilities, necessary for the operation of the interconnected transmission network in the bulk electric system. Nonetheless, we note that relying on these entities

alone may, in certain limited circumstances, have the potential to leave out sub-100 kV facilities necessary for the operation of the interconnected transmission network. For example, NERC or the Commission may, in the performance of their statutory functions and general oversight of reliability matters, discover additional sub-100 kV facilities that should be included. The joint NERC-FERC September 2011 Blackout Report, as noted above, is a prime example of this possibility. In addition, while we recognize that the owners and operators of the power grid take their reliability obligations seriously, there may be instances when not all of the facilities necessary for the operation of the interconnected transmission network are included in the bulk electric system.

110. Thus, while we propose to approve the package of reforms submitted by NERC, we seek comment on how the relevant entities will seek inclusion of sub-100 kV elements to ensure that all facilities that are necessary for the operation of the bulk power system are designated as bulk electric system elements consistent with the discussion above. These comments also should aid NERC, industry, and the Commission in further efforts, already underway in Phase 2, to refine the bulk electric system definition, the inclusions and exclusions, and the exception process.

111. In addition to general comments on the discussion above, we seek comments on the role NERC should have in initiating the designation of (or directing others to initiate the designation of) sub-100 kV facilities, or any other facilities, necessary for the operation of the interconnected transmission network for inclusion in the bulk electric system. The exception process as proposed does not provide that NERC may initiate an exception request. Given its statutory functions to develop and enforce Reliability Standards and its continent-wide perspective, NERC has technical understanding that may provide valuable assistance in the identification of bulk electric system facilities and elements. For example, NERC conducts disturbance assessments, oversees compliance monitoring and conducts seasonal assessments, all of which provide information and understanding regarding the operations of the bulk electric system. The Commission seeks comment on the role NERC should have in designating sub-100 kV facilities, and other facilities, for inclusion in the bulk electric system, directing Regional Entities or others to conduct such reviews, or itself nominating an element to be included in the bulk electric system. [126]

112. We also seek comment on the role the Commission should have with respect to the designation of sub-100 kV

facilities, or other facilities, necessary for the operation of the interconnected transmission network for inclusion in the bulk electric system. As noted above, there may be circumstances (like the September 2011 Blackout Report) where the Commission, through the performance of its statutory functions, may conclude that certain sub-100 kV facilities not already included in the bulk electric system are necessary for the operation of the interconnected transmission network and thus should be included in the bulk electric system. While, as noted above, we expect that regional entities and others will take affirmative steps to review and include sub-100 kV elements and facilities, and other facilities, necessary for the operation of the interconnected transmission system in the bulk electric system, we seek comment as to how the Commission, if necessary, could ensure that such facilities are considered for inclusion in the bulk electric system. We also seek comment on instances when the Commission itself should designate (or direct others to designate) sub-100 kV facilities, or other facilities, necessary for the operation of the interconnected transmission grid for inclusion in the bulk electric system. [127]

1. Technical Review Panel

113. NERC's proposed exception process provides that "[t]he Regional Entity shall not recommend Disapproval of the Exception Request in whole or in part without first submitting the Exception Request for review to a Technical Review Panel and receiving its opinion * * *" [128] The technical review panel member must have the required technical background, must not have participated in the review of the exception request, and not have a conflict of interest in the matter. [129] The Regional Entity is not bound by the opinion of the panel, but the panel's evaluation becomes part of the record associated with the exception request and provided to NERC.

114. We see value in the Regional Entity receiving the independent opinion of a qualified technical review panel. NERC, however, does not explain why the proposed rules only require a technical review panel to provide an opinion where the Regional Entity recommends disapproval of an exception request. We seek comment from NERC explaining whether it considered obtaining the opinion of a technical panel for all Regional Entity recommendations and, if so, why the review is only required when a Regional Entity disapproves a request. Further, we seek comment on whether NERC should modify the exception process to require Regional Entities to submit all proposed determinations to a technical review panel regardless of the recommendation and receive the panel's opinion on each

request.

2. Use of Industry Subject Matter Experts

115. Section 8 of the proposed exception process sets forth the procedures for NERC's review of a Regional Entity's recommendation. The NERC President will appoint a team of at least three persons with the technical background to evaluate an exception request. The members of the review team must have no financial, contractual, employment or other interest in the submitting entity or owner that would present a conflict of interest and must be free of any conflicts of interest in accordance with NERC policies. [130] NERC states that "at the present time NERC anticipates that its review teams would be drawn from NERC staff resources, supplemented by contractors as necessary particularly where needed to provide specific relevant subject matter expertise. However, situations may arise in which NERC may need to call on industry subject matter experts to participate as members of review teams." [131]

116. We support NERC's proposal to use staff resources, supplemented by contractors as necessary, to make up the exception request review teams. We believe that consistent appointment of the same NERC staff and contractor resources, based on subject matter expertise, will promote a more uniform and consistent review of the Regional Entities' exception request recommendations.

D. The Commission Proposes To Approve NERC's Detailed Information Form

117. As described above, NERC developed the Detailed Information Form that the Regional Entity and NERC can use in evaluating whether or not the elements that are the subject of an exception request are necessary for operating the interconnected transmission network. The Detailed Information Form encompasses a wide range of potential configurations and appears to ensure that a consistent baseline of technical information is provided with all exception requests, in addition to the specific information and arguments provided by the submitting entity in support of its exception request. The information that the applicant may submit in support of an exception request will not be limited to the Detailed Information Form. The applicant will be expected to submit all relevant data, studies and other information that supports its exception request. Further, NERC may ask the submitting entity to provide other data, studies and information in addition to the Detailed Information Form and the other information included by the applicant in the exception request.

118. We believe that this information will provide consistency with respect to the technical information provided with all exception requests and is an equally efficient and effective approach to developing a substantive set of technical criteria for granting and rejecting exception requests. Accordingly, we propose to approve the Detailed Information Form included in NERC's filing.

E. The Commission Proposes To Approve NERC's Implementation Plan for the Revised Definition of Bulk Electric System

119. As noted above, NERC requests that the revised definition "should be effective on the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, the revised [bulk electric system definition] should go into effect on the first day of the second calendar quarter after its adoption by the NERC Board. [132]

120. NERC also requests that compliance obligations for all elements newly-identified to be included in the bulk electric system based on the revised definition should begin twenty-four months after the applicable effective date of the revised definition. While the Commission stated in Order Nos. 743 and 743-A that the transition period should not exceed 18 months from the date of Commission approval of the revised definition, the Commission also stated that it could approve a longer transition period based on specific justification. [133] NERC states that sufficient time is needed: (1) To implement transition plans in order to accommodate any changes resulting from the revised definition; (2) for entities to file for exceptions, and for the Regional Entities and NERC to process those exceptions to a final determination, pursuant to the proposed exception process; and (3) for owners of facilities and elements that are newly-included in the bulk electric system based on the definition to train their personnel on compliance with the Reliability Standards applicable to the newly-included facilities and elements, so that these entities can achieve compliance with applicable Reliability Standards by the end of the transition period. We believe that NERC has provided adequate justification for its implementation plan, as discussed above. Thus, although NERC's plan exceeds the 18 month implementation period set forth in Order No. 743, we propose to approve NERC's implementation plan.

F. NERC List of Facilities Granted Exceptions

121. In Order No. 743, the Commission stated that "a Commission staff audit would review the application of the exemption criteria developed by NERC in NERC's or a Regional Entity's determination to approve an exemption for a particular facility." The Commission also stated that "to facilitate such audits, the ERO should maintain a list of exempted facilities that can be made available to the Commission on request. NERC can decide how best to maintain the list, including determining whether or not to post it on the NERC Web site." [134]

122. NERC states that the proposed exception process does not include provisions for NERC to maintain a list of facilities that have received exceptions, as this is an internal administrative matter for NERC to implement that does not need to be embedded in NERC Rules of Procedure. [135] NERC states it will develop a specific internal plan and procedures for maintaining a list of facilities for which exceptions have been granted. Further, NERC explains that it has not yet determined how the list will be organized and structured and under what conditions the list will be made available on the NERC Web site or otherwise made available to any entities other than the Commission, citing concerns about confidential information and critical energy infrastructure information. [136]

123. We understand that NERC is continuing to develop the details on how it will maintain the list of facilities that have received exceptions. However, we also consider the maintenance of this list of facilities an important feature for tracking exceptions. [137] Thus, we propose that NERC file an informational filing within 90 days of the effective date of a final rule, detailing its plans to maintain a list and how it will make this information available to the Commission, Regional Entities, and potentially to other interested persons. We seek comment from NERC whether this deadline provides adequate time for NERC to finalize its plans and submit an informational filing.

124. While NERC states that it will maintain a list of facilities that have received an exception pursuant to the case-specific exception process, the petition does not indicate whether NERC will track an entity's "declassification" of current bulk electric system facilities based on the entity's self-application of the bulk electric system definition. It appears that, in some circumstances, the appropriate Regional Entity would receive a request that an entity be removed from the NERC Compliance Registry. For example, if an entity determines that its entire system satisfies the exclusion E1 for radial systems, the entity could apply to the appropriate Regional Entity to be removed from the NERC Compliance

Registry. However, in other circumstances, it is not clear what, if any, notification an entity would provide to NERC or a Regional Entity when the entity self-determines that an element is no longer part of the bulk electric system. For example, a large utility with hundreds or thousands of transmission lines may initially determine that a configuration on its system does not qualify for the exclusion E3 local network exclusion, but subsequently determines that the configuration can be excluded. NERC's petition does not indicate whether an entity in such circumstance is obligated to inform NERC or the appropriate Regional Entity of that self-determination. It appears that NERC and the Regional Entities would need this information for their compliance programs, for audit purposes, and to understand the contours of the bulk electric system within a particular region. Accordingly, we seek comment on whether NERC's proposal should be modified to include an obligation for the registered entity to inform NERC or the Regional Entity of the entity's self-determination through application of the definition and specific exclusions E1 through E4 that an element is no longer part of the bulk electric system.

III. Information Collection Statement

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125. The following collection of information contained in this Proposed Rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995. [138] OMB's regulations require approval of certain information collection requirements imposed by agency rules. [139] The Commission solicits comment on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically the Commission asks that any revised burden estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated.

126. In Order No. 693, the Commission approved NERC's definition of the term bulk electric system and the associated information requirements.

127. In Order No. 743, the Commission directed NERC to develop a revised “bulk electric system” definition. The Commission explained that, by directing NERC to develop a revised definition, “the Commission is maintaining the status quo (i.e., the current bulk electric system definition) until the Commission approves a revised definition. Thus, the Commission's action does not add to or increase entities'

reporting burden." [140]

128. The immediate NOPR proposes to approve the revision to the definition of "bulk electric system" developed by NERC and an exception process to include or exclude specific elements in the definition of "bulk electric system" on a case-by-case basis. The Commission is basing its burden estimate below on the revised definition of "bulk electric system" developed by NERC.

129. The proposal in this NOPR would result in entities reviewing systems and creating qualified asset lists, submitting exception requests where appropriate, and certain responsible entities having to comply with requirements to collect and maintain information in mandatory Reliability Standards with respect to certain facilities for the first time.

130. *Public Reporting Burden:* While the Commission requests comment concerning the information collections proposed in this NOPR and the associated burden estimates, in particular, the Commission requests comment on the following issues.

131. First, we request comment on the estimated number of entities that will have an increased reporting burden associated with the identification of new bulk electric system elements as a result of the modified definition. NERC states in its filing that "[i]t was not the intent nor the expectation of either the [standard drafting team] or NERC to either expand or reduce the scope of the [bulk electric system], or (with the likely exception of the NPCC Region) to increase or decrease the number of Elements included in the [bulk electric system], through the revised [bulk electric system] definition as compared to the current [bulk electric system] definition." [141] NERC adds that it has no specific basis to determine to "the extent Elements currently included in the [bulk electric system] will become not included, nor to what extent Elements currently not included will become included." [142] In developing an estimate of the reporting burden associated with the inclusion of additional elements, like NERC, we assume that entities in the NPCC Region will be most affected, with a lesser affect in other regions. [143]

132. We reviewed Compliance registry information for the NPCC Region to determine the number and types of registered entities in the U.S. portion of the NPCC Region. [144]

We expect that transmission owners and distribution providers, and some generator owners, are most likely to identify new elements. Based on this, we estimate a range from

66 to 155 affected entities in the NPCC region, and for OMB reporting purposes identify below a median number of 111 affected entities in the NPCC region. Further, consistent with NERC's explanation, we do not expect a significant number of registered entities outside of the NPCC region to identify new elements under the revised bulk electric system definition. Accordingly, we estimate a total of 75 entities outside of the NPCC Region having new "implementation plan and compliance" related reporting burdens. We seek comment on these estimates to assist the Commission in arriving at final estimates.

133. Second, we seek comment on the reporting burden associated with exception requests. NERC indicates that "there is currently not a basis for estimating the numbers of Exceptions Requests that will be submitted * * *." [145] We agree with NERC that there is difficulty in estimating a specific number of exception requests as this is a new process with no "track record." Thus, rather than estimating a specific number of exception requests, we estimate a range of exception requests that may be submitted. As indicated in the table below, from the 1,730 total transmission owners, generator owners and distribution providers in the Compliance Registry, we estimate a range of 87 to 433 exception requests per year for each of the first two years after the effective date of a final rule. We request comment on this estimated range to assist the Commission in arriving at a final estimate of the number of possible exception requests.

134. Third, as indicated above, our estimates are based in part on an expectation that transmission owners, generator owners and distribution providers will experience more significant reporting burdens than other categories of registered entities. We seek comment on this expectation, and whether and to what extent other categories of registered entities (in addition to transmission owners, generator owners and distribution providers) may have a public reporting burden.

135. We estimate that the increased Public Reporting Burden for this Proposed Rule is as follows:

Requirement	Number and type of entity[146]	Number of responses per entity	Average number of hours per response	Total burden hours
	(1)	(2)	(3)	(1)*(2)*(3)
System Review and List Creation[147]	333 Transmission Owners	1 response	80 (engineer hours)	26,640 Yr 1.

	843 Generator Owners		16 (engineer hours)	13,488 Yr 1.
	554 Distribution Providers		24 (engineer hours)	13,296 Yr 1.
Exception Requests[148]	1,730 total Transmission Owners, Generator Owners and Distribution Providers	.15 responses in Yrs 1 and 2	94 (60 engineer hrs, 32 record keeping hrs, 2 legal hrs)	24,393 hrs in Yrs 1 and 2.
		0.01156 responses in Yr 3 and ongoing		1,880 hrs in Yr 3 and ongoing.
Regional and ERO Handling of Exception Requests[149]	NERC and 8 Regional Entities	1 response	1,386.67 hrs	12,480 hrs in Yrs 1 and 2.
Implementation Plans and Compliance[150]	111 NPCC Region Registered Entities[151]	1 response	700 hrs in Yrs 1 and 2	77,700 hrs in Yrs 1 and 2.
			350 hrs in Yr 3 and ongoing	38,850 hrs in Yr 3 and ongoing.
	75 Registered Entities from 7 other Regions	1 response	700 hrs in Yrs 1 and 2	52,500 hrs in Yrs 1 and 2.
			350 hrs in Yr 3 and ongoing	26,250 hrs in Yr 3 and ongoing.
Totals				220,497 hrs in Yr 1.
				167,073 hrs in Yr 2.
				66,980 hrs in Yr

				3 and ongoing.

Information Collection Costs: The Commission seeks comment on the costs to comply with these requirements. These cost estimates are calculated using the average of the ranges suggested in the burden hour estimates. It has projected the annual cost to be:

- *Year 1:* $13,641,200.
- *Year 2:* $10,435,760.
- *Year 3 and ongoing:* $4,343,520.

For the first two burden categories above, the loaded (salary plus benefits) costs are: $60/hour for an engineer; $27/hour for recordkeeping; and $106/hour for legal. The breakdown of cost by item and year follows:

- *System Review and List Creation (year 1 only):* (26,640 hrs + 13,488 hrs + 13,296 hrs) = 53,424 hrs * 60/hr = $3,205,440.
- *Exception Requests (years 1 and 2):* (sum of hourly expense per request * number of exception requests) = ((60 hrs * $60/hr) + (32 hrs * $27/hr) + (2 hrs * $106/hr)) * 260 requests) = $1,215,760.
- *Exception Requests (year 3):* (sum of hourly expense per request * number of exception requests) = ((60 hrs * $60/hr) + (32 hrs * $27/hr) + (2 hrs * $106/hr)) * 20 requests) = $93,520.
- *Regional and ERO handling of Exception Requests:* Between NERC and regional entities we estimate 6 full time equivalent (FTE) engineers will be added at an annual cost of $120,000/FTE ($120,000/FTE * 6 FTE = $720,000). This cost is only expected in years 1 and 2.
- *Implementation Plans and Compliance* [152] *(years 1 and 2):* (hourly expense per entity * hours per response * sum of NPCC and non-NPCC entities) = ($64/hour * 700 hours per response * 186 responses) = $8,332,800.
- *Implementation Plans and Compliance (year 3 and beyond):* We estimate the ongoing cost for year 3 and beyond, at 50% of the year 1 and 2 costs, to be $4,166,400.

Title: FERC-725-J "Definition of the Bulk Electric System."

[153]

Action: Proposed Collection of Information.

OMB Control No.: To be determined.

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: The proposed revision to NERC's definition of the term bulk electric system, if adopted, would implement the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the proposal would ensure that certain facilities needed for the operation of the nation's bulk electric system are subject to mandatory and enforceable Reliability Standards.

Internal Review: The Commission has reviewed the proposed definition and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimate associated with the information requirements.

136. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, email: *DataClearance@ferc.gov*, phone: (202) 502-8663, fax: (202) 273-0873].

137. Comments concerning the information collections proposed in this NOPR and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by email to OMB at the following email address: *oira_submission@omb.eop.gov*. Please reference FERC-725J and the docket numbers of this Proposed Rulemaking (Docket Nos. RM12-6-000 and RM12-7-000) in your submission.

IV. Regulatory Flexibility Act Analysis

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138. The Regulatory Flexibility Act of 1980 (RFA) [154] generally requires a description and analysis of Proposed Rules that will have a significant economic impact on a substantial number of

small entities. As discussed above, the Commission believes that the immediate effect of the proposal to approve the modification to the definition of bulk electric system and the exception process would likely be limited to certain transmission owners, generator owners and distribution service providers, as well as NERC and Regional Entities. Many transmission owners, generator owners and distribution service providers do not fall within the definition of small entities. [155] The Commission estimates that approximately 418 [156] of the 1,730 registered transmission owners, generator owners and distribution service providers may fall within the definition of small entities. [157]

139. The Commission estimates that of the 418 small entities affected there are 50 within the NPCC region that would have to comply with the Proposed Rule. The Commission assumes that the Proposed Rule would affect more small entities in the NPCC Region than those outside NPCC as it is assumed that there are more elements in NPCC that would be added to the bulk electric system based on the new definition than elsewhere. The Commission estimates the first year affect on small entities within the NPCC region to be $39,414. [158] This figure is based on information collection costs plus additional costs for compliance. [159] The Commission estimates the average annual affect per small entity outside of NPCC will be less than for the entities within NPCC. The Commission does not consider this to be a significant economic impact for either class of entities because it should not represent a significant percentage of the operating budget. Accordingly, the Commission certifies that this Proposed Rule will not have a significant economic impact on a substantial number of small entities. The Commission seeks comment on this certification.

V. Environmental Analysis

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140. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment. [160] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination. [161] Accordingly, neither an environmental impact statement nor environmental assessment is required.

VI. Comment

141. The Commission invites interested persons to submit

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comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due September 4, 2012. Comments must refer to Docket Nos. RM12-6-000 and RM12-7-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

142. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov*. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

143. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

144. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

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145. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

146. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

147. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. Email the Public Reference Room at *public.referenceroo*

m@ferc.gov.

LIST OF SUBJECTS IN 18 CFR PART 40

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Electric power; Electric utilities; Reporting and recordkeeping requirements.

By direction of the Commission. Commissioner Clark voting present.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012-15944 Filed 7-3-12; 8:45 am]

BILLING CODE 6717-01-P

FOOTNOTES

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1. 16 U.S.C. 824o (2006).
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2. *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 133 FERC ¶ 61,150, *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011).
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3. *See* 16 U.S.C. 824o(e)(3) (2006).
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4. *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).
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5. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006) (certifying NERC as the ERO responsible for the development and enforcement of mandatory Reliability Standards), *aff'd sub nom. Alcoa Inc.* v. *FERC*, 564 F.3d 1342 (DC Cir. 2009).
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6. *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
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7. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 75 n. 47 (quoting NERC's definition of “bulk electric system”).
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8. *Id.* P 75; *see also* Order No. 693-A, 120 FERC ¶ 61,053 at P 19 (“the Commission will continue to rely on NERC's definition of bulk electric system, with the appropriate

regional differences, and the registration process until the Commission determines in future proceedings the extent of the Bulk-Power System").
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9. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 77 (footnotes omitted).
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10. Order No. 743, 133 FERC ¶ 61,150 at P 16.
Back to Context

11. *Id.*
Back to Context

12. *Id.* P 113.
Back to Context

13. Order No. 743-A, 134 FERC ¶ 61,210 at P 11.
Back to Context

14. *Id.* P 47.
Back to Context

15. *Id.*
Back to Context

16. *See* Order No. 743-A, 134 FERC ¶ 61,210 at PP 40, 67, 102-103.
Back to Context

17. *Id.* P 68.
Back to Context

18. *Id.* P 69.
Back to Context

19. *Id.* P 70.
Back to Context

20. *Id.* PP 25, 58.
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21. "Exclusion" refers to configurations of elements NERC has identified within the revised definition of bulk electric system that should not be included in the bulk electric system. In contrast, an "exception" refers to an element that falls within the bulk electric system definition but is found not to be necessary for the operation of the grid through the proposed exception process, or an element that an element that falls outside of the bulk electric system definition but is found through the exception process should be part of the bulk electric system. Thus, an "exception" may result in adding elements to, or removing elements from, the definition of bulk electric system. Also, NERC uses the term "exception" rather than the term "exemption" used in Order No. 743. *See* Order

No. 743, 133 FERC ¶ 61,150 at P 115.
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22. The Detailed Information to Support an Exception Request is part of the exception process even though NERC filed it as part of the BES Petition. *See* NERC BES Petition at 25-26. Thus, the Commission will address the Detailed Information in the context of the NERC BES Petition rather than in the section of this NOPR addressing the exception procedure petition.
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23. *Id.* at 13.
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24. *Id.* at 16. The current definition and Order No. 743 use the term "facility." NERC proposes to use the term "Element" as used in the NERC Glossary.
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25. *Id.* at 15.
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26. *Id.* at 16.
Back to Context

27. *Id.* at 15 n. 13.
Back to Context

28. *Id.*
Back to Context

29. *Id.* at 16.
Back to Context

30. *Id.* at 17 (citing section III.c.1 and III.c.2 of Appendix 5B of the Rules of Procedure).
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31. *Id.* at 17.
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32. *Id.* at 18.
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33. *Id.* at 19.
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34. *Id.*
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35. As explained below, the switch, though normally open, could be closed in such circumstances to allow the affected radial line to serve load by relying on another line through the closed switch.
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36. *Id.* at 20 n. 26. NERC provides other examples of source documents such as diagrams displayed within an energy management system or a SCADA system.
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37. *Id.* at 20-21.
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38. *Id.* at 21.
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39. *Id.* at 22.
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40. *Id.*
Back to Context

41. *Id.* at 23. *See also id.* at Exh. G (Technical Justification Paper for "Local Network Exclusion") at 2 (LN Technical Paper).
Back to Context

42. Order No. 743, 133 FERC ¶ 61,150 at P 115 (stating "NERC should develop an exemption process that includes clear, objective, transparent and uniformly applicable criteria for the exemption of facilities that are not necessary for operating the grid.").
Back to Context

43. NERC BES Petition at 26.
Back to Context

44. *Id.* at 26, 32 (citing Order No. 743, 133 FERC ¶ 61,150 at P 115).
Back to Context

45. *Id.* at 30.
Back to Context

46. *Id.* at 27 n.32.
Back to Context

47. *Id.* at 34.
Back to Context

48. *Id.*
Back to Context

49. *Id.* at 35.
Back to Context

50. NERC ROP Petition at 4.
Back to Context

51. *Id.* (footnote omitted).
Back to Context

52. *Id.* at 10.

Back to Context

53. *Id.* at 10-11.
Back to Context

54. *Id.* at 11. *See* also section D.1.c above.
Back to Context

55. *Id.* at 13-14.
Back to Context

56. The panel will have at least three members. NERC ROP Petition at 14.
Back to Context

57. Section 5C of NERC's Rules of Procedure defines "owner" as "the owner(s) of an [e]lement or [e]lements that is or may be determined to be part of the [bulk electric system] as a result of either the application of the [bulk electric system] [d]efinition or an [e]xception, or another entity, such as an operator, authorized to act on behalf of the owner of the [e]lement or [e]lements in the context of an [e]xception [r]equest."
Back to Context

58. *Id.* at 34 and Att. 1 at 17.
Back to Context

59. *Id.* at 34-35 and Att. 1 at 17.
Back to Context

60. *Id.* at 35 and Att. 1 at 17.
Back to Context

61. *Id.* at 17.
Back to Context

62. Order No. 743, 133 FERC ¶ 61,150 at P 117.
Back to Context

63. NERC ROP Petition at 49.
Back to Context

64. *Id.*
Back to Context

65. Order No. 743, 133 FERC ¶ 61,150 at P 117.
Back to Context

66. Order No. 743, 133 FERC ¶ 61,150 at P 30.
Back to Context

67. *Id.* P 2.
Back to Context

68. *Id.*
Back to Context

69. The core definition includes all "Transmission Elements

operated at or above 100 kV." As NERC explains in its petition, the NERC-defined term "Transmission" includes the phrase "associated equipment." The NERC Glossary defines "Transmission" as "[a]n interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Additionally, the Glossary defines "Elements" as "[a]ny electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components." We agree with NERC that while the new definition does not use the term "associated equipment," the phrase is included in the definition through the defined term "Transmission Elements."

Back to Context

70. *Id.* PP 11-12, 57. The Commission notes that nothing in the immediate rulemaking proceeding should impact the application of available transmission capability (ATC) calculations as set for in Order No. 890. *See Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 196, *order on reh'g,* Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890-D, 129 FERC ¶ 61,126 (2009). Public utility transmission service providers (or their designate) have the obligation to comply in all respects with their Commission approved tariff. This requires that they must continue to use the applicable Reliability Standards to plan and operate both their bulk electric system and non-bulk electric system facilities included in their tariffs.

Back to Context

71. Order No. 743, 133 FERC ¶ 61,150 at P 37.

Back to Context

72. Order No. 743-A, 134 FERC ¶ 61,210 at P 67.

Back to Context

73. Order No. 743, 133 FERC ¶ 61,150 at P 37.

Back to Context

74. Order No. 743-A, 134 FERC ¶ 61,210 at PP68-69 (footnotes omitted).

Back to Context

75. NERC BES Petition at 16.

Back to Context

76. *Id.* at 22-23.
Back to Context

77. NERC's LN Technical Paper, Exhibit G of NERC's Petition, provides:

> In Order 743a, the Commission made it clear that facilities that are used in the local distribution of electric energy will be excluded from the Bulk Electric System. * * * In response to this facet of the Order, in developing the BES definition, the SDT has followed this guidance. Exclusion E3 was specifically designed to capture for exclusion those high voltage non-radial facilities being used for the local distribution of energy.
>
> The exclusion characteristics in items a, b, and c * * * serve to ensure that facilities excluded under the local network exclusion (E3) are not necessary for the reliable operation of the interconnected electric transmission network and are instead used in the local distribution of energy.
>
> *Id.*, Ex. G, at 2.

Back to Context

78. NERC BES Petition at 49.
Back to Context

79. We note that an element that falls outside of the definition of bulk electric system is not necessarily local distribution.
Back to Context

80. NERC BES Petition at 17.
Back to Context

81. Arizona-Southern California Outages on September 8, 2011—Causes and Recommendations at 96 (September 2011 Blackout Report), *available at http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf*.
Back to Context

82. *Id.* at 96-97.
Back to Context

83. NERC BES Petition at 17. NERC states “A basic tenet that was followed in developing the revised BES Definition was to avoid changes to Registrations due to the revised BES Definition if such changes are not technically required for the BES Definition to be complete.”*Id.* (citing Order No. 743-A, 134 FERC ¶ 61,210 at P 102).
Back to Context

84. NERC BES Petition at 17.
Back to Context

85. Registry Criteria, III.c.1 and c.2 (Generator

Owner/Operator).
Back to Context

86. NERC BES Petition at 18.
Back to Context

87. *Id.* (emphasis added).
Back to Context

88. Reliability Standard EOP-005-1, System Restoration Plans, requires a transmission operator to create "a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system."
Back to Context

89. NERC BES Petition at 47. The NERC Glossary defines "Cranking Path" as "[a] portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units."*See also* the Regional Bulk Electric System Definition Coordination Group concept paper that recommends including the designated cranking paths for the blackstart resources available at *http://www.nerc.com/docs/standards/sar/Project_2010-17_Concept_Paper.pdf*.
Back to Context

90. *Id.*
Back to Context

91. *Id.* NERC's Project 2010-17, the "Phase 2 BES Project."
Back to Context

92. *Id.* NERC's Project 2010-17, the "Phase 2 BES Project."
Back to Context

93. The February 21-23, 2012 meeting notes from the Project 2010-17 Definition of Bulk Electric System Phase 2 Standard Drafting Team states that "the SDT decided to delete the Cranking Path reference in the [Phase 2] SAR." The reasons for the deletion included "that Cranking Paths reach down into distribution and thus shouldn't be included in the definition," and "that this issue was debated in Phase 1 and resolution was obtained," and "that Cranking Paths were only needed when an entity was in restoration mode so it wasn't needed in the definition." However, the same document states some commenters believe "that Cranking Paths were only needed when an entity was in restoration * * * and * * * that this was a reason to have it in the definition."*See* Meeting Notes from the Project 2010-17 Definition of Bulk Electric System Phase 2 Standard Drafting Team, February 21-23, 2012, at Page 5, *available at http://www.nerc.com/docs/standards/dt/Meeting_Notes-Project_2010-17_DBES-February_*

21-23,_2012.pdf.
Back to Context

94. NERC BES Petition at 18.
Back to Context

95. *Id.*
Back to Context

96. *Id.*
Back to Context

97. *Id.*
Back to Context

98. *Id.*
Back to Context

99. "Element" is defined in the NERC Glossary as "[a]ny electrical device with terminals that may be connected to other electrical devices *such as a generator,* transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components." (emphasis added).
Back to Context

100. Our understanding comports with the NERC standard drafting team's explanation in response to industry comments that generation resources connected within the radial system are not excluded pursuant to exclusion E1. *See* NERC BES Petition, Exh. D, Consideration of Comments Report, at 223 (stating that "Exclusion E1 is an exclusion for the contiguous transmission Elements connected at or above 100 kV. Generation resources connected within the radial system are qualifiers for this exclusion.").
Back to Context

101. NERC BES Petition at 18.
Back to Context

102. NERC BES Petition at 19.
Back to Context

103. NERC BES Petition at 19-20.
Back to Context

104. *Id.* at 20-21.
Back to Context

105. *Id.* at 19.
Back to Context

106. NERC BES Petition at 22.
Back to Context

107. *Id.*
Back to Context

108. NERC BES Petition, Exhibit G at 2.
Back to Context

109. *Id.*
Back to Context

110. NERC BES Petition at 23.
Back to Context

111. *Id.* at 23 and Exh. G at 4.
Back to Context

112. *Id.*, Exh. G at 5.
Back to Context

113. The Commission notes additional differentiations may directly address this concern, such as applying a load limit, which was raised by the NERC System Analysis and Modeling Subcommittee (SAMS) in its effort to support Phase 2 of the bulk electric system definition project as a criterion to limit the exclusion of large cities and regions.
Back to Context

114. To the extent the information requested is confidential, commenters may provide the information pursuant to 18 CFR 388.112 of the Commission's regulations.
Back to Context

115. *See* NERC BES Petition, Exh. E at 59 ("The Commission directed NERC to revise its BES definition to ensure that the definition encompasses all Facilities necessary for operating an interconnected electric Transmission network. The SDT interprets this to include operation under both normal and Emergency conditions * * *.").
Back to Context

116. *See* Section I.D.2 above for further description of NERC's proposed revisions to the NERC Rules of Procedure.
Back to Context

117. *See* Order No. 743, 133 FERC ¶ 61,150 at P 16.
Back to Context

118. NERC ROP Petition at 16.
Back to Context

119. Order No. 743-A, 134 FERC ¶ 61,210 at P 40.
Back to Context

120. Order No. 743, 133 FERC ¶ 61,150 at P 121.
Back to Context

121. Order No. 743-A, 134 FERC ¶ 61,210 at P 103.
Back to Context

122. *See* September 2011 Blackout Report at 96-97.
Back to Context

123. *Id.* at 7-8.
Back to Context

124. *Id.* at 96, Recommendation 17.
Back to Context

125. NERC's performance of a final review of exception requests under the Rules of Procedure should ensure national consistency under that procedure.
Back to Context

126. Since NERC makes the final determination pursuant to the proposed process, a modified process may need to be created if NERC has a role in submitting requests. For example, a different entity would likely need to make the final determination.
Back to Context

127. The Commission contemplates that, if it were to take such a step, it would provide an opportunity for notice and comment.
Back to Context

128. NERC ROP Petition, Att. 1, Proposed App. 5C to the Rules of Procedure, section 5.2.4.
Back to Context

129. *Id.* at App. 5C, section 5.3.
Back to Context

130. NERC ROP Petition at 31.
Back to Context

131. *Id.* at n. 29.
Back to Context

132. NERC BES Petition at 34.
Back to Context

133. Order No. 743, 133 FERC ¶ 61,150 at P 131.
Back to Context

134. *Id.* PP 117, 119.
Back to Context

135. NERC ROP Petition at 49.
Back to Context

136. *Id.*
Back to Context

137. Order No. 743, 133 FERC ¶ 61,150 at PP 117, 119.
Back to Context

138. 44 U.S.C. 3507(d) (2006).
Back to Context

139. 5 CFR 1320.11 (2011).
Back to Context

140. Order No. 743, 133 FERC ¶ 61,150 at P 157.
Back to Context

141. NERC BES Petition at 37.
Back to Context

142. *Id.*
Back to Context

143. While Reliability Standards do not require the reporting of information directly to the Commission, the application of Reliability Standards to additional facilities will have associated information collection and retention obligations.
Back to Context

144. NPCC Compliance Registry information is available on the NPCC Web site at: *https://www.npcc.org/Compliance/Default.aspx*.
Back to Context

145. NERC BES Petition at 38.
Back to Context

146. The "entities" listed in this table are describing a role a company is registered for in the NERC registry. For example, a single company may be registered as a transmission owner and generator owner. The total number of companies applicable to this rule is 1,522, based on the NERC registry. The total number of estimated roles is 1,730.

147. This requirement corresponds to Step 1 of NERC's proposed transition plan, which requires each U.S. asset owner to apply the revised bulk electric system definition to all elements to determine if those elements are included in the bulk electric system pursuant to the revised definition. *See* NERC BES Petition at 38.

148. We recognize that not all 1,730 transmission owners, generator owners and distribution providers will submit an exception request. Rather, from the total 1,730 entities, we estimate an average of 260 requests per year in the first two years, based on a low to high range of 87 to 433 requests per year. Therefore, the estimated total number of hours per year for years 1 and 2, using an average of 260 requests per year, is 24,393 hours. We estimate 20 requests per year in year 3 and ongoing.

149. Based on the assumption of two full-time equivalent employees added to NERC staff and 0.5 full-time equivalent employees added to each region's staff, each full-time equivalent at $120,000/year (salary + benefits).

150. The Commission does not expect a significant

number of registered entities outside of the NPCC region to identify new elements under the revised bulk electric system definition. NERC also states that the other Regional Entities do not expect an extensive amount of newly-included facilities. *See* NERC BES Petition at 38. "Compliance" refers to entities with new elements under the new bulk electric system definition required to comply with the data collection and retention requirements in certain Reliability Standards that they did not previously have to comply with.

151. The estimated range of affected NPCC Region Registered Entities is from 66 to 155 entities.
Back to Context

152. The cost and hourly burden calculations for this category are based on a past assessment (NPCC Assessment of Bulk Electric System Definition, September 14, 2009.). In that assessment NPCC indicated $8.9 million annually for operations, maintenance and additional costs. We estimated that roughly half of that cost actually relates to information collection burden. Using the resulting figure, we used a composite wage and benefit figure of $64/hour to estimate the hourly burden figures presented in the burden table.
Back to Context

153. All of the information collection requirements for years 1-3 in the proposed rule are being accounted for under the new collection FERC-725J.
Back to Context

154. 5 U.S.C. 601-612 (2006).
Back to Context

155. The RFA definition of "small entity" refers to the definition provided in the Small Business Act (SBA), which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. *See* 15 U.S.C. 632 (2006). According to the SBA, an electric utility is defined as "small" if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.
Back to Context

156. We note that in Order No. 693, the Commission estimated that the Reliability Standards in that the Final Rule would apply to approximately 682 small entities. *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1940. Because the current Proposed Rule would affect a smaller subset of the categories of registered entities, our estimate is lower than that cited in Order No. 693.

Back to Context

157. The number of small entities is generated by comparing the NERC compliance registry with data submitted to the Energy Information Administration on Form EIA-861. Note, these numbers do not account for companies that may be registered in more than one role. For companies registered in more than one role, the burden will likely be higher than for those companies registered in only one role. We estimate that there are 381 companies and 418 registered roles, meaning that several companies are registered in more than one role. We do not believe this affects the certification below.
Back to Context

158. For companies registered as more than one entity in the NERC compliance registry this figure will increase accordingly. That is, if a company is registered as a transmission owner and generator owner then the cost burden would be $78,828 ($39,414 * 2 = $78,828).
Back to Context

159. We use fifty percent of the first year "number of hours per response" figure in the information collection statement for calculation under the assumption that smaller entities do not have complicated systems or will not have as many new elements on average as larger entities do.
Back to Context

160. Order No. 486, *Regulations Implementing the National Environmental Policy Act*, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986-1990 ¶ 30,783 (1987).
Back to Context

161. 18 CFR 380.4(a)(5).
Back to Context

June 21, 2012
Commissioner John R. Norris
STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. : **RM12-6-000 and RM12-7-000**
Item No.: E-4

Statement of Commissioner John R. Norris on NERC's Revised Definition for Bulk Electric System

"I'm pleased to support today's Notice of Proposed Rulemaking (NOPR) addressing the North American Electric Reliability Corporation's (NERC) new definition of the bulk electric system, along with accompanying changes to the NERC Rules of Procedure.

Certain aspects of the process that led us to today's NOPR show how the Commission and NERC can and must work together to carry out our responsibilities under section 215 of the Federal Power Act. By way of background, in Order No. 693, and later in the Order No. 743 proceedings, the Commission expressed concern that the existing definition of bulk electric system (carried over from the pre-Energy Policy Act of 2005 voluntary standards) may not encompass all of the facilities necessary for operating an interconnected electric transmission network. Order No. 743 also offered recommendations for how to address our stated concerns, but did not dictate that those particular recommendations be adopted. We allowed for alternative proposals, so long as they equally addressed our concerns.

Today's NOPR proposes to find that the proposals submitted by NERC satisfy our concerns and meet the statutory requirements for approval. This is a significant achievement for NERC and its stakeholders. I want to emphasize two aspects of how we got here that I think serve as examples of how the Commission and NERC can, working together, effectively meet reliability challenges.

First, it is important to emphasize that NERC promptly responded to the concerns expressed in Order No. 743 with the proposals before us today. While there has been criticism of the length of time it can take NERC to complete reliability standards work, NERC and the industry stakeholders involved in this effort are to be commended for their speedy and thorough response. We have done our best to provide an equally speedy and thorough reply in this NOPR, which is also important. Diligence in working through identified concerns is critical to satisfying the responsibilities entrusted to FERC and NERC, as the Electric Reliability Organization (ERO), by Congress.

Second, I would note that the proposals submitted by NERC do not conform in every way to the recommendations we offered in Order No. 743. However, the NOPR proposes to find that those aspects of the proposal that differ from our guidance are an equally efficient and effective alternative. It is important that the Commission give alternatives to our guidance fair consideration, and we have done that here.

Let me also highlight one issue in the NOPR on which we seek comment. The proposed bulk electric system definition relies on a 100 kV "bright line" threshold, along with certain expressly defined inclusions and exclusions, as a proxy for determining whether elements should be designated as part of the bulk electric system. NERC also proposed an exception process, through which individual system elements or facilities can be excluded or included in the bulk electric system.

The ultimate goal here is to ensure that all facilities impacting the reliability of the interconnected transmission network are captured within the bulk electric system rubric and subject to mandatory reliability standards. While utilizing a bright line threshold to determine what facilities and elements are within the bulk electric system has significant advantages, it can also leave out critical facilities that fall below that threshold. The September 2011 reliability events in Southern California displayed how important lower voltage, sub-100 kV facilities can be to the reliability of the broader interconnected grid in certain circumstances.

Thus, while proposing to approve the exception process, the NOPR seeks comment on how sub-100 kV facilities will be assessed for possible inclusion in the bulk electric system. The NOPR correctly emphasizes that Regional Entities, planning authorities, reliability coordinators, transmission operators, transmission planners, balancing authorities, and owners of system elements, as the entities with "on the ground" expertise of the system elements in their purview, bear primary responsibility for analyzing sub-100 kV elements and facilities and seeking to include in the bulk electric system any that are necessary for reliable operations.

These entities take their reliability obligations seriously, and I am certain they will conduct a thorough analysis of sub-100 kV elements in their local and regional areas. We also seek comment, however, on the potential roles of NERC and the Commission in assessing sub-100 kV facilities, including asking whether there are instances where the Commission should take more affirmative steps to itself designate such facilities as part of the bulk electric system. While I do not favor top down approaches to reliability matters, I also recognize that there may be rare circumstances where NERC and/or the Commission, in performing their statutory responsibilities, discover sub-100 kV elements or facilities that should be included in the bulk electric system. The Southern California outages of last year are one example.

Developing and enforcing mandatory reliability standards for the bulk power system is a huge task. I believe we will have a more sustainable mandatory reliability standards program, and ultimately a more reliable grid, if we work closely and cooperatively with NERC. We might eventually get to the same reliability goals working on our own or dictating results from the top down, but it will likely take longer and certainly be less efficient. Moreover, as I have said many times, Congress established a different paradigm in section 215 of the Federal Power Act, giving the Commission a different scope of authority and placing us in a public-private partnership with NERC. For these reasons, I am always sensitive to the Commission's appropriate place in this paradigm, and cognizant that stretching the scope of our section 215 authority or establishing adversarial processes can work against our shared reliability goals. I thus will be keenly interested in comments on the potential role of the Commission in designating facilities for inclusion in the bulk electric system."



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Part III

Department of Energy

Federal Energy Regulatory Commission

18 CFR Part 40

Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure; Proposed Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket Nos. RM12–6–000 and RM12–7–000]

Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to approve a modification to the currently-effective definition of ''bulk electric system'' developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The revised definition of ''bulk electric system'' removes language allowing for regional discretion in the currently-effective bulk electric system definition. The revised definition establishes a bright-line threshold that includes all facilities operated at or above 100 kV. The modified definition also identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of ''bulk electric system.''

The Commission also proposes to approve: (1) NERC's contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, or remove elements from, the definition of ''bulk electric system'' on a case-by-case basis; (2) NERC's proposed form entitled ''Detailed Information To Support an Exception Request'' that entities will use to support requests for exception from the ''bulk electric system'' definition; and (3) NERC's proposed implementation plan for the revised ''bulk electric system'' definition.

DATES: Comments are due September 4, 2012.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

• *Electronic Filing:* Through *http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

• *Mail/Hand Delivery:* Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,247

Issued June 22, 2012.

1. Under section 215 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) proposes to approve a modification to the currently-effective definition of ''bulk electric system'' contained in NERC's *Glossary of Terms Used in Reliability Standards* (NERC Glossary) developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. NERC submitted its petition in response to the Commission's directive in Order No. 743 that NERC develop a revised definition of ''bulk electric system'' using NERC's Reliability Standards development process.[2] The revised definition of bulk electric system:

(a) Removes the basis for regional discretion in the current bulk electric system definition;

(b) Establishes a bright-line threshold so that the ''bulk electric system'' will be facilities operated at 100 kV or higher, if they are Transmission Elements, or connected at 100 kV or higher, if they are Real Power or Reactive Power resources; and

(c) Contains specific inclusions (I1–I5) and exclusions (E1–E4) to provide clarity in the definition that the facilities described in these configurations are included in or excluded from the ''bulk electric system.''

2. The Commission also proposes to approve:

(a) NERC's contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, and remove elements from the definition of ''bulk electric system'' on a case-by-case basis;

(b) NERC's proposed form entitled ''Detailed Information to Support an Exception Request'' that entities will use to support requests for exceptions from the ''bulk electric system'' definition; and

(c) NERC's proposed implementation plan for the revised ''bulk electric system'' definition.

3. NERC's proposed revision to the definition of ''bulk electric system'' removes regional discretion and establishes a 100 kV bright-line threshold. Further, we believe that NERC's proposal offers additional clarity to the definition of bulk electric system by creating specific inclusions and exclusions within the definition, which provide granularity with regard to common types of facilities and facility configurations and whether they are part of the bulk electric system.

4. We believe that the proposed ''core'' definition, including the inclusions and the exclusions, as well as the exception process should produce consistency in identifying bulk electric system elements across the reliability regions. In addition, it appears that NERC's proposed exception process to add elements to, and remove elements from, the definition of the bulk electric system adds transparency and uniformity to the process.

5. Although it is rare that the Commission would address Rules of Procedure changes in a rulemaking docket, we will do so in this instance because of the interplay between NERC's modified bulk electric system definition and the newly developed case-specific exception process set forth in NERC's proposed Rules of Procedure change. While we propose to approve NERC's petitions, we also seek comment from NERC and interested parties on certain aspects of NERC's petitions to understand the application of the proposed ''core'' definition, including the application of the inclusions and exclusions, and the proposed exception process to ensure consistent implementation.

[1] 16 U.S.C. 824o (2006).

[2] *Revision to Electric Reliability Organization Definition of Bulk Electric System,* Order No. 743, 133 FERC ¶ 61,150, *order on reh'g,* Order No. 743–A, 134 FERC ¶ 61,210 (2011).

I. Background

A. Section 215 of the FPA

6. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[3] The Commission established a process to select and certify an ERO [4] and, subsequently, certified NERC as the ERO.[5]

B. Order No. 693

7. On March 16, 2007, in Order No. 693, pursuant to section 215(d) of the FPA, the Commission approved 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the NERC Glossary, which includes NERC's definition of bulk electric system.[6] That definition provides:

> As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.[7]

8. In approving NERC's definition of bulk electric system, the Commission stated that ''at least for an initial period, the Commission will rely on the NERC definition of bulk electric system and NERC's registration process to provide as much certainty as possible regarding the applicability to and the responsibility of specific entities to comply with the Reliability Standards.'' [8] The Commission also stated that ''[it] remains concerned about the need to address the potential for gaps in coverage of facilities.'' [9]

C. Order Nos. 743 and 743–A

9. On November 18, 2010, the Commission revisited the definition of ''bulk electric system'' in Order No. 743, which directed NERC, through NERC's Reliability Standards Development Process, to revise its definition of the term ''bulk electric system'' to ensure that the definition encompasses all facilities necessary for operating an interconnected transmission network. The Commission also directed NERC to address the Commission's technical and policy concerns. Among the concerns were inconsistency in application of the definition and a lack of oversight and exclusion of facilities from the bulk electric system that are required for the operation of the interconnected transmission network. In Order No. 743, the Commission stated that the best way to address these concerns is to eliminate the Regional Entity discretion to define bulk electric system without NERC or Commission review, maintain a bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and adopt an exemption process and criteria for removing from the bulk electric system facilities that are not necessary for operating the interconnected transmission network.[10] However, Order No. 743 did not require NERC to adopt these recommendations as the sole means to address the Commission's concerns. Instead, the Commission allowed NERC to ''propose a different solution that is as effective as, or superior to, the Commission's proposed approach in addressing the Commission's technical and other concerns so as to ensure that all necessary facilities are included within the scope of the definition.'' [11] The Commission directed NERC to file the revised definition of bulk electric system and its process to exempt facilities from inclusion in the bulk electric system within one year following the effective date of the final rule.[12]

10. In Order No. 743–A the Commission reaffirmed its determinations in Order No. 743. In addition, the Commission clarified that the issue the Commission directed NERC to rectify was the discretion the Regional Entities have under the current definition to define the bulk electric system in their regions without any oversight from the Commission or NERC.[13] The Commission also clarified that it was not the Commission's intent through its determination regarding ''impact-based methodologies'' to disrupt the NERC Rules of Procedure or the Statement of Compliance Registry Criteria (Registry Criteria).[14] Nor did the Commission intend to rule out using any form of a material impact test that can be shown to identify facilities needed for reliable operation.[15] The Commission also clarified that the 100 kV threshold was a ''first step or proxy'' for determining which facilities should be included in the bulk electric system.[16]

11. The Commission further clarified that the statement in Order No. 743, ''determining where the line between 'transmission' and 'local distribution' lies * * * should be part of the exemption process the ERO develops'' was intended to grant discretion to NERC, as the entity with technical expertise, to develop criteria to determine how to differentiate between local distribution and transmission facilities in an objective, consistent, and transparent manner.[17] The Commission stated that the ''seven factor test'' adopted in Order No. 888 could be relevant and possibly is a logical starting point for determining which facilities are local distribution for reliability purposes.[18] However, the Commission left it to NERC in the first instance to determine if and how the seven factor test should be considered in differentiating between local distribution and transmission facilities for purposes of determining whether a facility should be classified as part of the bulk electric system.[19] Order No. 743–A re-emphasized that local distribution facilities are excluded from the definition of Bulk-Power System and, therefore, must be excluded from the definition of bulk electric system.[20]

D. NERC's Petitions

12. On January 25, 2012, NERC submitted two petitions pursuant to the directives in Order No. 743: (1) NERC's proposed revision to the definition of ''bulk electric system'' which includes provisions to include and exclude

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[3] *See* 16 U.S.C. 824o(e)(3) (2006).

[4] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards,* Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g,* Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[5] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g and compliance,* 117 FERC ¶ 61,126 (2006) (certifying NERC as the ERO responsible for the development and enforcement of mandatory Reliability Standards), *aff'd sub nom. Alcoa Inc.* v. *FERC,* 564 F.3d 1342 (DC Cir. 2009).

[6] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[7] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 75 n. 47 (quoting NERC's definition of ''bulk electric system'').

[8] *Id.* P 75; *see also* Order No. 693–A, 120 FERC ¶ 61,053 at P 19 (''the Commission will continue to rely on NERC's definition of bulk electric system, with the appropriate regional differences, and the registration process until the Commission determines in future proceedings the extent of the Bulk-Power System'').

[9] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 77 (footnotes omitted).

[10] Order No. 743, 133 FERC ¶ 61,150 at P 16.

[11] *Id.*

[12] *Id.* P 113.

[13] Order No. 743–A, 134 FERC ¶ 61,210 at P 11.

[14] *Id.* P 47.

[15] *Id.*

[16] *See* Order No. 743–A, 134 FERC ¶ 61,210 at PP 40, 67, 102–103.

[17] *Id.* P 68.

[18] *Id.* P 69.

[19] *Id.* P 70.

[20] *Id.* PP 25, 58.

facilities from the ''core'' definition and (2) revisions to NERC's Rules of Procedure to add a procedure creating an exception process to classify or de-classify a facility as part of the ''bulk electric system.'' In this NOPR, we address both petitions.[21]

1. Revised Definition of Bulk Electric System

13. In Docket No. RM12–06–000, NERC filed a petition requesting Commission approval of a revised definition of ''bulk electric system'' in the NERC Glossary (NERC BES Petition). As explained below, the definition consists of a ''core'' definition and a list of facilities configurations that will be included or excluded from the ''core'' definition. NERC also requests approval of the proposed ''Detailed Information to Support an Exception Request'' form as satisfying the requirement in Order No. 743 that NERC develop ''technical criteria'' to address exception requests.[22] Finally, NERC requests Commission approval of its plan for implementation of the revised definition of ''bulk electric system.''

a. ''Core'' Definition of Bulk Electric System

14. NERC proposes the following ''core'' definition of bulk electric system:

> Unless modified by the [inclusion and exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.[23]

15. NERC states that the core definition eliminates regional discretion and establishes a clear, bright-line based on a 100 kV threshold. NERC states that the core definition places within the bulk electric system ''all Transmission Elements operated at 100 kV or above, and all Real Power and Reactive Power resources connected at 100 kV or above,'' while establishing an express exclusion for facilities used in the local distribution of electrical energy.[24] NERC states that the revised definition deletes the phrase ''[a]s defined by the Regional Reliability Organization'' that is included in the current definition, eliminating the express basis for regional discretion.[25] NERC explains that the core definition includes the 100 kV criterion as a bright-line threshold, rather than as a general guideline, by eliminating the phrase ''generally operated at'' found in the current definition.[26]

16. NERC also explains that, while the current definition includes the phrase ''associated equipment,'' and the revised definition does not, ''associated equipment'' is included in the revised definition by the use of the term ''Transmission Elements'' included in the revised core definition. NERC states that the NERC Glossary defines ''Transmission'' as ''[a]n interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems;'' [27] and defines ''Elements'' as, ''[a]ny electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.'' [28]

17. NERC states that the revised definition satisfies the Commission's directives and addresses the technical and policy concerns expressed in Order Nos. 743 and 743–A. According to NERC, the explicit basis of authority for Regional Entity discretion in the current definition is eliminated. In addition, NERC states that the core definition establishes specific threshold criteria rather than general guidelines of facilities operated or connected at or above 100 kV. Further, NERC states that the core definition in combination with the specific inclusions and exclusions provides a detailed set of criteria that can be applied on a uniform, consistent basis across all regions, eliminates ambiguity, and eliminates the potential for discretion and subjectivity in determining what facilities are part of or not part of the bulk electric system.

b. Inclusions and Exclusions to the Definition of Bulk Electric System

18. NERC states that, as part of the revised definition, NERC developed inclusions and exclusions to eliminate discretion in application of the revised ''bulk electric system'' definition. NERC states that the inclusions address five specific facilities configurations to provide clarity that the facilities described in these configurations are included in the bulk electric system (unless the facilities are excluded based on one of the specific exclusions).[29] The five inclusions are:

> Inclusions:
>
> I1—Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3.
>
> I2—Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.
>
> I3—Blackstart Resources identified in the Transmission Operator's restoration plan.
>
> I4—Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.
>
> I5—Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

19. NERC explains that the facilities described in inclusions I1, I2, I4, and I5 are each operated or connected at or above 100 kV. NERC states that inclusion I3 encompasses blackstart resources identified in a transmission operator's restoration plan, which are necessary for the operation of the interconnection transmission system and should be included in the bulk electric system regardless of their size (MVA) or the voltage at which they are connected. NERC states that the inclusions will further reduce the potential for the exercise of discretion and subjectivity to exclude such configurations from the bulk electric system.

20. According to NERC, inclusion I1 includes transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under exclusion E1 or E3 (discussed later). NERC states that

[21] ''Exclusion'' refers to configurations of elements NERC has identified within the revised definition of bulk electric system that should not be included in the bulk electric system. In contrast, an ''exception'' refers to an element that falls within the bulk electric system definition but is found not to be necessary for the operation of the grid through the proposed exception process, or an element that an element that falls outside of the bulk electric system definition but is found through the exception process should be part of the bulk electric system. Thus, an ''exception'' may result in adding elements to, or removing elements from, the definition of bulk electric system. Also, NERC uses the term ''exception'' rather than the term ''exemption'' used in Order No. 743. *See* Order No. 743, 133 FERC ¶ 61,150 at P 115.

[22] The Detailed Information to Support an Exception Request is part of the exception process even though NERC filed it as part of the BES Petition. *See* NERC BES Petition at 25–26. Thus, the Commission will address the Detailed Information in the context of the NERC BES Petition rather than in the section of this NOPR addressing the exception procedure petition.

[23] *Id.* at 13.

[24] *Id.* at 16. The current definition and Order No. 743 use the term ''facility.'' NERC proposes to use the term ''Element'' as used in the NERC Glossary.

[25] *Id.* at 15.

[26] *Id.* at 16.

[27] *Id.* at 15 n. 13.

[28] *Id.*

[29] *Id.* at 16.

transformers operating at 100 kV or higher are part of the existing definition, but since transformers have windings operating at different voltages, and multiple windings in some circumstances, clarification was required to explicitly identify which transformers are included in the bulk electric system.

21. Inclusion I2 addresses generating resources with a gross individual nameplate rating greater than 20 MVA or a gross plant/facility aggregate nameplate rating greater than 75 MVA. According to NERC, inclusion I2 includes in the bulk electric system the generator terminals through the high-side of the step-up transformers connected at a voltage of 100 kV or above. NERC states that this inclusion mirrors the text of the NERC Registry Criteria (Appendix 5B of the NERC Rules of Procedure) for generating units.[30] NERC states that a ''basic tenet that was followed in developing the [revised definition] was to avoid changes to Registrations * * * if such changes are not technically required for the [revised definition] to be complete.'' [31]

22. As noted above, inclusion I3 includes blackstart resources identified in the transmission operator's restoration plan in the bulk electric system.

23. Inclusion I4 includes dispersed power producing resources with gross aggregate capacity nameplate rating greater than 75 MVA which utilize a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above. NERC states that this inclusion was added to accommodate the effects of variable generation on the bulk electric system.

24. Inclusion I5 addresses static or dynamic devices (excluding generators) dedicated to supplying or absorbing reactive power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in inclusion I1. NERC states that this inclusion is the technical equivalent of inclusion I2 for reactive power devices.

25. NERC states that the four exclusions identify facilities configurations that should not be included in the bulk electric system.[32] Generally, the exclusions address radial systems, behind-the-meter generation and local networks that distribute power to load. The four exclusions are:

Exclusions:

E1—Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

(a) Only serves Load. Or,

(b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

(c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note—A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

E2—A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) The net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

E3—Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk-power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk-power transfer across the interconnected system. The LN is characterized by all of the following:

(a) *Limits on connected generation:* The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

(b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

(c) *Not part of a Flowgate or transfer path:* The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

E4—Reactive Power devices owned and operated by the retail customer solely for its own use.

Note—Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

26. Exclusion E1 provides detailed criteria for determining which facilities are properly excluded from the bulk electric system as radial facilities, which NERC states is intended to enhance the clarity of the radial facilities exclusion. NERC explains that criteria ''b'' and ''c'' of exclusion E1 identify the maximum amount of generation allowed on the radial facility while still qualifying for the radial facilities exclusion (aggregate capacity less than or equal to 75 MVA). NERC indicates that this exclusion addresses the circumstances of small utilities (including municipal utilities and cooperatives). According to NERC, ''the maximum amount of generation allowed on the radial facility is sufficient to allow small utilities to continue to provide service options that support reliability of the interconnected transmission network, while not operating to exclude larger generators from the [bulk electric system].''[33] Further, NERC states, that the maximum amount of generation allowed on the radial facility per criteria ''b'' and ''c'' is consistent with the aggregate capacity threshold presently provided in the Registry Criteria for registration as a generator owner or generator operator (75 MVA gross nameplate rating).

27. With respect to the ''normally open switch'' note at the end of exclusion E1, NERC explains that this note is intended to address a common network configuration ''in which two separate sets of facilities that, each standing alone, would be recognized as radial systems and not included in the bulk electric system are connected by a 'normally open switch'—i.e., a switch that is set to the open position—for reliability purposes.'' [34] NERC states that a switch in this configuration is installed by entities to provide greater reliability to their end-use customers. According to NERC, scheduled maintenance activities on a radial line, or an unscheduled outage impacting the single point of supply to the radial line, could cause the disruption of power supply to the end-use customers served by the line, unless the entity has the ability to temporarily switch to another feed.[35] NERC states that the entity's operating procedures dictate how and when to operate such a normally open switch. NERC explains that an entity does not arbitrarily close the normally open switch placed in this configuration. Rather, the entity closes the ''normally open'' switch to maintain reliability of service to its end-use customers served from the affected radial line. NERC believes that facilities that otherwise meet the criteria for the

[30] *Id.* at 17 (citing section III.c.1 and III.c.2 of Appendix 5B of the Rules of Procedure).

[31] *Id.* at 17.

[32] *Id.* at 18.

[33] *Id.* at 19.

[34] *Id.*

[35] As explained below, the switch, though normally open, could be closed in such circumstances to allow the affected radial line to serve load by relying on another line through the closed switch.

radial system exclusion in exclusion E1 should not be included in the bulk electric system solely because the entity maintains a switch of this type, which is normally open, between sets of radial facilities. NERC states that for a set of radial facilities that are connected by a switch to qualify for the radial exclusion under exclusion E1, the switch must be identified as ''normally open'' on ''source documents such as, prints or one-line diagrams and must in fact be normally set in the open position.'' [36]

28. NERC states that subjecting two sets of radial facilities that are normally unconnected to each other because the switch between them is open to the Reliability Standards during the limited time periods when the switch is closed for maintenance-related or outage-related circumstances would be fundamentally impractical and unworkable (from both the entity's perspective and the ERO's perspective).[37] NERC explains that this note will prevent numerous exception requests because this configuration is common.

29. According to NERC, exclusion E2 excludes a generating unit or units on the customer's side of the retail meter that serves all or part of the retail load subject to two conditions. First, the net capacity provided by the generating unit does not exceed 75 MVA. Second, standby, back-up, and maintenance power services are provided to the generating unit or the retail load by a balancing authority, or pursuant to a binding obligation with a generator owner or generator operator, or under terms approved by the applicable regulatory authority. NERC states that these generating units are not necessary for the operation of the interconnected transmission network and, therefore, do not need to be included in the definition because they serve a single retail load, provide a limited amount of capacity to the bulk electric system, and are fully backed up by other resources.[38]

30. NERC explains that exclusion E3, the ''local network'' exclusion, encompasses local networks of transmission elements operated at between 100 kV and 300 kV ''that distribute power to load rather than transfer bulk power across the interconnected system.'' [39] NERC explains that ''[t]he purpose of local networks is to provide local distribution service, not to provide transfer capacity for the interconnected transmission network.'' [40] According to NERC, a network that supports distribution and does not accommodate bulk-power transfers across the interconnected system should not be included in the bulk electric system. NERC also states that the ''detailed conditions established in exclusion E3 are sufficient to ensure that such qualifying local networks are being used exclusively for local distribution purposes.'' [41] NERC adds that facilities used for the local distribution of electric energy are expressly excluded from the bulk electric system by the core definition as well as by the local network exclusion.

31. Exclusion E4 encompasses reactive power devices owned and operated by a retail customer solely for its own use. NERC explains that exclusion E4 is the technical equivalent of exclusion E2 for reactive power devices.

c. Detailed Information To Support an Exception Request

32. In Order No. 743, the Commission directed NERC to develop a set of technical criteria to use in addressing requests for exceptions to the definition of the bulk electric system.[42] NERC states that it would be ''more feasible to develop a common set of data and information that could be used by the Regional Entities and NERC to evaluate exception requests'' than to develop the detailed criteria.[43] The Detailed Information Form contains the common set of data that entities seeking an exception must submit with every exception request. NERC indicates that the Detailed Information Form represents an equal and effective alternative approach to developing a substantive set of technical criteria for granting and rejecting exception requests required in Order No. 743.[44] Thus, NERC asks the Commission to approve the Detailed Information Form as satisfying the Commission's technical concerns expressed in Order No. 743 with respect to the need for criteria to approve or disapprove exception requests.

33. The Detailed Information Form specifies that all exception requests include a one-line breaker diagram identifying the element for which the exception is requested and data and studies to support the submittal. NERC states that the studies should be based on an Interconnection-wide base case to reflect the electrical characteristics and system topology. The studies should clearly document all assumptions used, address key performance measures of bulk electric system reliability through steady state power flow, and contain a transient stability analysis as necessary to support the entity's request. NERC notes that the applicant remains responsible for providing sufficient information and argument to justify the exception request.[45]

34. According to NERC, the information that an applicant may submit in support of an exception request is not limited to the Detailed Information Form. Rather, an applicant is expected to submit all relevant data, studies and other information that supports the exception request. Further, the Regional Entity and NERC may ask an applicant to provide other data and studies in addition to the Detailed Information Form.[46]

d. Proposed Implementation Plan for Revised Definition of ''Bulk Electric System''

35. NERC requests that the revised definition ''should be effective on the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, the revised [bulk electric system definition] should go into effect on the first day of the second calendar quarter after its adoption by the NERC Board.[47] The existing definition would be retired at midnight of the day immediately prior to the effective date of the revised definition in the jurisdiction in which the revised definition is becoming effective. NERC states that the proposed effective date is appropriate to provide a reasonable time between the date of regulatory approval, which is not under the control of NERC or the industry, and the effective date of the revised BES definition.[48]

36. NERC also requests that compliance obligations for all elements newly-identified to be included in the bulk electric system based on the revised definition should begin twenty-four months after the applicable effective date of the revised definition. NERC notes that the Commission stated

[36] *Id.* at 20 n. 26. NERC provides other examples of source documents such as diagrams displayed within an energy management system or a SCADA system.

[37] *Id.* at 20–21.

[38] *Id.* at 21.

[39] *Id.* at 22.

[40] *Id.*

[41] *Id.* at 23. *See also id.* at Exh. G (Technical Justification Paper for ''Local Network Exclusion'') at 2 (LN Technical Paper).

[42] Order No. 743, 133 FERC ¶ 61,150 at P 115 (stating ''NERC should develop an exemption process that includes clear, objective, transparent and uniformly applicable criteria for the exemption of facilities that are not necessary for operating the grid.'').

[43] NERC BES Petition at 26.

[44] *Id.* at 26, 32 (citing Order No. 743, 133 FERC ¶ 61,150 at P 115).

[45] *Id.* at 30.

[46] *Id.* at 27 n.32.

[47] *Id.* at 34.

[48] *Id.*

in Order Nos. 743 and 743–A that the transition period should not exceed 18 months from the date of Commission approval of the revised definition, unless the Commission approved a longer transition period based on specific justification. NERC believes that a ''somewhat longer transition period'' is necessary in light of the actions that will need to be completed in connection with the revised definition. NERC notes that in the United States, the proposed transition period will be between a minimum of approximately twenty-seven months and a maximum of thirty months from the date of Commission approval, depending on the date of Commission approval.'' [49] NERC states that sufficient time is needed: (1) To implement transition plans to accommodate any changes resulting from the revised definition; (2) for entities to file for exceptions, and for the Regional Entities and NERC to process those exceptions to a final determination, pursuant to the proposed exception process; and (3) for owners of facilities and elements that are newly-included in the bulk electric system based on the definition to train their personnel on compliance with the Reliability Standards applicable to the newly-included facilities and elements, so that these entities can achieve compliance with applicable Reliability Standards by the end of the transition period.

2. NERC Petition for Approval of Revisions to Rules of Procedure To Adopt a Bulk Electric System Exception Process

a. Changes to NERC's Rules of Procedure

37. In Docket No. RM12–7–000, NERC filed proposed revisions to its Rules of Procedure for the purpose of adopting a procedure for entities to obtain an exception from the definition of bulk electric system (NERC ROP Petition). NERC states that the proposed exception process, which is a mechanism to add elements to, and remove elements from, the bulk electric system, addresses the concerns raised in Order No. 743 with respect to the current processes for determining what facilities are part of the bulk electric system and what facilities are not.[50] NERC also states that the exception process ''provides for decisions to approve or disapprove exception requests to be made by NERC, rather than by the Regional Entities, thereby eliminating the potential for inconsistency and subjectivity that the Commission was concerned [about, which] was created by having decisions as to what facilities are included in or excluded from the BES made at the Regional Entity level.'' [51] NERC proposes to add section 509 (Exceptions to the Definition of the Bulk Electric System), section 1703 (Challenges to NERC Determinations of BES Exception Requests) and Appendix 5C (Procedure for Requesting and Receiving an Exception to the NERC Definition of Bulk Electric System) to NERC's Rules of Procedure. The NERC ROP Petition also includes proposed conforming revisions to other Rules of Procedure, including revisions to sections 302.2, 501.1.4.4, 804, 1102.2, and 1701 and appendices 2, 3D, 4B, 5B, 6, and 8, which NERC states are necessary in light of the revised definition and the exception process.

Section 509 of the Rules of Procedure

38. NERC states that proposed section 509 establishes a procedure, which is contained in a new Appendix 5C to the Rules of Procedure, for an entity to request that an element that falls outside of the definition of the bulk electric system be treated as part of the bulk electric system and for an entity to request that an element that falls within the definition of the bulk electric system not be treated as part of the bulk electric system:

> An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside the definition of the Bulk Electric System should be considered a part of the Bulk Electric System.[52]

NERC explains that the exception process is ''not intended to be used to resolve ambiguous situations,'' i.e. the exception process is only available after an initial determination has been made regarding whether an element is part of or not part of the bulk electric system through the application of the definition to the element.[53]

Appendix 5C to the Rules of Procedure

39. NERC explains that proposed Appendix 5C sets forth the detailed procedures for obtaining an exception to include an element in, or remove an element from, the bulk electric system.[54] The exception process involves three steps.[55] First, an entity applies the bulk electric system definition to a transmission element to determine its status. If the entity believes that the element, contrary to its characterization based on the definition, should either be treated, or not be treated, as part of the bulk electric system, the entity may submit an exception request to the Regional Entity in which the element is located. Second, the Regional Entity screens the request to determine whether the application meets the filing criteria and, if so, reviews the application and makes a recommendation to NERC whether to approve or deny the request. Third, the NERC President decides whether to approve or deny the exception request after considering the opinion provided by a NERC review panel.[56] If the entity does not agree with the NERC President's decision, it may appeal the decision to the NERC Board of Trustees Compliance Committee (Compliance Committee) who is the final arbiter of the request.

40. According to NERC, if the Regional Entity denies the exception request based on the initial screening but the applicant believes the exception request is proper and complete, the applicant may appeal the rejection directly to NERC.

41. NERC explains that the proposed exception process will allow NERC to provide consistent determinations on exception requests submitted from different regions involving the same or similar facts and circumstances, and will allow NERC to take into account the aggregate impact on the bulk electric system of approving or disapproving all of the exception requests. Finally, the exception process includes provisions for reporting information that may alter the status of an approved exception, verifying whether an exception continues to be warranted, and revoking an exception that is no longer warranted.

42. The proposed exception process includes provisions for obtaining exceptions both for inclusion in and exclusion from the bulk electric system. NERC identifies the entities that are eligible to submit exception requests. Specifically, the owner of an element may submit a request to include the element in, or remove it from, the bulk

[49] *Id.* at 35.

[50] NERC ROP Petition at 4.

[51] *Id.* (footnote omitted).

[52] *Id.* at 10.

[53] *Id.* at 10–11.

[54] *Id.* at 11. *See* also section D.1.c above.

[55] *Id.* at 13–14.

[56] The panel will have at least three members. NERC ROP Petition at 14.

electric system.[57] A Regional Entity, planning authority, reliability coordinator, transmission operator, transmission planner, or balancing authority that has (or will have upon inclusion in the bulk electric system) the elements covered by an exception request within its scope of responsibility may submit an exception request for the inclusion in the bulk electric system of an element or elements owned by a registered entity. NERC states that only a Regional Entity may submit an exception request for the inclusion in the bulk electric system of an element owned by an owner that is not a registered entity.

43. Finally, NERC states that an exception request will be subject to review to verify continuing justification for the exception.[58] According to NERC, the proposed exception process requires an entity to notify the Regional Entity and NERC within 90 days after learning of any change of condition which would affect the basis for approving the exception request. NERC will then review the information and determine whether to direct the Regional Entity to perform a substantive review to verify continuing justification and issue a recommendation to NERC.[59] NERC also states that an entity must certify every 36 months to the appropriate Regional Entity that the basis for the exception request remains valid. In addition, the proposed exception process states that if the Regional Entity obtains information through means other than the submitting entity that indicates an exception may no longer be warranted, the Regional Entity must provide NERC with the information. NERC will review the information and determine whether to direct the Regional Entity to perform a substantive review to verify continuing justification and issue a recommendation to NERC.[60]

44. NERC states that the exception process establishes a process that (1) Balances the need for effective and efficient administration with due process and clarity of expectations; (2) promotes consistency in determinations and eliminates Regional discretion by having all decisions on Exception Requests made at NERC; (3) provides for involvement of persons with applicable technical expertise in making decisions on ception Requests; and (4) should alleviate concerns about a ''one-size-fits-all'' approach.[61]

Section 1703 of the Rules of Procedure

45. NERC has also proposed to modify its Rules of Procedure to add a procedure for an entity to challenge the NERC decision on an exception request. The entity must file the challenge with the Compliance Committee within 30 days of the date of the NERC decision. The Compliance Committee must issue its decision within 90 days after the submission of the challenge, which the Compliance Committee may extend. NERC states that the Compliance Committee decision will be the final NERC decision on the exception request. In addition, the entity may appeal the final NERC decision to the Commission within 30 days following the date of the Compliance Committee's decision, or within such time period as the Commission's legal authority permits.

b. NERC's List of Facilities Granted Exceptions

46. In Order No. 743, the Commission stated that NERC should maintain a list of exempted facilities that can be made available to the Commission upon request.[62] NERC states that the proposed exception process does not include provisions for NERC to maintain a list of facilities that have received exceptions, as requested in Order No. 743, as this is an internal administrative matter for NERC to implement that does not need to be embedded in the Rules of Procedure.[63] NERC states it will develop a specific internal plan and procedures for maintaining a list of facilities for which exceptions have been granted.

47. NERC also notes that Regional Entities will maintain lists of elements within their regions for which exceptions have been granted, in order to monitor compliance with the requirement to submit periodic certifications pursuant to section 11.3 of Appendix 5C.[64]

II. Discussion

48. Pursuant to section 215(d) of the FPA we propose to approve NERC's revised definition of bulk electric system, including the specific inclusions and exclusions set forth in the definition, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed below, we believe that NERC's proposal satisfies the directives of Order No. 743 to develop modifications to the currently-effective definition of bulk electric system to ensure that the definition encompasses all facilities necessary for operating an interconnected transmission network and remove the Regional Entity discretion that currently allows for regional variations without review or oversight. We also believe NERC's proposed definition satisfies the Commission's technical concerns in Order No. 743 through the use of a bright-line 100 kV threshold, with specific inclusions and exclusions within the definition, for identifying bulk electric system elements and the establishment of an exception process for facilities that are not necessary for operating the interconnected transmission network. Further, we believe NERC's proposed definition improves clarity and transparency. Below, we discuss the proposed ''core'' bulk electric system definition as well as each bright-line inclusion and exclusion of the proposed definition.

49. While proposing to approve NERC's modified definition, we also seek additional explanation and comments regarding potential applications of the ''core'' definition, as well as the inclusions and exclusions. We believe that a common understanding of the proposed bulk electric system definition (1) promotes consistent application of the definition in identifying bulk electric system elements and facilities and (2) provides up-front clarity so as to minimize the need for future clarifications either formally through NERC's standards clarification process or case-specific in a compliance setting. Thus, we seek comment from NERC and other interested persons regarding the scenarios and applications of the NERC proposal, discussed below. Although we propose to approve the definition in this rulemaking, the responses to our questions are also intended to guide the Commission as to whether other action may be necessary, for example, directing NERC to develop a further modification to the core definition, inclusions or exclusions pursuant to section 215(d)(5) of the FPA.

50. Further, pursuant to section 215(f) of the FPA, we propose to approve the revisions to the NERC Rules of Procedure that establish an exception process to determine case-specific exceptions to the bulk electric system definition. NERC's proposal meets the section 215(f) standard of review for changes to the Rules of Procedure. The

[57] Section 5C of NERC's Rules of Procedure defines ''owner'' as ''the owner(s) of an [e]lement or [e]lements that is or may be determined to be part of the [bulk electric system] as a result of either the application of the [bulk electric system] [d]efinition or an [e]xception, or another entity, such as an operator, authorized to act on behalf of the owner of the [e]lement or [e]lements in the context of an [e]xception [r]equest.''

[58] *Id.* at 34 and Att. 1 at 17.

[59] *Id.* at 34–35 and Att. 1 at 17.

[60] *Id.* at 35 and Att. 1 at 17.

[61] *Id.* at 17.

[62] Order No. 743, 133 FERC ¶ 61,150 at P 117.

[63] NERC ROP Petition at 49.

[64] *Id.*

Detailed Information Form in the proposed rules identifies ''base-line'' information and data that any applicant must submit. Further, after Regional Entity input, NERC makes the final decision on whether to grant an exception request, which better assures consistency of decisions across all regions.

51. In Order No. 743, the Commission stated that NERC should maintain a list of facilities included or excluded from the bulk electric system pursuant to the exception process.[65] NERC indicates that, while it plans to maintain such a list, maintaining the list is an internal NERC function and, thus, not included in NERC's proposed Rules of Procedure. To understand how NERC intends to comply with the directive from Order No. 743, we propose to require that NERC submit a compliance filing detailing its internal process for tracking exception requests.

52. Below, the Commission discusses (A) the ''core'' bulk electric system definition; (B) proposed inclusions and exclusions in the definition; (C) the case-specific exception process; (D) the Detailed Information Form; and (E) NERC's implementation plan.

A. The Commission Proposes To Approve the Core Definition of Bulk Electric System

53. The bulk electric system ''core'' definition developed by NERC states as follows:

> Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

54. In Order No. 743, the Commission found that ''the current definition of bulk electric system is insufficient to ensure that all facilities necessary for operating an interconnected electric energy transmission network are included under the 'bulk electric system' rubric.'' [66] The Commission also stated that the ''aim'' of the final rule was to ''eliminate inconsistencies across regions, eliminate the ambiguity created by the current discretion in NERC's definition of bulk electric system, provide a backstop review to ensure that any variations do not compromise reliability, and ensure that facilities that could significantly affect reliability are subject to mandatory rules.'' [67] The Commission stated that the one way to accomplish these goals is to eliminate the regional discretion in the current definition, and maintain the bright-line threshold that includes all facilities operated at or above 100 kV and establish an exception process and criteria for excluding facilities that are not necessary for the operation of the interconnected transmission network.[68]

55. It appears that NERC's proposal satisfies the objectives set forth in Order No. 743. The ''core'' definition, quoted above, establishes the fundamental threshold for inclusion of facilities in the bulk electric system as those that are operated at 100 kV or higher, if they are transmission elements, or are connected at 100 kV or higher, if they are real power or reactive power resources. The core definition also establishes a 100 kV criterion as a bright-line threshold, rather than as a general guideline as in the current definition, i.e., the phrase ''generally operated at'' in the current definition is eliminated. As NERC explains, the core definition also continues to capture equipment associated with the facilities included in the bulk electric system.[69]

56. Further, consistent with Order No. 743, NERC's proposed ''bulk electric system'' definition eliminates the phrase ''as defined by the Regional Reliability Organization * * *.'' As a result, NERC's proposed definition will apply nation-wide. Thus, we believe NERC's proposal adequately addresses the concerns articulated in Order No. 743 regarding unfettered regional discretion and the need for a consistent approach satisfies the concerns regarding the elimination of inconsistencies across regions. The Commission seeks comment on whether the revised definition adequately eliminates subjectivity and regional variation as required in Order No. 743.[70]

57. Below, we seek comment regarding the exclusion of facilities used in local distribution.

Local Distribution

58. In Order No. 743, the Commission acknowledged that ''Congress has specifically exempted 'facilities used in the local distribution of electric energy' '' from the Bulk-Power System definition and that, because such facilities are exempted from the Bulk-Power System, they also are excluded from the bulk electric system.[71] The Commission also stated that, although local distribution facilities are excluded from the definition, it still is necessary to determine which facilities are local distribution, and which are transmission.[72] As the Commission stated in order No. 743–A, ''[w]hether facilities are used in local distribution will in certain instances raise a question of fact, which the Commission has jurisdiction to determine.'' In Order No. 743, the Commission also recognized that NERC would need to establish whether a particular facility is local distribution or transmission, and directed NERC to develop a means, subject to Commission approval, to make such a determination.[73] In Order No. 743–A the Commission clarified that

> the statement in Order No. 743, ''determining where the line between 'transmission' and 'local distribution' lies * * * should be part of the exemption process the ERO develops'' was intended to grant discretion to the ERO, as the entity with technical expertise, to develop criteria to determine how to differentiate between local distribution and transmission facilities in an objective, consistent, and transparent manner. * * * Once NERC develops and submits its proposal to the Commission, the Commission will, as part of its evaluation of the proposal, determine whether the process developed adequately differentiates between local distribution and transmission.
>
> We agree * * * that the Seven Factor Test could be relevant and possibly is a logical starting point for determining which facilities are local distribution for reliability purposes, while also allowing NERC flexibility in

[65] Order No. 743, 133 FERC ¶ 61,150 at P 117.

[66] Order No. 743, 133 FERC ¶ 61,150 at P 30.

[67] *Id.* P 2.

[68] *Id.*

[69] The core definition includes all ''Transmission Elements operated at or above 100 kV.'' As NERC explains in its petition, the NERC-defined term ''Transmission'' includes the phrase ''associated equipment.'' The NERC Glossary defines ''Transmission'' as ''[a]n interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.'' Additionally, the Glossary defines ''Elements'' as ''[a]ny electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.'' We agree with NERC that while the new definition does not use the term ''associated equipment,'' the phrase is included in the definition through the defined term ''Transmission Elements.''

[70] *Id.* PP 11–12, 57. The Commission notes that nothing in the immediate rulemaking proceeding should impact the application of available transmission capability (ATC) calculations as set for in Order No. 890. *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 196, *order on reh'g*, Order No. 890– A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890–C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890–D, 129 FERC ¶ 61,126 (2009). Public utility transmission service providers (or their designate) have the obligation to comply in all respects with their Commission approved tariff. This requires that they must continue to use the applicable Reliability Standards to plan and operate both their bulk electric system and non-bulk electric system facilities included in their tariffs.

[71] Order No. 743, 133 FERC ¶ 61,150 at P 37.

[72] Order No. 743–A, 134 FERC ¶ 61,210 at P 67.

[73] Order No. 743, 133 FERC ¶ 61,150 at P 37.

applying the test or developing an alternative approach as it deems necessary.[74]

59. In addressing what constitutes local distribution, NERC explains that the second sentence in the core definition, which excludes ''facilities used in the local distribution of electric energy,'' is consistent with section 215(a)(1)(B) of the FPA and the Commission's regulations at 18 CFR 39.1 and as recognized in Order No. 743–A.'' [75] NERC states that ''the core definition * * * establish[es] an express carve out for facilities used in the local distribution of electrical energy.'' [76] NERC also states that facilities for the local distribution of electric energy are expressly excluded from the bulk electric system by the core definition as well as by the local network exclusion, exclusion E3.[77] NERC adds that, while some stakeholders suggested that the Commission's seven-factor test should be employed to determine distribution facilities, the NERC drafting team ''rejected this approach as the sole determination of distribution facilities, * * * [but] pointed out that such a test could be utilized by a Submitting Entity making an Exception Request but that other information should be supplied to support the request.'' [78]

60. The Commission seeks comment from NERC and the public regarding how the proposed definition is responsive to the Commission's directives in Order Nos. 743 and 743–A. Specifically, the Commission seeks comment on how NERC's proposal adequately differentiates between local distribution and transmission facilities in an objective, consistent, and transparent manner.[79]

B. The Commission Proposes To Approve the List of Inclusions and Exclusions in the Definition of Bulk Electric System

61. Along with the core definition, NERC's proposal provides specific inclusions and exclusions. The inclusions and exclusions provide added clarity regarding which elements are part of the bulk electric system as compared to the existing definition. For example, the inclusion of generating resources, blackstart resources and dispersed power producing resources provide additional information and granularity that assist in the identification of bulk electric system facilities or elements. However, we also have questions about how some of the inclusions and exclusions will be applied by NERC, Regional Entities and users, owners and operators of the Bulk-Power System. Through the responses to these questions we seek to better understand potential applications of the inclusions and exclusions, their effect on identifying the facilities or elements for bulk electric system reliability, and whether possible gaps exist.

1. Inclusions

a. Inclusion I1 (Transformers)

62. Inclusion I1 provides ''[t]ransformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under [the radial system or local network exclusion].'' NERC explains that:

> Transformers operating at 100 kV or higher are part of the existing definition, but since transformers have windings operating at different voltages, and multiple windings in some circumstances, clarification was required to explicitly identify which transformers are included in the BES. Inclusion I1 includes in the BES those transformers operating at 100 kV or higher on the primary winding and at least one secondary winding, so as to be in concert with the core definition.[80]

63. We believe that inclusion I1, with NERC's explanation, is a reasonable approach to identifying transformers that are appropriately included as part of the bulk electric system. However, circumstances may warrant inclusion of a particular transformer—through the proposed case-specific exception process—where a transformer is operated at 100 kV or higher on the primary winding but all secondary terminals are operated below 100 kV. The joint NERC and Commission staff report on the September 8, 2011, Arizona-Southern California blackout discusses how a 92 kV networked system experienced parallel flows from bulk electric system elements through two 230/92 kV transformers.[81] The report explains that the reliability coordinator, transmission operators and balancing authorities did not consider certain sub-100 kV facilities, including two 230/92 kV transformers as bulk electric system elements. Consequently, when contingencies occurred on the bulk electric system on September 8, 2011, the reliability coordinator, transmission operators and balancing authorities were unaware that the contingencies adversely impacted the 230/92 kV transformers or how the loss of the transformers impacted system reliability.[82] The Commission seeks comment on whether these types of transformers, i.e., those that have a terminal operated at 100 kV or above on the high side and below 100 kV on the low side should be designated as part of the bulk electric system. If answered in the affirmative, the Commission seeks further comment whether the case-by-case exception process suffices, or a generic inclusion is appropriate to address the concerns identified in Order No. 743.

b. Inclusion I2 (Generating Resources)

64. Inclusion I2 provides:

> Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.

According to NERC, this inclusion ''mirrors'' the text of the NERC *Registry Criteria* for generating units. NERC explains that the drafting team ''found no technical rationale for changing at this time from the thresholds for generating resources presently specified in the * * * *Registry Criteria.*'' [83] Further, NERC states that, to provide clarity, the revised definition specifies that the bulk electric system ''includes the generator terminals through the high-side of the step-up transformer connected at a voltage of 100 kV or above.'' [84]

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[74] Order No. 743–A, 134 FERC ¶ 61,210 at PP 68–69 (footnotes omitted).

[75] NERC BES Petition at 16.

[76] *Id.* at 22–23.

[77] NERC's LN Technical Paper, Exhibit G of NERC's Petition, provides:

> In Order 743a, the Commission made it clear that facilities that are used in the local distribution of electric energy will be excluded from the Bulk Electric System. * * * In response to this facet of the Order, in developing the BES definition, the SDT has followed this guidance. Exclusion E3 was specifically designed to capture for exclusion those high voltage non-radial facilities being used for the local distribution of energy.
>
> The exclusion characteristics in items a, b, and c * * * serve to ensure that facilities excluded under the local network exclusion (E3) are not necessary for the reliable operation of the interconnected electric transmission network and are instead used in the local distribution of energy.

Id., Ex. G, at 2.

[78] NERC BES Petition at 49.

[79] We note that an element that falls outside of the definition of bulk electric system is not necessarily local distribution.

[80] NERC BES Petition at 17.

[81] Arizona-Southern California Outages on September 8, 2011—Causes and Recommendations at 96 (September 2011 Blackout Report), *available at http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.*

[82] *Id.* at 96–97.

[83] NERC BES Petition at 17. NERC states ''A basic tenet that was followed in developing the revised BES Definition was to avoid changes to Registrations due to the revised BES Definition if such changes are not technically required for the BES Definition to be complete.'' *Id.* (citing Order No. 743–A, 134 FERC ¶ 61,210 at P 102).

[84] NERC BES Petition at 17.

65. We believe that Inclusion I2 provides useful granularity regarding the inclusion of generation resources as part of the bulk electric system. However, we seek comment regarding several aspects of inclusion I2. NERC's Registry Criteria thresholds for generators provides for the registration of ''[i]ndividual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the Bulk Power System'' or ''[g]enerating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the Bulk Power System at a common bus with total generation above 75 MVA gross nameplate rating.'' [85] We agree that proposed inclusion I2 is consistent with the individual and aggregate nameplate rating thresholds set forth in the Registry Criteria. We note, however, that the Registry Criteria and the proposed definition differ regarding the description of the connection point of the generating units and plants. While inclusion I2 specifies ''generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above,'' the Registry Criteria specifies a ''direct connection'' to the Bulk-Power System. We seek comment whether inclusion I2 will result in a material change to registration of existing generating units due to the difference in the language regarding the connection point. In addition, we seek comment if, pursuant to inclusion I2, the following circumstances are included in the bulk electric system: A generating unit, with a gross individual nameplate rating greater than 20 MVA connected through the high-side of the step-up transformer connected at a voltage of 100 kV or above *when the low side of the transformer is less than 100 kV.* How does this result differ for a generation resource with two or more step-up transformers where the last transformer in the series operates at 100 kV or above, for example, a 50 MVA generator first steps up through a 23 kV transformer on the low side and 69 kV on the high side and then immediately steps up through a second transformer at the same site with less than 100 kV on the low side and above 100 kV on the high side?

c. Inclusion I3 (Blackstart Resources Identified in the Transmission Operator's Restoration Plan)

66. Inclusion I3 identifies as part of the bulk electric system ''Blackstart Resources identified in a Transmission Operator's restoration plan.'' NERC explains that blackstart resources are ''vital'' for the reliable operation of the bulk electric system and are included ''regardless of their size (MVA) or the voltage at which they are connected.'' [86] NERC further states that including blackstart resources is consistent with the *Registry Criteria,* which provide that ''*any generator, regardless* of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan'' is eligible for registration.[87]

67. We agree with NERC that inclusion of blackstart resources in the definition is vital to reliability and is an improvement to the definition. We seek clarification whether the term ''restoration plan'' refers to the system restoration plans required in the Emergency Preparedness and Operations (EOP) Reliability Standards or included in a Commission approved tariff.[88]

68. NERC states that first posting of the revised definition included ''cranking paths'' for blackstart resources due to a concern about ''the possibility of having Blackstart Resources without a 'guaranteed' path'' to the [bulk electric system].'' [89] NERC explains that ''a number of commenters complained that this was improperly bringing distribution level Elements into the [bulk electric system], as many Cranking Paths are at the distribution level'' and ''also pointed out that this was an illusory proposition as intended Cranking Paths are not always the ones used in actual restoration.'' [90] As a result of the industry feedback, NERC deleted cranking paths from the revised definition with the understanding that the issue would be revisited in Phase 2 of the BES project. According to NERC, ''this approach would maintain status quo on this topic, consistent with Order Nos. 743 and 743–A, while providing for a full discussion and consideration of the issue in a less time constrained environment''.[91] [92] Subsequently, however, the topic of cranking paths was deleted from the scope of the Phase 2 BES project.[93] In light of the decision not to further pursue a possible revision to the bulk electric system definition pertaining to cranking paths, the Commission is concerned whether a reliability gap exists with regard to cranking paths. Cranking paths constitute a basic element of system restoration, and it is unclear whether reliability can be adequately maintained when blackstart generators are defined as part of the bulk electric system but not the transmission paths that are used to deliver the energy from blackstart generators to the integrated transmission system. We also recognize that cranking paths may implicate facilities used in local distribution. Accordingly, we seek comment on whether a reliability gap may exist with regard to cranking paths and, if so, what potential approaches are appropriate to remove the gap. We also seek comment on the appropriate role, if any, of state regulators in ensuring that energy from blackstart generation is reliably delivered through cranking paths to restart the system after an event.

d. Inclusion I4 (Dispersed Power Producing Resources)

69. Inclusion I4 identifies as part of the bulk electric system:

> Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

70. NERC explains that this inclusion is intended ''to accommodate the effects of variable generation'' on the bulk

[85] Registry Criteria, III.c.1 and c.2 (Generator Owner/Operator).

[86] NERC BES Petition at 18.

[87] *Id.* (emphasis added).

[88] Reliability Standard EOP–005–1, System Restoration Plans, requires a transmission operator to create ''a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system.''

[89] NERC BES Petition at 47. The NERC Glossary defines ''Cranking Path'' as ''[a] portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.'' *See also* the Regional Bulk Electric System Definition Coordination Group concept paper that recommends including the designated cranking paths for the blackstart resources available at *http://www.nerc.com/docs/standards/sar/Project_2010-17_Concept_Paper.pdf.*

[90] *Id.*

[91] *Id.* NERC's Project 2010–17, the ''Phase 2 BES Project.''

[92] *Id.* NERC's Project 2010–17, the ''Phase 2 BES Project.''

[93] The February 21–23, 2012 meeting notes from the Project 2010–17 Definition of Bulk Electric System Phase 2 Standard Drafting Team states that ''the SDT decided to delete the Cranking Path reference in the [Phase 2] SAR.'' The reasons for the deletion included ''that Cranking Paths reach down into distribution and thus shouldn't be included in the definition,'' and ''that this issue was debated in Phase 1 and resolution was obtained,'' and ''that Cranking Paths were only needed when an entity was in restoration mode so it wasn't needed in the definition.'' However, the same document states some commenters believe ''that Cranking Paths were only needed when an entity was in restoration * * * and * * * that this was a reason to have it in the definition.'' *See* Meeting Notes from the Project 2010–17 Definition of Bulk Electric System Phase 2 Standard Drafting Team, February 21–23, 2012, at Page 5, *available at http://www.nerc.com/docs/standards/dt/Meeting_Notes-Project_2010-17_DBES-February_21-23,_2012.pdf.*

electric system.[94] NERC further states that even though inclusion I4 could be considered subsumed in inclusion I2 (generating resources), NERC believes it is appropriate ''to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity.'' [95]

71. We believe that inclusion I4 provides useful granularity in the bulk electric system definition. To better understand the application of inclusion I4, we seek comment whether this provision includes as part of the bulk electric system the individual elements (from each energy-producing resource at the site through the collector system to the common point at a voltage of 100 kV or above) used to aggregate the capacity and any step-up transformers used to connect the system to a common point at a voltage of 100 kV or above.

e. Inclusion I5 (Static or Dynamic Reactive Power Devices)

72. Inclusion I5 identifies as part of the bulk electric system:

> Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

NERC explains that this inclusion is the technical equivalent of inclusion I2 (generating resources), for reactive power devices and points out that the existing definition is unclear as to how these devices are treated.[96] NERC states inclusion I5 provides clarity by ''providing specific criteria for Reactive Power devices, thereby further limiting subjectivity and the potential for discretion'' in the application of the revised definition.[97]

73. The Commission agrees with NERC that this inclusion adds clarity to the application of the bulk electric system definition by providing specific criteria for reactive power devices. For cases where the reactive power device is connected through a transformer designated in inclusion I1, we seek comment on whether both the reactive power device and the transmission elements connecting the reactive power device to the transformer are included as part of the bulk electric system pursuant to inclusion I5.

2. Exclusions

74. NERC states that the proposed definition identifies four facilities configurations that should not be included in the bulk electric system: (1) Radial systems, (2) behind-the-meter generating units, (3) local networks, and (4) retail customer reactive power devices.

75. We agree that the proposed definition's exclusions provide clarity and granularity. For example, the exclusion of generating units on the customer's side of the retail meter that serves all or part of the retail load (exclusion E2) and the exclusion for reactive power devices owned and operated by a retail customer for its own use (exclusion E4) provide reasonable limitations on bulk electric system elements. While we believe that the exclusions provide added clarity, we also seek comment on certain aspects of exclusions E1 and E3 to ensure a more complete understanding of their application.

a. Exclusion E1 (Radial Systems)

76. Exclusion E1 provides as follows:

> Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
>
> (a) Only serves Load. Or,
>
> (b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
>
> (c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).
>
> **Note**—A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

NERC states that radial facilities are excluded under the currently effective bulk electric system definition, and the detailed criteria in the revised definition provide enhanced clarity.[98] We seek comment on our understanding and NERC's explanation of exclusion E1 in order for the Commission to ensure application of exclusion E1 is consistent. Also, we seek comment to determine if the configurations covered by Conditions (a), (b), or (c) of exclusion E1 remove from the bulk electric system generation connected to a radial system that otherwise satisfies inclusion I2. The Commission would like to ensure that the conditions in exclusion E1 will not lead to conflicting results when applying inclusion I2 and exclusion E1.

77. As stated above, the radial exclusion applies to ''a group of contiguous *transmission* Elements that emanates from a single point of connection of 100 kV or higher. * * *'' While the term ''Elements'' includes the term generator,[99] the use of the term ''transmission'' before ''Elements'' indicates that exclusion E1 applies only to transmission elements. The phrase ''transmission Elements'' in this provision does not apply to generating resources that are bulk electric system resources pursuant to inclusion I2 (generating resources), connected to a radial line operated at 100 kV above.[100]

i. Definition of 'Radial Systems' and Condition (a)—Radials Only Serving Load

78. NERC stated that it developed exclusion E1 to provide enhanced clarity as compared to the existing definition.[101] Exclusion E1 defines the term 'radial systems' as ''a group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher.'' The Commission seeks comment on how NERC's proposal would be applied in the three scenarios described below.

79. Figure 1 below depicts facilities configurations in which all of the 230 kV and 69 kV transmission elements emanate from a single point of connection of 100 kV or higher. The Commission seeks comment on whether each of the radial systems shown in figure 1, the 230 kV elements above each transformer to the point of connection to each 230 kV line, respectively, are excluded from the bulk electric system pursuant to exclusion E1.

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[94] NERC BES Petition at 18.

[95] *Id.*

[96] *Id.*

[97] *Id.*

[98] *Id.*

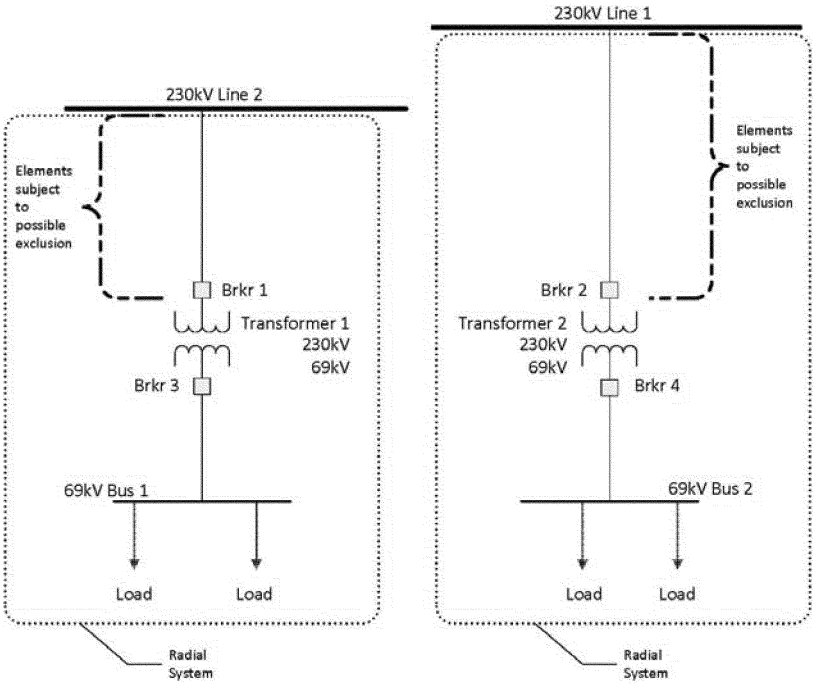
[99] ''Element'' is defined in the NERC Glossary as ''[a]ny electrical device with terminals that may be connected to other electrical devices *such as a generator,* transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.'' (emphasis added).

[100] Our understanding comports with the NERC standard drafting team's explanation in response to industry comments that generation resources connected within the radial system are not excluded pursuant to exclusion E1. *See* NERC BES Petition, Exh. D, Consideration of Comments Report, at 223 (stating that ''Exclusion E1 is an exclusion for the contiguous transmission Elements connected at or above 100 kV. Generation resources connected within the radial system are qualifiers for this exclusion.'').

[101] NERC BES Petition at 18.

Figure 1

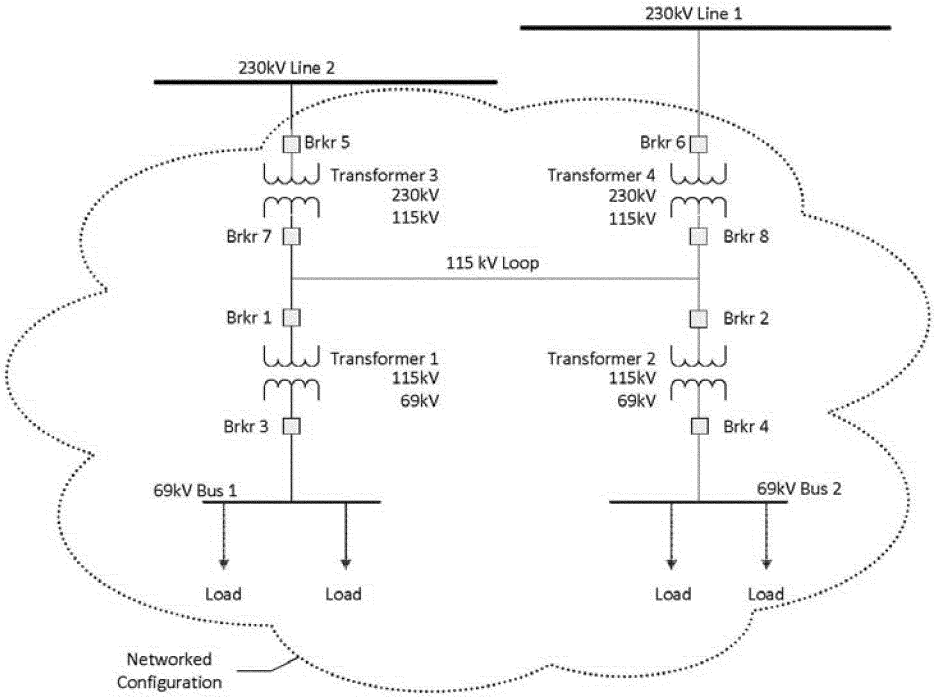
Two Radial Systems Eligible for Exclusion E1



80. Another scenario shown in figure 2 below depicts a configuration containing a 115 kV loop, with the configuration emanating from two points of connection of 100 kV or higher. We seek comment whether, in this configuration, the 115 kV and 230 kV elements above Transformers 1 and 2 to the points of connection to the two 230 kV lines would be excluded from the bulk electric system pursuant to exclusion E1. Is the configuration shown in figure 2 more appropriately analyzed pursuant to the ''local network'' exclusion E3 and, if so, what if any elements operated at or above 100 kV would be excluded pursuant to exclusion E3?

Figure 2

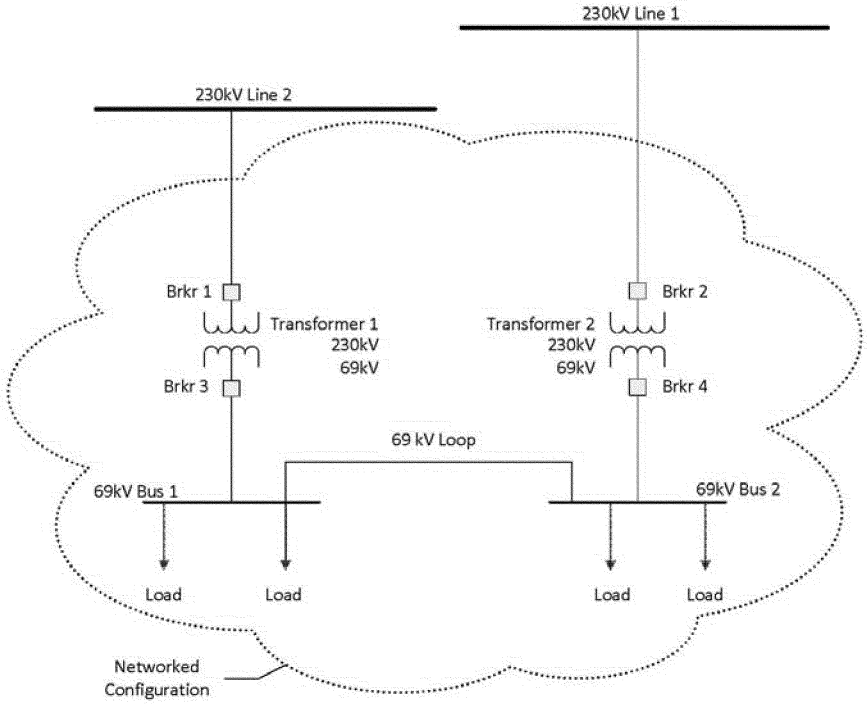
Networked Configuration w/115 kV Loop



81. The Commission agrees with NERC that 'radial systems' only serving load and emanating from a single point of connection of 100 kV or higher should be excluded from the bulk electric system. The Commission is concerned that the exclusion could allow elements operating at 100 kV or higher in a configuration that emanates from two or more points of connection to be deemed ''radial'' even though the configuration remains contiguous through elements that are operated below 100 kV. For example, figure 3 below depicts a configuration with two points of connection of 100 kV or higher that are contiguous through a 69 kV loop. We seek comment on how to evaluate the configuration in figure 3 vis-à-vis the radial system definition and whether it is appropriate to examine the elements below 100 kV to determine if the configuration meets the exclusion E1 definition for radial systems. In other words, does figure 3 depict a system emanating from two points of connection at 230 kV and, therefore, the 230 kV elements above the transformers to the points of connection to the two 230 kV lines would not be eligible for the exclusion E1 notwithstanding the connection below 100 kV?

Figure 3

Networked Configuration w/69 kV Loop



ii. Condition (b)—Radials With Limited Generation and Condition (c)—Radials With Limited Generation and Load

Condition (b) of exclusion E1 provides that a radial system is excluded if it ''[o]nly includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating).'' Proposed Condition (c) of exclusion E1, excludes radial systems ''[w]here the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).''

82. NERC states that Conditions (b) and (c) are ''intended to address the circumstances of small utilities (including municipal utilities and cooperatives).'' [102] The NERC BES Petition, including the Exhibit E record of development, does not further explain the need for, or the impact of, these proposed provisions. Accordingly, we seek comment regarding the specific circumstances that Conditions (b) and (c) are intended to address.

83. Because Condition (b) describes generation connected to a radial system with no load and Condition (c) describes generation connected to a radial system with generation and load, it appears that the power generated on these radial systems would, by design, be delivered or injected to the bulk electric system and transported to other markets. In this circumstance, it appears that a line 100 kV or above connected to a generator with a capacity 75 MVA or below would not be included in the bulk electric system. The Commission seeks comment on the appropriateness of excluding such radials.

iii. Normally Open Switches

84. Proposed exclusion E1 includes a ''note'' stating that a ''normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.'' NERC states that this note is intended to address a common network configuration in which two separate sets of facilities that, each standing alone, would be recognized as radial systems but are connected by a switch that is set to the open position for reliability purposes. [103]

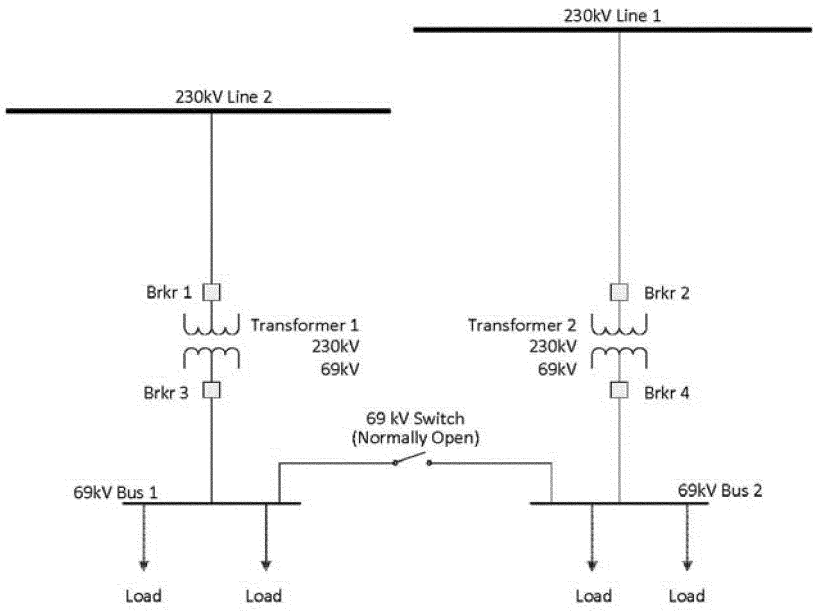
85. NERC explains that these switches are installed by entities to provide greater reliability to their end-use customers. For example, when the entity schedules maintenance activities on a radial line or an unscheduled outage occurs that impacts a single point of supply to the radial line which could cause the disruption of power supply to the end-use customers served by the line, the switch allows the entity to use another feed on the connected radial line.

86. Figure 4 below illustrates a configuration with a normally open switch.

[102] NERC BES Petition at 19.

[103] NERC BES Petition at 19–20.

Figure 4
69 kV Networked Configuration with Normally Open Switch



NERC states that ''[t]he concept that two sets of radial facilities that are normally unconnected to each other should be subject to * * * applicable Reliability Standards during the limited time periods when they are connected by the closing of the normally open switch in the maintenance-related or outage-related circumstances described above would be fundamentally impractical and unworkable (from both the entity's perspective and the ERO's perspective), and would misapprehend this very common, reliability-driven facilities configuration.'' [104]

87. NERC states that ''a normally open switch'' will be identified in documents such as prints or one-line diagrams and that ''[t]he concept and usage of the 'normally open switch' in such configuration is well understood in the electric utility industry.'' [105] We seek comment on NERC's characterization and whether the phrase ''normally open'' is subject to interpretation or misunderstanding, or whether a ''normally open'' configuration is potentially difficult to oversee. Further, we seek comment on the need of transmission operators or other functional entities to study the system impacts of the closing of a ''normally open'' switch, or to take other steps to ensure awareness of the impacts of the loop that is created by the closing of the switch if the closed loop is not included as part of the bulk electric system.

b. Exclusion E2 (Behind the Meter Generation)

88. Exclusion E2 excludes ''[a] generating unit or multiple generating units on the customer's side of the retail meter * * *.'' The Commission believes that this is an appropriate exclusion that provides additional clarity and granularity to the definition of bulk electric system.

c. Exclusion E3 (Local Networks)

89. As noted above, we believe that a common understanding of the exclusions promotes consistent application of the definition in identifying bulk electric system elements. In particular, as discussed in greater detail below, we seek comment on the following issues with respect to the application of exclusion E3: (1) Whether generation resources are excluded by this exclusion; (2) how the exclusion applies to a looped lower voltage system; (3) whether the 300 kV ceiling is appropriate for the application of the exclusion; (4) whether the prohibition for generation produced inside a local network is not transporting power to other markets outside the local network applies in both normal and emergency operating conditions.

90. Exclusion E3 defines the term local networks as:

> A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk-power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk-power transfer across the interconnected system.

Exclusion E3 also identifies three conditions that must be satisfied for the exclusion to apply: (a) Limit on connected generation to 75 MVA aggregate capacity of non-retail generation (gross nameplate rating); (b) power flows only into the local network and does not transfer through the 'local network'; and (c) the local network is not part of a flowgate or transfer path.

91. NERC states the design and operation of local networks is such that at the point of connection with the interconnected transmission network is similar to that of a radial facility, in particular that power always flows in a direction from the interconnected transmission network into the local network.[106] Further, according to NERC, ''[l]ocal networks provide local electrical distribution service and are not planned, designed or operated to benefit or support the balance of the interconnected transmission network.'' [107]

92. Similar to our discussion of the definition of 'radial systems' in

[104] *Id.* at 20–21.
[105] *Id.* at 19.
[106] NERC BES Petition at 22.
[107] *Id.*

exclusion E1, the exclusion E3 local network exclusion applies to transmission Elements, but does not apply to generation resources connected to a local network that otherwise satisfy inclusion I2.

93. NERC states in the LN Technical Paper, that ''Exclusion E3 was specifically designed to capture for exclusion those high voltage non-radial facilities being used for the local distribution of energy.'' [108] The paper further provides:

> Their [local network] design and operation is such that at the point of connection with the interconnected electric transmission network, their effect on that network is similar to that of a radial facility, particularly in that flow always moves in a direction that is from the BES into the facility. Any distribution of parallel flows into the local network from the BES, as governed by the fundamentals of parallel electric circuits, is negligible, and, more importantly, is overcome by the Load served by the local network, thereby ensuring that the net actual power flow direction will always be into the local network at all interface points. The presence of a local network is not for the operability of the interconnected electric transmission network; neither will the local network's separation or retirement diminish the reliability of the interconnected electric transmission network.'' [109]

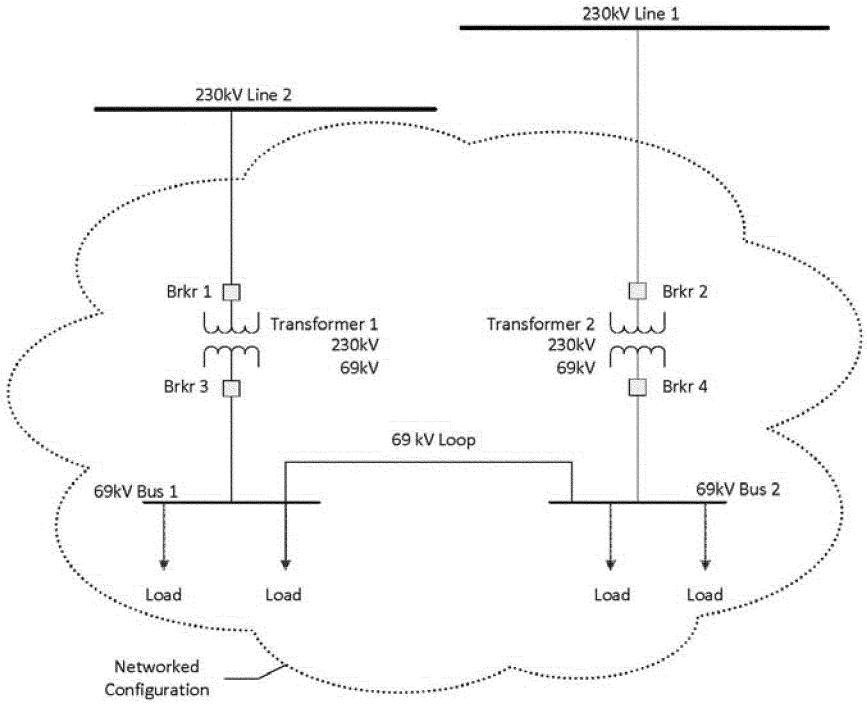
94. We seek further explanation and comment on the statement above that ''neither will the local network's separation or retirement diminish the reliability of the interconnected electric transmission network.'' While a radial facility emanates from one point of connection to the interconnected transmission network, a local network by definition has multiple points of connection to the interconnected transmission network. Thus, regarding a local network, a contingency situation may arise where one of the multiple connections to the interconnected transmission network separates, while other local network connections maintain connectivity with the bulk electric system. We seek comments to better understand how an entity with a candidate local network would analyze such contingencies to determine potential impacts to the reliable operation of the interconnected transmission network.

i. Contiguous Transmission Elements and the 100 kV Lower Limit/300 kV Cap

95. As stated above, exclusion E3 defines local networks as ''[a] group of *contiguous* transmission Elements *operated at or above 100 kV but less than 300 kV* that distribute power to Load rather than transfer bulk-power across the interconnected system.'' While the local network exclusion applies to contiguous transmission elements operating at a minimum of 100 kV, it is unclear how the exclusion applies to a looped lower voltage system. For example, figure 5 depicts a 69 kV looped system emanating from two points of connection at 100 kV or higher.

Figure 5

Networked Configuration w/69 kV Loop



The configuration in figure 5 depicts a group of elements that are contiguous through a 69 kV loop. We seek comment whether the configuration in figure 5 qualifies as a local network and, in particular, whether the configuration satisfies the condition that a local network consists of ''a group of *contiguous* transmission Elements *operated at or above 100 kV* * * *.''

96. NERC states the selection of a 300 kV cap for the applicability of an

[108] NERC BES Petition, Exhibit G at 2.

[109] *Id.*

exclusion for a local network was based upon recent NERC standards development work in Project 2006–02 ''Assess Transmission Future Needs and Develop Transmission Plans'' which sets a voltage level of 300 kV to differentiate extra high voltage (EHV) facilities from high voltage facilities acting as a threshold to distinguish between expected system performance criteria.[110] NERC states that it seeks to establish consistency in the limitations placed on the exclusion applicability for local network facilities, and has therefore adopted this 300 kV level to ensure that EHV facilities are not subject to this exclusion.[111] NERC provides a ''realistic example of the electrical interaction between a typical local network and the [bulk electric system]'' in the LN Technical Paper.[112] The example depicted in Appendix 1 of the Technical Paper shows a local network operating at 115 kV. The NERC Technical Paper does not provide examples of a local network operating within the 200 to 300 kV range, for example showing 230 kV facilities operating in a local network. We are concerned whether the 300 kV ceiling is appropriate and reflects actual system configurations that serve local distribution, the stated purpose of the local network exclusion.[113] Accordingly, we seek comment whether (and why or why not) the 300 kV ceiling is appropriate for the application of exclusion E3 and requests examples of systems between 200 and 300 kV that would qualify for this exclusion.[114]

ii. Criterion (a)—Limits on Connected Generation

97. Exclusion E3 criterion (a) provides that the local network and its underlying elements do not include the blackstart resources identified in inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA gross nameplate rating. In addition, criterion (a) does not limit the amount of generation besides ''non-retail generation'' connected to the local network. The Commission agrees with NERC that ''local networks'' do not include blackstart resources and agrees with the limits on the connected generation imposed by this exclusion.

iii. Criterion (b)—Power Flows Only Into the Local Network

98. Exclusion E3 criterion (b) specifies that to be eligible for the exclusion, power can only flow into the local network and the local network does not transfer energy originating outside the local network for delivery through the local network. Thus, it appears that, pursuant to criterion (b), generation produced inside a local network is not transporting power to other markets outside the local network. The Commission understands that criterion (b) applies in both normal and emergency operating conditions.[115]

iv. Criterion (c)—Not Part of a Flowgate or Transfer Path

99. Exclusion E3 criterion (c) specifies a ''local network'' does not contain a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an interconnection reliability operating limit. The Commission believes that this is an appropriate criterion.

d. Exclusion E4 (Reactive Power Devices)

100. Exclusion E4 excludes from the bulk electric system ''Reactive Power devices owned and operated by the retail customer solely for its own use.'' NERC explains that exclusion E4 is the technical equivalent of Exclusion E2 for reactive power devices and that the currently effective bulk electric system definition is unclear as to how these devices are to be treated. We believe that this is an appropriate exclusion that provides additional clarity and granularity to the definition of bulk electric system.

Summary

101. In sum, we propose to approve NERC's revised definition of the term bulk electric system, including the specific inclusions and exclusions. We believe that NERC's proposal provides a reasonable basis for the identification of bulk electric system elements and appears to improve upon the currently effective definition by: (1) Removing the language that provides for regional discretion, (2) removing the language ''generally operated at * * *'' so as to create a clear 100 kV threshold; and (3) providing additional clarity and granularity. Above, we have asked for comment on a series of questions regarding the applicability of the ''core'' definition and specific inclusions and exclusions. We believe that comments on these questions will assist in providing further clarity and understanding of the NERC proposal. We further note that although we propose to approve the definition in this rulemaking, the responses to our questions are intended to guide the Commission as to whether other action is necessary, for example, by directing NERC to develop a further modification to the definition or inclusions/exclusions pursuant to section 215(d)(5) of the FPA.

C. The Commission Proposes To Approve the NERC Rules of Procedure That Provide a Case-Specific Exception Process

102. As described above, in Docket No. RM12–7–000, NERC submitted proposed revisions to its Rules of Procedure that provide procedures for requesting and receiving case-specific exception from the definition of bulk electric system.[116]

103. Pursuant to FPA section 215(f), we propose to find that the exception process is just, reasonable, not unduly discriminatory or preferential, and in the public interest and satisfies the requirements of section 215(c). Further, we believe that the proposal satisfies the statement in Order No. 743 that NERC establish an exception process for excluding facilities that are not necessary for the reliable operation of the interconnected transmission network from the definition of the bulk electric system.[117]

104. NERC explains that it was not feasible to develop a single set of technical criteria that would be applicable to all exception requests so it developed the Detailed Information Form to ensure that a consistent baseline of technical information is provided for NERC to make a decision on all exception requests. This information and the proposed exception process allows NERC to provide consistent determinations on exception requests submitted from different

[110] NERC BES Petition at 23.

[111] *Id.* at 23 and Exh. G at 4.

[112] *Id.*, Exh. G at 5.

[113] The Commission notes additional differentiations may directly address this concern, such as applying a load limit, which was raised by the NERC System Analysis and Modeling Subcommittee (SAMS) in its effort to support Phase 2 of the bulk electric system definition project as a criterion to limit the exclusion of large cities and regions.

[114] To the extent the information requested is confidential, commenters may provide the information pursuant to 18 CFR 388.112 of the Commission's regulations.

[115] *See* NERC BES Petition, Exh. E at 59 (''The Commission directed NERC to revise its BES definition to ensure that the definition encompasses all Facilities necessary for operating an interconnected electric Transmission network. The SDT interprets this to include operation under both normal and Emergency conditions * * *.'').

[116] *See* Section I.D.2 above for further description of NERC's proposed revisions to the NERC Rules of Procedure.

[117] *See* Order No. 743, 133 FERC ¶ 61,150 at P 16.

regions involving the same or similar facts and circumstances, and allows NERC to take into account the aggregate impact on the bulk electric system of approving or denying all the exception requests. Finally, the exception process includes provisions for reporting information that may alter the status of an approved exception, verifying whether an exception continues to be warranted, and revoking an exception that is no longer warranted.[118] Thus, we believe that this process is equally efficient and effective as the Order No. 743 directive to establish an exception process for excluding facilities that are not necessary for the reliable operation of the interconnected transmission network. In addition, we believe that NERC's proposal appears to be clear, transparent, and uniformly applicable.

105. NERC and the industry should be commended for the development of the 100 kV threshold, the identified inclusions and exclusions, and the exception process. Together, this package of important reforms will bring valuable improvements to the process of identifying those facilities that are necessary for the operation of the interconnected transmission network, and thus should be included in the definition of bulk electric system. For these reasons, we propose to approve NERC's proposals, as discussed above.

106. The Commission seeks input from NERC and the industry, however, as to additional reforms that may be needed to the definition or to the Rules of Procedure to ensure that, over the long term, the facilities necessary to the reliability of the interconnected transmission network are captured in its definition. In particular, we note that while establishing a ''bright-line'' threshold of 100 kV has significant advantages, it may not capture all facilities that are necessary for the operation of the interconnected transmission network that fall below that threshold. As the Commission indicated in Order No. 743 and Order No. 743–A, its goal is that the definition of bulk electric system should include all facilities necessary for the operation of the interconnected transmission network, except for local distribution. Although the Commission indicated that one way to meet this goal was to establish a 100 kV ''bright-line'' threshold, the Commission also made clear that the ''bright-line'' threshold would be a ''first step or proxy'' in determining which facilities should be included in the bulk electric system.[119] Indeed, the Commission, agreeing with commenters, held that NERC should not necessarily stop at 100 kV and should, through the development of the exception process, ensure that ''critical'' facilities operated at less than 100 kV, and that the Regional Entities determine are necessary for operating the interconnection network.[120] The Commission clarified that including sub-100 kV facilities should be done in an ''appropriate and consistent'' manner.[121]

107. Recent events reinforce the Commission's statements in Order Nos. 743 and 743–A with respect to ensuring that sub-100 kV facilities, as appropriate, are included in the bulk electric system. The September 2011 Blackout Report concluded that certain sub-100 kV facilities, which were not designated as bulk electric system facilities, contributed to the cascading blackout affecting San Diego, California.[122] The September 2011 Blackout Report makes clear that, while certain sub-100 kV facilities can affect bulk electric system reliability, entities may not study or communicate their impacts and take appropriate action unless they are properly designated as part of the bulk electric system.[123] Thus, the September 2011 Blackout Report recommended that ''WECC, as the [Regional Entity], should lead other entities, including [transmission operators] and [balancing authorities], to ensure that all facilities that can adversely impact [Bulk-Power System] reliability are either designated as part of the [bulk electric system] or otherwise incorporated into planning and operations studies and actively monitored and alarmed in [real-time contingency analysis] systems.'' [124] Although the Blackout Report addressed an event in WECC, the recommendations in the Blackout Report should not be limited only to the Western interconnection. Indeed, as explained above, the recommendation in the September 2011 Blackout Report that sub-100 kV facilities be reviewed for inclusion in the bulk electric system is consistent with the Commission's findings in Order Nos. 743 and 743–A.

108. The NERC proposals at issue in this NOPR take steps to address the treatment of sub-100 kV facilities, as well as other facilities, necessary for the operation of the interconnected transmission network, through the exception process, which provides an avenue for Regional Entities, planning authorities, reliability coordinators, transmission operators, transmission planners, balancing authorities, and owners of system elements to submit a request to include a facility in the bulk electric system. We believe that regional entities, reliability coordinators, transmission owners, transmission operators, balancing authorities and other registered entities need to evaluate their sub-100 kV facilities, as well as other facilities, that are necessary to operate the interconnected transmission network in an ''appropriate and consistent'' manner to determine their potential impacts on bulk electric system reliability and, based on that review, seek to include those facilities in the bulk electric system through this proposed exception process.[125] These entities have the in-depth, ''on the ground'' knowledge and expertise of what facilities are critical to reliable operations in their local or regional area. As a result, we believe they bear primary responsibility to analyze the elements within their purview to ensure that the right facilities are included in the bulk electric system. We seek comment on how the relevant entities will conduct the review and seek inclusion of facilities.

109. The Commission expects that these entities will use the exception process as contemplated to include sub-100 kV facilities, and other facilities, necessary for the operation of the interconnected transmission network in the bulk electric system. Nonetheless, we note that relying on these entities alone may, in certain limited circumstances, have the potential to leave out sub-100 kV facilities necessary for the operation of the interconnected transmission network. For example, NERC or the Commission may, in the performance of their statutory functions and general oversight of reliability matters, discover additional sub-100 kV facilities that should be included. The joint NERC–FERC September 2011 Blackout Report, as noted above, is a prime example of this possibility. In addition, while we recognize that the owners and operators of the power grid take their reliability obligations seriously, there may be instances when not all of the facilities necessary for the operation of the interconnected transmission network are included in the bulk electric system.

110. Thus, while we propose to approve the package of reforms submitted by NERC, we seek comment

[118] NERC ROP Petition at 16.

[119] Order No. 743–A, 134 FERC ¶ 61,210 at P 40.

[120] Order No. 743, 133 FERC ¶ 61,150 at P 121.

[121] Order No. 743–A, 134 FERC ¶ 61,210 at P 103.

[122] *See* September 2011 Blackout Report at 96–97.

[123] *Id.* at 7–8.

[124] *Id.* at 96, Recommendation 17.

[125] NERC's performance of a final review of exception requests under the Rules of Procedure should ensure national consistency under that procedure.

on how the relevant entities will seek inclusion of sub-100 kV elements to ensure that all facilities that are necessary for the operation of the bulk power system are designated as bulk electric system elements consistent with the discussion above. These comments also should aid NERC, industry, and the Commission in further efforts, already underway in Phase 2, to refine the bulk electric system definition, the inclusions and exclusions, and the exception process.

111. In addition to general comments on the discussion above, we seek comments on the role NERC should have in initiating the designation of (or directing others to initiate the designation of) sub-100 kV facilities, or any other facilities, necessary for the operation of the interconnected transmission network for inclusion in the bulk electric system. The exception process as proposed does not provide that NERC may initiate an exception request. Given its statutory functions to develop and enforce Reliability Standards and its continent-wide perspective, NERC has technical understanding that may provide valuable assistance in the identification of bulk electric system facilities and elements. For example, NERC conducts disturbance assessments, oversees compliance monitoring and conducts seasonal assessments, all of which provide information and understanding regarding the operations of the bulk electric system. The Commission seeks comment on the role NERC should have in designating sub-100 kV facilities, and other facilities, for inclusion in the bulk electric system, directing Regional Entities or others to conduct such reviews, or itself nominating an element to be included in the bulk electric system.[126]

112. We also seek comment on the role the Commission should have with respect to the designation of sub-100 kV facilities, or other facilities, necessary for the operation of the interconnected transmission network for inclusion in the bulk electric system. As noted above, there may be circumstances (like the September 2011 Blackout Report) where the Commission, through the performance of its statutory functions, may conclude that certain sub-100 kV facilities not already included in the bulk electric system are necessary for the operation of the interconnected transmission network and thus should be included in the bulk electric system. While, as noted above, we expect that regional entities and others will take affirmative steps to review and include sub-100 kV elements and facilities, and other facilities, necessary for the operation of the interconnected transmission system in the bulk electric system, we seek comment as to how the Commission, if necessary, could ensure that such facilities are considered for inclusion in the bulk electric system. We also seek comment on instances when the Commission itself should designate (or direct others to designate) sub-100 kV facilities, or other facilities, necessary for the operation of the interconnected transmission grid for inclusion in the bulk electric system.[127]

1. Technical Review Panel

113. NERC's proposed exception process provides that ''[t]he Regional Entity shall not recommend Disapproval of the Exception Request in whole or in part without first submitting the Exception Request for review to a Technical Review Panel and receiving its opinion * * *'' [128] The technical review panel member must have the required technical background, must not have participated in the review of the exception request, and not have a conflict of interest in the matter.[129] The Regional Entity is not bound by the opinion of the panel, but the panel's evaluation becomes part of the record associated with the exception request and provided to NERC.

114. We see value in the Regional Entity receiving the independent opinion of a qualified technical review panel. NERC, however, does not explain why the proposed rules only require a technical review panel to provide an opinion where the Regional Entity recommends disapproval of an exception request. We seek comment from NERC explaining whether it considered obtaining the opinion of a technical panel for all Regional Entity recommendations and, if so, why the review is only required when a Regional Entity disapproves a request. Further, we seek comment on whether NERC should modify the exception process to require Regional Entities to submit all proposed determinations to a technical review panel regardless of the recommendation and receive the panel's opinion on each request.

2. Use of Industry Subject Matter Experts

115. Section 8 of the proposed exception process sets forth the procedures for NERC's review of a Regional Entity's recommendation. The NERC President will appoint a team of at least three persons with the technical background to evaluate an exception request. The members of the review team must have no financial, contractual, employment or other interest in the submitting entity or owner that would present a conflict of interest and must be free of any conflicts of interest in accordance with NERC policies.[130] NERC states that ''at the present time NERC anticipates that its review teams would be drawn from NERC staff resources, supplemented by contractors as necessary particularly where needed to provide specific relevant subject matter expertise. However, situations may arise in which NERC may need to call on industry subject matter experts to participate as members of review teams.'' [131]

116. We support NERC's proposal to use staff resources, supplemented by contractors as necessary, to make up the exception request review teams. We believe that consistent appointment of the same NERC staff and contractor resources, based on subject matter expertise, will promote a more uniform and consistent review of the Regional Entities' exception request recommendations.

D. The Commission Proposes To Approve NERC's Detailed Information Form

117. As described above, NERC developed the Detailed Information Form that the Regional Entity and NERC can use in evaluating whether or not the elements that are the subject of an exception request are necessary for operating the interconnected transmission network. The Detailed Information Form encompasses a wide range of potential configurations and appears to ensure that a consistent baseline of technical information is provided with all exception requests, in addition to the specific information and arguments provided by the submitting entity in support of its exception request. The information that the applicant may submit in support of an exception request will not be limited to the Detailed Information Form. The applicant will be expected to submit all relevant data, studies and other information that supports its exception request. Further, NERC may ask the

[126] Since NERC makes the final determination pursuant to the proposed process, a modified process may need to be created if NERC has a role in submitting requests. For example, a different entity would likely need to make the final determination.

[127] The Commission contemplates that, if it were to take such a step, it would provide an opportunity for notice and comment.

[128] NERC ROP Petition, Att. 1, Proposed App. 5C to the Rules of Procedure, section 5.2.4.

[129] *Id.* at App. 5C, section 5.3.

[130] NERC ROP Petition at 31.

[131] *Id.* at n. 29.

submitting entity to provide other data, studies and information in addition to the Detailed Information Form and the other information included by the applicant in the exception request.

118. We believe that this information will provide consistency with respect to the technical information provided with all exception requests and is an equally efficient and effective approach to developing a substantive set of technical criteria for granting and rejecting exception requests. Accordingly, we propose to approve the Detailed Information Form included in NERC's filing.

E. The Commission Proposes To Approve NERC's Implementation Plan for the Revised Definition of Bulk Electric System

119. As noted above, NERC requests that the revised definition ''should be effective on the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, the revised [bulk electric system definition] should go into effect on the first day of the second calendar quarter after its adoption by the NERC Board.[132]

120. NERC also requests that compliance obligations for all elements newly-identified to be included in the bulk electric system based on the revised definition should begin twenty-four months after the applicable effective date of the revised definition. While the Commission stated in Order Nos. 743 and 743–A that the transition period should not exceed 18 months from the date of Commission approval of the revised definition, the Commission also stated that it could approve a longer transition period based on specific justification.[133] NERC states that sufficient time is needed: (1) To implement transition plans in order to accommodate any changes resulting from the revised definition; (2) for entities to file for exceptions, and for the Regional Entities and NERC to process those exceptions to a final determination, pursuant to the proposed exception process; and (3) for owners of facilities and elements that are newly-included in the bulk electric system based on the definition to train their personnel on compliance with the Reliability Standards applicable to the newly-included facilities and elements, so that these entities can achieve compliance with applicable Reliability Standards by the end of the transition period. We believe that NERC has provided adequate justification for its implementation plan, as discussed above. Thus, although NERC's plan exceeds the 18 month implementation period set forth in Order No. 743, we propose to approve NERC's implementation plan.

F. NERC List of Facilities Granted Exceptions

121. In Order No. 743, the Commission stated that ''a Commission staff audit would review the application of the exemption criteria developed by NERC in NERC's or a Regional Entity's determination to approve an exemption for a particular facility.'' The Commission also stated that ''to facilitate such audits, the ERO should maintain a list of exempted facilities that can be made available to the Commission on request. NERC can decide how best to maintain the list, including determining whether or not to post it on the NERC Web site.'' [134]

122. NERC states that the proposed exception process does not include provisions for NERC to maintain a list of facilities that have received exceptions, as this is an internal administrative matter for NERC to implement that does not need to be embedded in NERC Rules of Procedure.[135] NERC states it will develop a specific internal plan and procedures for maintaining a list of facilities for which exceptions have been granted. Further, NERC explains that it has not yet determined how the list will be organized and structured and under what conditions the list will be made available on the NERC Web site or otherwise made available to any entities other than the Commission, citing concerns about confidential information and critical energy infrastructure information.[136]

123. We understand that NERC is continuing to develop the details on how it will maintain the list of facilities that have received exceptions. However, we also consider the maintenance of this list of facilities an important feature for tracking exceptions.[137] Thus, we propose that NERC file an informational filing within 90 days of the effective date of a final rule, detailing its plans to maintain a list and how it will make this information available to the Commission, Regional Entities, and potentially to other interested persons. We seek comment from NERC whether this deadline provides adequate time for NERC to finalize its plans and submit an informational filing.

124. While NERC states that it will maintain a list of facilities that have received an exception pursuant to the case-specific exception process, the petition does not indicate whether NERC will track an entity's ''declassification'' of current bulk electric system facilities based on the entity's self-application of the bulk electric system definition. It appears that, in some circumstances, the appropriate Regional Entity would receive a request that an entity be removed from the NERC Compliance Registry. For example, if an entity determines that its entire system satisfies the exclusion E1 for radial systems, the entity could apply to the appropriate Regional Entity to be removed from the NERC Compliance Registry. However, in other circumstances, it is not clear what, if any, notification an entity would provide to NERC or a Regional Entity when the entity self-determines that an element is no longer part of the bulk electric system. For example, a large utility with hundreds or thousands of transmission lines may initially determine that a configuration on its system does not qualify for the exclusion E3 local network exclusion, but subsequently determines that the configuration can be excluded. NERC's petition does not indicate whether an entity in such circumstance is obligated to inform NERC or the appropriate Regional Entity of that self-determination. It appears that NERC and the Regional Entities would need this information for their compliance programs, for audit purposes, and to understand the contours of the bulk electric system within a particular region. Accordingly, we seek comment on whether NERC's proposal should be modified to include an obligation for the registered entity to inform NERC or the Regional Entity of the entity's self-determination through application of the definition and specific exclusions E1 through E4 that an element is no longer part of the bulk electric system.

III. Information Collection Statement

125. The following collection of information contained in this Proposed Rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[138] OMB's regulations require approval of certain information collection requirements

[132] NERC BES Petition at 34.

[133] Order No. 743, 133 FERC ¶ 61,150 at P 131.

[134] *Id.* PP 117, 119.

[135] NERC ROP Petition at 49.

[136] *Id.*

[137] Order No. 743, 133 FERC ¶ 61,150 at PP 117, 119.

[138] 44 U.S.C. 3507(d) (2006).

imposed by agency rules.[139] The Commission solicits comment on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically the Commission asks that any revised burden estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated.

126. In Order No. 693, the Commission approved NERC's definition of the term bulk electric system and the associated information requirements.

127. In Order No. 743, the Commission directed NERC to develop a revised ''bulk electric system'' definition. The Commission explained that, by directing NERC to develop a revised definition, ''the Commission is maintaining the status quo (i.e., the current bulk electric system definition) until the Commission approves a revised definition. Thus, the Commission's action does not add to or increase entities' reporting burden.'' [140]

128. The immediate NOPR proposes to approve the revision to the definition of ''bulk electric system'' developed by NERC and an exception process to include or exclude specific elements in the definition of ''bulk electric system'' on a case-by-case basis. The Commission is basing its burden estimate below on the revised definition of ''bulk electric system'' developed by NERC.

129. The proposal in this NOPR would result in entities reviewing systems and creating qualified asset lists, submitting exception requests where appropriate, and certain responsible entities having to comply with requirements to collect and maintain information in mandatory Reliability Standards with respect to certain facilities for the first time.

130. *Public Reporting Burden:* While the Commission requests comment concerning the information collections proposed in this NOPR and the associated burden estimates, in particular, the Commission requests comment on the following issues.

131. First, we request comment on the estimated number of entities that will have an increased reporting burden associated with the identification of new bulk electric system elements as a result of the modified definition. NERC states in its filing that ''[i]t was not the intent nor the expectation of either the [standard drafting team] or NERC to either expand or reduce the scope of the [bulk electric system], or (with the likely exception of the NPCC Region) to increase or decrease the number of Elements included in the [bulk electric system], through the revised [bulk electric system] definition as compared to the current [bulk electric system] definition.'' [141] NERC adds that it has no specific basis to determine to ''the extent Elements currently included in the [bulk electric system] will become not included, nor to what extent Elements currently not included will become included.'' [142] In developing an estimate of the reporting burden associated with the inclusion of additional elements, like NERC, we assume that entities in the NPCC Region will be most affected, with a lesser affect in other regions.[143]

132. We reviewed Compliance registry information for the NPCC Region to determine the number and types of registered entities in the U.S. portion of the NPCC Region.[144]

We expect that transmission owners and distribution providers, and some generator owners, are most likely to identify new elements. Based on this, we estimate a range from 66 to 155 affected entities in the NPCC region, and for OMB reporting purposes identify below a median number of 111 affected entities in the NPCC region. Further, consistent with NERC's explanation, we do not expect a significant number of registered entities outside of the NPCC region to identify new elements under the revised bulk electric system definition. Accordingly, we estimate a total of 75 entities outside of the NPCC Region having new ''implementation plan and compliance'' related reporting burdens. We seek comment on these estimates to assist the Commission in arriving at final estimates.

133. Second, we seek comment on the reporting burden associated with exception requests. NERC indicates that ''there is currently not a basis for estimating the numbers of Exceptions Requests that will be submitted * * *.'' [145] We agree with NERC that there is difficulty in estimating a specific number of exception requests as this is a new process with no ''track record.'' Thus, rather than estimating a specific number of exception requests, we estimate a range of exception requests that may be submitted. As indicated in the table below, from the 1,730 total transmission owners, generator owners and distribution providers in the Compliance Registry, we estimate a range of 87 to 433 exception requests per year for each of the first two years after the effective date of a final rule. We request comment on this estimated range to assist the Commission in arriving at a final estimate of the number of possible exception requests.

134. Third, as indicated above, our estimates are based in part on an expectation that transmission owners, generator owners and distribution providers will experience more significant reporting burdens than other categories of registered entities. We seek comment on this expectation, and whether and to what extent other categories of registered entities (in addition to transmission owners, generator owners and distribution providers) may have a public reporting burden.

135. We estimate that the increased Public Reporting Burden for this Proposed Rule is as follows:

[138] 44 U.S.C. 3507(d) (2006).

[139] 5 CFR 1320.11 (2011).

[141] NERC BES Petition at 37.

[142] *Id.*

[143] While Reliability Standards do not require the reporting of information directly to the Commission, the application of Reliability Standards to additional facilities will have associated information collection and retention obligations.

[144] NPCC Compliance Registry information is available on the NPCC Web site at: *https://www.npcc.org/Compliance/Default.aspx.*

[145] NERC BES Petition at 38.

Requirement	Number and type of entity [146] (1)	Number of responses per entity (2)	Average number of hours per response (3)	Total burden hours (1)*(2)*(3)
System Review and List Creation [147].	333 Transmission Owners	1 response	80 (engineer hours)	26,640 Yr 1.
	843 Generator Owners		16 (engineer hours)	13,488 Yr 1.
	554 Distribution Providers		24 (engineer hours)	13,296 Yr 1.
Exception Requests [148]	1,730 total Transmission Owners, Generator Owners and Distribution Providers.	.15 responses in Yrs 1 and 2.	94 (60 engineer hrs, 32 record keeping hrs, 2 legal hrs).	24,393 hrs in Yrs 1 and 2.
		0.01156 responses in Yr 3 and ongoing.		1,880 hrs in Yr 3 and ongoing.
Regional and ERO Handling of Exception Requests [149].	NERC and 8 Regional Entities.	1 response	1,386.67 hrs	12,480 hrs in Yrs 1 and 2.
Implementation Plans and Compliance [150].	111 NPCC Region Registered Entities [151].	1 response	700 hrs in Yrs 1 and 2	77,700 hrs in Yrs 1 and 2.
			350 hrs in Yr 3 and ongoing.	38,850 hrs in Yr 3 and ongoing.
	75 Registered Entities from 7 other Regions.	1 response	700 hrs in Yrs 1 and 2	52,500 hrs in Yrs 1 and 2.
			350 hrs in Yr 3 and ongoing.	26,250 hrs in Yr 3 and ongoing.
Totals				220,497 hrs in Yr 1.
				167,073 hrs in Yr 2.
				66,980 hrs in Yr 3 and ongoing.

[146] The ''entities'' listed in this table are describing a role a company is registered for in the NERC registry. For example, a single company may be registered as a transmission owner and generator owner. The total number of companies applicable to this rule is 1,522, based on the NERC registry. The total number of estimated roles is 1,730.

[147] This requirement corresponds to Step 1 of NERC's proposed transition plan, which requires each U.S. asset owner to apply the revised bulk electric system definition to all elements to determine if those elements are included in the bulk electric system pursuant to the revised definition. *See* NERC BES Petition at 38.

[148] We recognize that not all 1,730 transmission owners, generator owners and distribution providers will submit an exception request. Rather, from the total 1,730 entities, we estimate an average of 260 requests per year in the first two years, based on a low to high range of 87 to 433 requests per year. Therefore, the estimated total number of hours per year for years 1 and 2, using an average of 260 requests per year, is 24,393 hours. We estimate 20 requests per year in year 3 and ongoing.

[149] Based on the assumption of two full-time equivalent employees added to NERC staff and 0.5 full-time equivalent employees added to each region's staff, each full-time equivalent at $120,000/year (salary + benefits).

[150] The Commission does not expect a significant number of registered entities outside of the NPCC region to identify new elements under the revised bulk electric system definition. NERC also states that the other Regional Entities do not expect an extensive amount of newly-included facilities. *See* NERC BES Petition at 38. ''Compliance'' refers to entities with new elements under the new bulk electric system definition required to comply with the data collection and retention requirements in certain Reliability Standards that they did not previously have to comply with.

[151] The estimated range of affected NPCC Region Registered Entities is from 66 to 155 entities.

Information Collection Costs: The Commission seeks comment on the costs to comply with these requirements. These cost estimates are calculated using the average of the ranges suggested in the burden hour estimates. It has projected the annual cost to be:

- *Year 1:* $13,641,200.
- *Year 2:* $10,435,760.
- *Year 3 and ongoing:* $4,343,520.

For the first two burden categories above, the loaded (salary plus benefits) costs are: $60/hour for an engineer; $27/hour for recordkeeping; and $106/hour for legal. The breakdown of cost by item and year follows:

- *System Review and List Creation (year 1 only):* (26,640 hrs + 13,488 hrs + 13,296 hrs) = 53,424 hrs * 60/hr = $3,205,440.
- *Exception Requests (years 1 and 2):* (sum of hourly expense per request * number of exception requests) = ((60 hrs * $60/hr) + (32 hrs * $27/hr) + (2 hrs * $106/hr)) * 260 requests) = $1,215,760.
- *Exception Requests (year 3):* (sum of hourly expense per request * number of exception requests) = ((60 hrs * $60/hr) + (32 hrs * $27/hr) + (2 hrs * $106/hr)) * 20 requests) = $93,520.
- *Regional and ERO handling of Exception Requests:* Between NERC and regional entities we estimate 6 full time equivalent (FTE) engineers will be added at an annual cost of $120,000/FTE ($120,000/FTE * 6 FTE = $720,000). This cost is only expected in years 1 and 2.

• *Implementation Plans and Compliance* [152] *(years 1 and 2):* (hourly expense per entity * hours per response * sum of NPCC and non-NPCC entities) = ($64/hour * 700 hours per response * 186 responses) = $8,332,800.

• *Implementation Plans and Compliance (year 3 and beyond):* We estimate the ongoing cost for year 3 and beyond, at 50% of the year 1 and 2 costs, to be $4,166,400.

Title: FERC–725–J ''Definition of the Bulk Electric System.'' [153]

Action: Proposed Collection of Information.

OMB Control No.: To be determined.

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: The proposed revision to NERC's definition of the term bulk electric system, if adopted, would implement the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the proposal would ensure that certain facilities needed for the operation of the nation's bulk electric system are subject to mandatory and enforceable Reliability Standards.

Internal Review: The Commission has reviewed the proposed definition and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimate associated with the information requirements.

136. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, email: *DataClearance@ferc.gov,* phone: (202) 502–8663, fax: (202) 273–0873].

137. Comments concerning the information collections proposed in this NOPR and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by email to OMB at the following email address: *oira_submission@omb.eop.gov.* Please reference FERC–725J and the docket numbers of this Proposed Rulemaking (Docket Nos. RM12–6–000 and RM12–7–000) in your submission.

IV. Regulatory Flexibility Act Analysis

138. The Regulatory Flexibility Act of 1980 (RFA) [154] generally requires a description and analysis of Proposed Rules that will have a significant economic impact on a substantial number of small entities. As discussed above, the Commission believes that the immediate effect of the proposal to approve the modification to the definition of bulk electric system and the exception process would likely be limited to certain transmission owners, generator owners and distribution service providers, as well as NERC and Regional Entities. Many transmission owners, generator owners and distribution service providers do not fall within the definition of small entities.[155] The Commission estimates that approximately 418 [156] of the 1,730 registered transmission owners, generator owners and distribution service providers may fall within the definition of small entities.[157]

139. The Commission estimates that of the 418 small entities affected there are 50 within the NPCC region that would have to comply with the Proposed Rule. The Commission assumes that the Proposed Rule would affect more small entities in the NPCC Region than those outside NPCC as it is assumed that there are more elements in NPCC that would be added to the bulk electric system based on the new definition than elsewhere. The Commission estimates the first year affect on small entities within the NPCC region to be $39,414.[158] This figure is based on information collection costs plus additional costs for compliance.[159] The Commission estimates the average annual affect per small entity outside of NPCC will be less than for the entities within NPCC. The Commission does not consider this to be a significant economic impact for either class of entities because it should not represent a significant percentage of the operating budget. Accordingly, the Commission certifies that this Proposed Rule will not have a significant economic impact on a substantial number of small entities. The Commission seeks comment on this certification.

V. Environmental Analysis

140. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[160] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[161] Accordingly, neither an environmental impact statement nor environmental assessment is required.

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[152] The cost and hourly burden calculations for this category are based on a past assessment (NPCC Assessment of Bulk Electric System Definition, September 14, 2009.). In that assessment NPCC indicated $8.9 million annually for operations, maintenance and additional costs. We estimated that roughly half of that cost actually relates to information collection burden. Using the resulting figure, we used a composite wage and benefit figure of $64/hour to estimate the hourly burden figures presented in the burden table.

[153] All of the information collection requirements for years 1–3 in the proposed rule are being accounted for under the new collection FERC–725J.

[154] 5 U.S.C. 601–612 (2006).

[155] The RFA definition of ''small entity'' refers to the definition provided in the Small Business Act (SBA), which defines a ''small business concern'' as a business that is independently owned and operated and that is not dominant in its field of operation. *See* 15 U.S.C. 632 (2006). According to the SBA, an electric utility is defined as ''small'' if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

[156] We note that in Order No. 693, the Commission estimated that the Reliability Standards in that the Final Rule would apply to approximately 682 small entities. *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1940. Because the current Proposed Rule would affect a smaller subset of the categories of registered entities, our estimate is lower than that cited in Order No. 693.

[157] The number of small entities is generated by comparing the NERC compliance registry with data submitted to the Energy Information Administration on Form EIA–861. Note, these numbers do not account for companies that may be registered in more than one role. For companies registered in more than one role, the burden will likely be higher than for those companies registered in only one role. We estimate that there are 381 companies and 418 registered roles, meaning that several companies are registered in more than one role. We do not believe this affects the certification below.

[158] For companies registered as more than one entity in the NERC compliance registry this figure will increase accordingly. That is, if a company is registered as a transmission owner and generator owner then the cost burden would be $78,828 ($39,414 * 2 = $78,828).

[159] We use fifty percent of the first year ''number of hours per response'' figure in the information collection statement for calculation under the assumption that smaller entities do not have complicated systems or will not have as many new elements on average as larger entities do.

[160] Order No. 486, *Regulations Implementing the National Environmental Policy Act,* 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[161] 18 CFR 380.4(a)(5).

VI. Comment Procedures

141. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due September 4, 2012. Comments must refer to Docket Nos. RM12–6–000 and RM12–7–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

142. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

143. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

144. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

145. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

146. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

147. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

List of Subjects in 18 CFR Part 40

Electric power; Electric utilities; Reporting and recordkeeping requirements.

By direction of the Commission. Commissioner Clark voting present.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–15944 Filed 7–3–12; 8:45 am]

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June 21, 2012
News Media Contact
Craig Cano | 202-502-8680

FEDERAL ENERGY REGULATORY COMMISSION NEWS
Docket Nos. RM12-6-000, RM12-7-000

FERC Proposes to Approve NERC's Revised Definition for Bulk Electric System

The Federal Energy Regulatory Commission (FERC) today issued a proposal that would approve the North American Electric Reliability Corporation's (NERC) revisions to the definition of the bulk electric system to provide greater clarity and ensure consistency in identifying system elements across the nation's reliability regions.

In response to a Commission directive, NERC in January 2012 filed revisions that:

- Establish a "core" definition that includes all transmission, real power and reactive power facilities operated or connected at 100 kilovolts or higher.
- Eliminate the discretion that Regional Entities now have to define the system in their region without any oversight from the Commission or NERC.
- Identify specific facility configurations that are included in or excluded from the definition.

Today's Notice of Proposed Rulemaking (NOPR) also proposes to approve NERC's new rules of procedure for adding elements to and removing them from the definition on a case-by-case basis. While proposing to approve the revisions to the definition of bulk electric system, the NOPR also seeks comment on certain issues, including the exclusion of certain facility configurations from the definition.

Comments on the NOPR are due 60 days after publication in the *Federal Register*.

R-12-23

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Document Content(s)

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June 21, 2012

Commissioner Cheryl A. LaFleur

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. : **RM12-6-000 and RM12-7-000**

Item No.: E-4

Statement of Commissioner Cheryl A. LaFleur on NERC's Revised Definition for Bulk Electric System

"Almost two years ago, in Order No. 743, the Commission directed NERC to redefine the term "bulk electric system" (BES). The Commission explained that the current definition gives Regional Entities broad discretion to identify BES facilities, which has resulted in inconsistencies across regions and potential gaps in reliability.

In my remarks at the time, I observed that the Commission used Order No. 743 to establish a new paradigm for Commission directives under section 215(d)(5) of the Federal Power Act. The Commission explained that directives should not be unduly prescriptive, but should instead identify and explain the Commission's reliability concerns, offer NERC guidance and suggestions as to acceptable solutions, and permit NERC to propose equally efficient and effective alternatives.

I am pleased that the Commission has adhered to this formula since Order No. 743 and I expect it to continue to do so. I am also pleased that NERC has responded to our challenge in Order No. 743 by proposing a definition that eliminates regional discretion, establishes a general bright-line threshold of 100 kV, contains a thoughtful and nuanced list of specifically included and excluded facilities, and provides an exception process to add or remove specific facilities.

While I believe that NERC has succeeded in addressing the Commission's technical concerns, and therefore support the NOPR, I note that the NOPR seeks comment on the status of facilities under several specific fact patterns. As the NOPR states, these questions are intended to develop a common understanding among the Commission, NERC, and the regulated community of how the new definition applies in certain ambiguous circumstances.

Additionally, the NOPR seeks comment on whether NERC has successfully excluded local distribution facilities from the BES. As I noted in a recent dissent,[1] section 215 of the Federal Power Act specifically excludes local distribution facilities from the Commission's reliability jurisdiction. The Commission must respect this limit on its jurisdiction. I also noted that in Order No. 743-A, the Commission deferred to this proceeding the critical question of whether the local distribution facilities excluded from the Commission's jurisdiction under section 215 are the same local distribution facilities excluded from the Commission's jurisdiction under section 201(b). I look forward to receiving comments on these important issues.

Finally, I want to thank Bob Stroh, Susan Morris, Nick Snyder and the entire FERC team for their diligence in participating in the Standards Development Process and for their hard work on this order. I also want to recognize and thank the NERC drafting team for developing a thoughtful and robust definition and for completing your work on time. I know that you, like all drafting teams, are volunteers and that your work on the definition was in addition to your day jobs at your companies. I appreciate your hard work and commitment to reliability."

[1] *City of Holland, Michigan Board of Public Works*, 139 FERC ¶ 61,055 (2012) (*Comm. LaFleur, dissenting*).

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Document Content(s)

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June 21, 2012

Commissioner Cheryl A. LaFleur

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. : **RM12-6-000 and RM12-7-000**

Item No.: E-4

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20120629-3007 FERC PDF (Unofficial) 06/29/2012

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revisions to Electric Reliability Organization Definition of Bulk Electric System of Rules of Procedure	Docket Nos. RM12-6-000 RM12-7-000

ERRATA NOTICE

(June 29, 2012)

On June 22, 2012, the Commission issued a "Notice of Proposed Rulemaking" in the above-captioned proceeding, *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 139 FERC ¶ 61,247 (2012). Footnote 92 of the order, which is a duplicate of footnote 91, is deleted.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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Document Content(s)

RM12-6-000 Errata.DOC.....1-1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

May 3, 2012

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: Request for Information
Revision to Transmission Vegetation Management Reliability Standard
Docket No. RM12-4-000

To Whom It May Concern:

Pursuant to the Notice Inviting Comments on Report ("Notice Inviting Comments") issued in the above-referenced proceeding on April 23, 2012, the North American Electric Reliability Corporation ("NERC") hereby requests additional information regarding the commissioning of the Pacific Northwest National Laboratory ("PNNL Report"). The Notice Inviting Comments quotes at length from a document that is not publicly available regarding the scope of the report and omits footnotes. NERC requests that the Commission release the document commissioning the PNNL Report to the extent possible.

As you are aware, comments on the report are due within 30 days of the issuance of the Notice Inviting Comments, *i.e.*, on May 23, 2012. Your immediate attention to this matter would be greatly appreciated.

Sincerely,

/s/ Stacey Tyrewala

Stacey Tyrewala
Attorney
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
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stacey.tyrewala@nerc.net

cc: David O'Connor
Officer of Electric Reliability

20120504-3072 FERC PDF (Unofficial) 05/04/2012

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RM12-4-000

Issued May 4, 2012

North American Electric Reliability Corporation
1120 G Street, N.W., Suite 990
Washington, DC 20005-3801

Attention: Holly A. Hawkins, Assistant General Counsel for Standards and Critical Infrastructure Protection

Reference: Data Request in Response to the North American Electric Reliability Corporation's Petition for Approval of Proposed Reliability Standard FAC-003-2 – Transmission Vegetation Management

Dear Ms. Hawkins:

On December 21, 2011, you filed on behalf of the North American Electric Reliability Corporation (NERC) its Petition for Approval of Proposed Reliability Standard FAC-003-2 – Transmission Vegetation Management. Additional information is required in order to better understand NERC's petition, as set out in the data requests below. NERC must respond within 21 days of the date of this request with all pertinent information and records. As appropriate, NERC may seek non-public treatment of information in the responses pursuant to sections 388.112 and 388.113 of the Commission's regulations.[1]

1. Provide the technical basis for the statement at page 6 of the petition that "The distances derived using the Gallet equation result in the probability of flashover in the range of 10^{-6}."

[1] 18 C.F.R. §§ 388.112, 388.113 (2011).

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2. Please explain how implementation of the maintenance strategies, procedures processes, or specifications used to prevent encroachment under Requirement R3 of the proposed standard is mandatory and enforceable.

3. Please explain whether or to what extent modifications to an "annual vegetation work plan" under proposed Requirement R7 allow Transmission Owners to delay completion of an annual vegetation workplan. If a delay is permitted, explain whether proposed FAC-003-2 requires an applicable entity to implement other corrective actions? Explain and provide examples with citations to specific Requirements.

4. Explain whether and to what extent "documented maintenance strategies" under Requirement R3 may be generalized and require no specific actions to prevent encroachments.

5. With respect to proposed Requirement R6, how will NERC and Regional Entity auditors determine whether a Transmission Owner performed a vegetation inspection "at least once per calendar year and with no more than 18 calendar months between inspections" at a particular location on the Transmission Owner's Right of Way?

6. Explain whether and to what extent proposed FAC-003-2 requires qualification or training of personnel directly involved in implementation of vegetation management, and provide citations to any relevant Requirements or sub-Requirements of any current Reliability Standard.

7. Does the proposed standard allow for any exceptions to the requirements of Requirement R6 other than a failure to timely perform a Vegetation Inspection as a direct result of a "natural disaster" as stated in footnote 5 of the proposed standard? Explain.

8. The proposed standard provides an effective date "on the first calendar day of the first calendar quarter one year after" the date of Commission approval. Explain why a 12-month transition period is necessary and appropriate for implementing this proposed vegetation management standard.

9. The proposed standard revises NERC's definition of "Right-Of-Way" (ROW). What obligations govern a Transmission Owner who identifies a vegetation condition that might encroach into the MVCD, if the vegetation is located outside of the ROW as defined by the TO under the proposed standard, but inside of the legal ROW?

This data request is issued pursuant to the authority delegated to the Director of the Office of Electric Reliability under 18 C.F.R. § 375.303 (2011) and is interlocutory.

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NERC is encouraged to e-file its responses with the Commission. Instructions for e-filing are provided on the Commission's website at www.ferc.gov/docs-filing/efiling.asp. Otherwise, if you choose to file hard copies, please address your response to:

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Irrespective of your filing method, please also provide a copy of your responses to:

Tom Bradish
Office of Electric Reliability
1800 Dual Highway
Suite 201
Hagerstown, MD 21740

Any questions regarding this letter should be directed to Mr. Tom Bradish at (301) 665-1391.

Sincerely,

Joseph H. McClelland, Director
Office of Electric Reliability

20120504-3072 FERC PDF (Unofficial) 05/04/2012

Document Content(s)

FAC-003 Data Request.DOC.....1-3

From:	Guy V. Zito
To:	grpStaff
Subject:	FW: NERC: FERC Data Request Issued in Response to NERC"s Petition for Approval of Proposed Reliability Standard FAC-003-2
Date:	Friday, May 04, 2012 8:24:25 PM
Attachments:	FAC-003-2 Data Request.pdf

To All,

FERC is submitting a request for data for the recently filed Vegman standard. NERC must provide data within 21 days and answer the questions the Commission staff proposes. This is generally not a good sign and indicative of a lack of coordination during the standard's development.

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Elizabeth Heenan [Elizabeth.Heenan@nerc.net]
Sent: Friday, May 04, 2012 3:41 PM
To: reg_corresp_notif
Subject: NERC: FERC Data Request Issued in Response to NERC's Petition for Approval of Proposed Reliability Standard FAC-003-2

To NERC Management and Regional Entity Executives:

Attached please find a FERC Data Request issued in response to NERC's Petition for Approval of Proposed Reliability Standard FAC- 003-2 – Transmission Vegetation Management, issued today by FERC in Docket No. RM12-4-000. NERC must respond within 21 days.

Thank you,

Elizabeth A. Heenan
Legal Assistant
North American Electric Reliability Corporation
1325 G Street NW, Suite 600
Washington, DC 20005
Cell: (202) 420-8795
Direct: (202) 644-8040

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RM12-4-000**

RESPONSE OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION TO OFFICE OF ELECTRIC RELIABILITY'S MAY 4, 2012 DATA REQUEST

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May 25, 2012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)**	**Docket No. RM12-4-000**

RESPONSE OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION TO OFFICE OF ELECTRIC RELIABILITY'S MAY 4, 2012 DATA REQUEST

On May 4, 2012, the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Director of the Office of Electric Reliability issued a data request pursuant to 18 C.F.R. § 375.303 (2011) in response to the North American Electric Reliability Corporation's ("NERC") December 21, 2011, petition for approval of proposed reliability standard FAC-003-2—Transmission Vegetation Management ("Petition"). In compliance with the Commission's data request, NERC's responses are set forth below.

I. DATA REQUEST RESPONSES

QUESTION 1:

Provide the technical basis for the statement at page 6 of the petition that "The distances derived using the Gallet equation result in the probability of flashover in the range of 10-6."

NERC Response:

The probability of flashover, given a drop in voltage to 85% of the "Critical Flashover Voltage (CFO)," is roughly .135% (or approximately 10^{-3}). This value represents the probability of a flashover, assuming the specified CFO is achieved or exceeded.

However, this is not the only event being considered when attempting to model the probability of a vegetation flashover. The probability of achieving a maximum switching overvoltage ("Peak Voltage") in excess of the CFO must also be considered. This is shown on page 40 in equation 6 of the Technical Reference Document, and is specified there as roughly 0.135% (also approximately 10^{-3}).

In other words, the conditional probability of flashover given that the 85% CFO has been exceeded is approximately 10^{-3}. However, the probability of the CFO being exceeded is *also* 10^{-3}. As these can be treated as two independent events, the probability is statistically "joint"

(the probability of exceeding the CFO and the probability of a flashover given the exceeding of the CFO are independent events). Accordingly, the two probabilities are to be multiplied, yielding a probability on the order of magnitude of approximately 10^{-6}.

For a more specific accounting of the number, the probability of an event (as defined in a standard normal table) being in excess of the mean plus three standard deviations is approximately 0.13%. Multiplying this value by itself (once for each independent event) results in a value of 0.000169% (technically 1.69 X 10^{-6}), or approximately a 1 in 591,716 chance of occurrence.

QUESTION 2:

Please explain how implementation of the maintenance strategies, procedures processes, or specifications used to prevent encroachment under Requirement R3 of the proposed standard is mandatory and enforceable.

NERC Response:

The Transmission Owner will be obligated to show detailed documentation that clearly explains their system with regard to the geography and how the Transmission Owner will execute the plan to prevent encroachment into the MVCD.

As stated on pages 35-36 of the Petition:

> Requirement R3 requires the Transmission Owner to have documentation describing its chosen approach(es) for managing vegetation. The approach must consider the movement of the conductor, as well as growth rate, control method, and inspection frequency. The measure for this requirement is as follows:
>
> *The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement.*
>
> In this case, the Transmission Owner is obligated to show documentation, and that documentation must be sufficient to satisfy the auditor that the information contained in that documentation is sufficient that the Transmission Owner can use it to prevent encroachment into the MVCD. The difference in sizes of applicable entities, the nature of vegetation, [consideration of climate,] and the number of techniques available to applicable entities to manage it require that the measure allow for sufficient flexibility in approach. For example, vegetation management in Arizona is likely to be much different from that in West Virginia. Similarly, the approach used to manage a small system may be described in a few short sentences, while the approach used on a much larger system might require several volumes to describe. Auditors will have to use judgment to evaluate the appropriateness of the documentation provided given the particular circumstances of the entity being audited. To guide them in this, the Violation Severity Levels provided for Requirement R3 gradate the severity of a violation based on the

completeness of the information provided. In this case, failures of the requirement would likely be identified during review of the document(s) as submitted in response to a data request to support an audit, spot-check, or a self-certification. The document(s) the requirement describes can generally be understood to encompass the broad strategy, direction and goals supported by analysis and information peculiar to the geographical area of the Transmission Owner and the characteristics of its system. This document generally should be the foundation for the detail and supporting evidence required in requirements 4 through 7. As a competency based requirement, this is the cornerstone of the Transmission Owner's program to ensure vegetation management is implemented to ensure no encroachment.

QUESTION 3:

Please explain whether or to what extent modifications to an "annual vegetation work plan" under proposed Requirement R7 allow Transmission Owners to delay completion of an annual vegetation workplan. If a delay is permitted, explain whether proposed FAC-003-2 requires an applicable entity to implement other corrective actions? Explain and provide examples with citations to specific Requirements.

NERC Response:

As stated on pages 39-40 of the Petition:

> Because of the dynamic nature of vegetation, the plan must also be dynamic. While in theory this might allow an entity to modify its plan to avoid compliance risk, such modification would not eliminate the obligation that the modified plan be executed to avoid encroachment of vegetation into the MVCD. [Stated another way, the ability to make any modification to an annual work plan is expressly conditioned such that the modification cannot result in encroachment of vegetation into the MVCD.] Any such encroachment would be a violation of R1 or R2, and any changes to the plan that resulted in such encroachment would be a violation of R7. The VSLs recommended for Requirement R7 are gradated based on the percentage of the final plan not completed. Such failures would be identified using NERC's normal Compliance Monitoring and Enforcement processes – primarily through self-certification and self-reporting, but also through audits, spot checking, compliance violation investigations, and complaints as appropriate. In order for auditors to make appropriate judgments as to the completed plan and any modifications, the initial work plan may be requested via a self certification or data submittal prior to its initiation and then compared to the completed plan at the end of the time period.

QUESTION 4:

Explain whether and to what extent "documented maintenance strategies" under Requirement R3 may be generalized and require no specific actions to prevent encroachments.

NERC Response:

The Transmission Owners will in fact be expected to show documentation of their strategy with sufficient detail to include specific actions to accomplish the maintenance strategies.

As stated in Exhibit A to the Petition at 19-20:

> R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.
>
> An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.
>
> An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:
>
> > *1. the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
> > *2. the work methods that the Transmission Owner uses to control vegetation*
> > *3. a stated Vegetation Inspection frequency*
> > *4. an annual work plan*
>
> The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.

QUESTION 5

With respect to proposed Requirement R6, how will NERC and Regional Entity auditors determine whether a Transmission Owner performed a vegetation inspection "at least once per

calendar year and with no more than 18 calendar months between inspections" at a particular location on the Transmission Owner's Right of Way?

NERC Response:

As specified in Measure M6, the Transmission Owner will be expected to provide evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records.

This measure is consistent with the approaches used to verify compliance with the current FAC-003-1 (M1.1, which accepts as evidence "documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1"). Additionally, this is consistent with the manner in which other standards are enforced as well. For example, PRC-005-1b (Transmission and Generation Protection System Maintenance and Testing) measures compliance with R2 based on the provision of documentation demonstrating implementation.

QUESTION 6

Explain whether and to what extent proposed FAC-003-2 requires qualification or training of personnel directly involved in implementation of vegetation management, and provide citations to any relevant Requirements or sub-Requirements of any current Reliability Standard.

NERC Response:

As discussed in the Petition (including at 23-24), the proposed FAC-003-2 Reliability Standard does not require qualifications or training of personnel directly involved in implementation of vegetation management.

QUESTION 7

Does the proposed standard allow for any exceptions to the requirements of Requirement R6 other than a failure to timely perform a Vegetation Inspection as a direct result of a "natural disaster" as stated in footnote 5 of the proposed standard? Explain.

NERC Response:

No. A Transmission Owner could seek an "Entity Variance," which would have to be vetted through the Standards Development Process and approved by the Commission, in order to have any sort of exception to this requirement.

QUESTION 8

The proposed standard provides an effective date "on the first calendar day of the first calendar quarter one year after" the date of Commission approval. Explain why a 12-month transition

period is necessary and appropriate for implementing this proposed vegetation management standard.

NERC Response:

As stated in Exhibit B to the Petition:

> The effective date is the date entities are expected to meet the performance identified in this standard. The effective date allows entities time to make revisions to their existing transmission vegetation management programs to comply with the new requirements. This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

To provide further explanation, the obligation to perform an *annual* inspection of *100%* of its applicable lines is a new threshold of performance being established by this standard, as the previous version only required entities "define a schedule for… ROW inspections." Establishing this new threshold will require additional financial planning and budgeting for some entities, as it goes beyond their current plans. For example, Alberta Electric System Operator provided the following comment during the development of the standard: "In many of the areas in Alberta, due to cold climate and arid conditions, we have slow vegetation growth rates. The requirement for minimum annual inspection is not necessary." Hydro One Networks, Inc., Orange and Rockland Utilities, Inc., and National Grid commented "Once per calendar year is not sensitive to local and environmental factors... Other TOs may be located in parts of the continent with little or no vegetation and not need a once per calendar year inspection." As such, although some entities may already perform some sort of inspection on an annual basis, providing a one year period for entities to plan and budget for the manner in which they will meet the requirements of the standard is reasonable.

QUESTION 9

The proposed standard revises NERC's definition of "Right-Of-Way" (ROW). What obligations govern a Transmission Owner who identifies a vegetation condition that might encroach into the MVCD, if the vegetation is located outside of the ROW as defined by the TO under the proposed standard, but inside of the legal ROW?

NERC Response:

The use of the term "legal ROW" in Question 9 is unclear. We assume that this term is intended to mean any other legal land rights of the Transmission Owner that are not considered part of the "Right-of-Way," based on the NERC definition of "Right-of-Way" shown below:

> Right-of-Way (ROW)

> The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

NERC's response below is based on this interpretation of the Commission's use of the phrase "legal ROW."

The following scenarios explain the obligations that govern a Transmission Owner (TO) who identifies a vegetation condition that might encroach into the Minimum Vegetation Clearance Distance (MVCD), if the vegetation is located outside of the ROW as defined by the TO under the proposed standard, but inside of the legal ROW.

1. A grow-in from a tree or the tree wall into the ROW. The definition of ROW provides for "The corridor of land under a transmission line(s) needed to operate the line(s)." Therefore, in order to operate the line consistent with its rating, the ROW includes space for "blowout" of the lines within the context of the MVCD. With respect to the grow in of a tree from outside the ROW as defined but within the legal ROW, the TO will use vegetations inspections to identify " those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection." In the event, an inspection shows that a tree has already grown inside the MVCD, the TO would be in violation of R1 item 1 or R2 item 1. Another way to consider this issue is that tree growing into the MVCD from the side is no different from a tree growing into the MVCD from below the line.

2. A fall-in of danger timber (dead, diseased or dying) from outside of the ROW but within the TO's control. The definition of inspection covers vegetation "….vegetation conditions on a Right-of-Way and those vegetation conditions *under the Transmission Owner's control* that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection." Under this requirement, if the TO is regularly identifying its danger trees and has a program for managing the risk of fall-in there would be no violation. Conversely, if an outage occurs and it is confirmed that the TO was not attempting to identify its danger timber risk, the TO would be in violation of R6:

> **R6.** Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW

Also, if the TO identifies the danger tree but puts no plan into effect to manage the risk of fall-in, the TO would be in violation of R7:

> **R7.** Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from

vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented.

The same is the case if the TO had knowledge of a probable encroachment into the MVCD and did nothing to eliminate the encroachment.

3. A fall-in of a green tree from outside of the ROW but within the TO's control. No practical inspection program or technology is capable of identifying which green or "healthy" trees may fall into the MVCD. Further, the fact that the TO owns additional ROW over and above than that needed by the MVCD is insufficient reason to cut healthy green trees. To require the cutting of green, healthy trees that pose no known threat would likely not be environmentally, socially or politically acceptable.

4. Acts of God. There will always be the possibility that Acts of God, such as tornadoes, strong thunderstorms and hurricanes will propel trees into lines from beyond the ROW and MVCD. Since Acts of God are beyond the control of the TO, there would be no violation if a tree from outside the ROW is propelled by an Act of God into the MVCD or line.

139 FERC ¶ 61,097
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Mandatory Reliability Standards for the Bulk-Power System	Docket Nos. RM06-16-010 RM06-16-011

ORDER ON MOTION FOR AN EXTENSION OF TIME
AND SETTING COMPLIANCE SCHEDULE

(Issued May 4, 2012)

1. On March 30, 2012, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a motion for an extension of time to submit a revised Resource and Demand Balancing Reliability Standard on Frequency Response and Frequency Bias, BAL-003 (March 30, 2012 Motion). In this order, we grant NERC's motion to the extent discussed herein and establish a compliance schedule for NERC to submit a revised BAL-003 Reliability Standard consistent with the Commission's directives in Order No. 693.[1]

I. Background

2. In Order No. 693, issued in March 2007, the Commission, *inter alia*, approved NERC's Resource and Demand Balancing (BAL) Reliability Standards, including BAL-003-0, which addresses frequency response and bias.[2] The Commission approved BAL-003-0, noting that Requirement R5 places a minimum magnitude on frequency bias, and that Requirement R2 identifies that the Frequency Bias be "as close as practical to, or

[1] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at PP 369-375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). *See also Mandatory Reliability Standards for the Bulk-Power System*, 130 FERC ¶ 61,218, *order on reh'g* (March 18 2010 Order), 131 FERC ¶ 61,136, *order on compliance filing*, 133 FERC ¶ 61,212 (2010).

[2] The terms Frequency Response and Frequency Bias are defined in the NERC Glossary of Terms Used in the Reliability Standards.

greater than, the Balancing Authority's [yearly average] Frequency Response."[3] The Commission concluded that "the minimum frequency response needed for Reliable Operation should be defined and methods of obtaining the frequency response identified."[4] Accordingly, in Order No. 693 the Commission approved Reliability Standard BAL-003-0 as mandatory and enforceable. In addition, the Commission directed the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that "defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved."[5]

3. On March 18, 2010, the Commission established a six-month compliance deadline for NERC to submit modifications to Reliability Standard BAL-003-0 responsive to the Commission's directives in Order No. 693.[6] NERC requested rehearing and clarification. On rehearing for further consideration, the Commission directed Commission staff to convene a technical conference to provide an opportunity for a public discussion regarding technical issues pertaining to the development of a frequency response requirement.[7] The Commission also directed NERC to submit a proposed schedule that included firm deadlines for completing studies and analyses needed to develop a frequency response requirement, and for submission of a modified BAL-003-0 Reliability Standard responsive to the Commission directives in Order No. 693.

4. On October 25, 2010, NERC submitted an action plan, which included estimated timelines for completing studies and analyses needed to develop a frequency response requirement. NERC indicated that it would complete the revised Reliability Standard by May 2012. On December 16, 2010, the Commission accepted NERC's proposed action

[3] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 370-373.

[4] *Id.* P 372.

[5] *Id.* P 375.

[6] March 18, 2010 Order, 130 FERC ¶ 61,218.

[7] March 18 2010 Order, 130 FERC ¶ 61,218, *order on reh'g*, 131 FERC ¶ 61,136 at P 15. On September 23, 2010, Commission staff convened the technical conference. The agenda for the technical conference included the following issues: (1) the fundamental physics that determine the frequency response of an interconnected Alternating Current power system; and (2) approaches used by various interconnections (domestic and international) to determine and measure the magnitude and sources of frequency response. *See* Supplemental Notice, September 14, 2010 at 2-3.

plan, including NERC's proposed deadline for filing a revised Reliability Standard by May 2012.[8]

II. March 30, 2012 Motion for Extension of Time

5. On March 30, 2012, NERC filed its motion for additional time to comply with Order No. 693. NERC explains that it will not meet its May 2012 deadline. NERC does not ask for an extension to file a revised Reliability Standard by a date certain but proposes to file a revised timeline with the Commission no later than 21 days following the end of the comment period that begins after the second of two technical conferences NERC proposes to convene with stakeholders in May 2012. NERC also proposes to make informational filings with the Commission on a quarterly basis following the proposed technical conferences to keep the Commission informed of its progress with respect to this issue.

6. In support of the March 30, 2012 Motion, NERC states that there are certain technological and practical impediments as well as the added complication of a market component that NERC alone is unable to address, and these elements necessitate additional time for development of a successful Reliability Standard.[9] NERC states that additional time will allow NERC and the standard drafting team to complete necessary analyses and research, gain support for the current draft of the standard and allow for input from both the industry and the Commission.

III. Discussion

7. The Commission first directed NERC to submit a revised BAL-003-0 Reliability Standard in 2007. Because of the importance of this standard to the reliability of the grid, the Commission later set a deadline for NERC to comply with the Commission's directive.[10] At NERC's request, the Commission subsequently approved a schedule that

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[8] *Mandatory Reliability Standards for the Bulk-Power System*, 133 FERC ¶ 61,212.

[9] In requesting rehearing of the March 18, 2010 Order, NERC also explained the highly technical issues related to Frequency Response and the necessity of conducting studies and analyses.

[10] NERC has identified the BAL-003 Reliability Standard as a high priority matter. *See* NERC 2011-2013 Reliability Standards Development Plan, Docket Nos. RM05-17-000, et al. (filed May 13, 2011) in which NERC listed Project 2007-12: Frequency Response as "High Priority Project No.5." and NERC 2012-2014 Reliability Standards Development Plan, Docket Nos. RM05-17-000, et al. (filed December 13, 2011) in which

(continued…)

adopted an extension, which NERC itself proposed. NERC now seeks more time. The Commission appreciates that these matters may be complex and that NERC is simultaneously working on other important matters, some at our direction. However, the Commission cannot overlook that it has been five years since the Commission first directed NERC to revise the BAL-003-0 Reliability Standard and NERC has yet to comply. Given the time that has elapsed, that Frequency Response is essential to the reliable operation of the grid,[11] and that the Commission already has granted NERC additional time at its request, the Commission is reluctant to grant any further extensions of time, let alone the undefined extension that NERC now seeks for filing a revised BAL-003-0 Reliability Standard.

8. Nonetheless, in the interest of ensuring a properly developed Reliability Standard, the Commission grants NERC an extension of time, explained as follows. First, NERC indicates that the BAL-003-0 standard drafting team plans to conduct a statistical analysis and additional research into the calculation of the Frequency Response Obligation.[12] The Commission is concerned that this additional analysis and research not extend so long as to delay progress on developing the revised Reliability Standard. Therefore, the Commission sets a compliance deadline for completing this analysis and research to no later than six months from the date of this order.[13] Second, the Commission grants NERC an extension of twelve months -- until the end of May 2013 -- for NERC to complete the remainder of its work and file a revised BAL-003-0 Reliability Standard with the Commission as directed in Order No. 693.

9. Finally, the Commission accepts NERC's proposal to file informational quarterly reports. The Commission directs that the informational reports be submitted on a quarterly basis from the date of this order. The reports shall describe the progress NERC is making toward completing its analysis and research as well as the progress it is making in completing work on the other issues and filing a revised BAL-003-0 Reliability Standard by May 31, 2013, as required by this order.

NERC listed Project 2007-12: Frequency Response as "No.10 in Reliability Priority," and tied for "No.2 in Time Sensitivity Priority."

[11] March 30, 2012 Motion at 16 ("Like reactive power and installed capacity, Frequency Response is essential to ensure the reliable operation of the North American power grid.").

[12] March 30, 2012 Motion at 23-24.

[13] The Commission leaves to NERC's discretion the procedures it believes it needs to complete this work so long as NERC completes the work in the allotted time.

The Commission orders:

(A) NERC's March 30, 2012 Motion is granted to the extent discussed herein.

(B) NERC is directed to complete its analysis and research and to submit modifications to Reliability Standard BAL-003-0 that comply with the Commission's directives as set forth in Order No. 693, as discussed in the body of this order.

(C) NERC shall file quarterly reports with the Commission, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

20120517-3002 FERC PDF (Unofficial) 05/17/2012

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426
OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD11-10-000

May 17, 2012

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005-3801

Attention: Holly A. Hawkins, Attorney

Reference: Compliance Filing

Dear Ms. Hawkins:

1. On November 17, 2011, the Commission issued an Order[1] approving Reliability Standard FAC-008-3 -- Facility Ratings, and directed the North American Electric Reliability Corporation (NERC) to submit a compliance filing within 60 days to revise the Violation Risk Factor for FAC-008-3 Requirement R2 from a "Lower" designation to a "Medium" designation.

2. On January 17, 2012, NERC submitted a filing in response to the November 17 Order. NERC proposed to assign a Medium Violation Risk Factor for Requirement R2 of FAC-008-3, as directed in the November 17 Order.

3. Notice of this filing was issued on January 18, 2012, with comments, protests or motions to intervene due on or before February 16, 2012. No protests or adverse comments were filed.

4. NERC's uncontested filing is accepted pursuant to the authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303.

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[1] *Order Approving Reliability Standard*, 137 FERC ¶ 61,123 (2011) (November 17 Order).

20120517-3002 FERC PDF (Unofficial) 05/17/2012

5. This action shall not be construed as accepting any other contingency plan pursuant to 18 C.F.R. § 375.303(a)(1)(i) or any other data or report pursuant to C.F.R. § 375.303(b)(3)(iv). This action shall not be construed as approving any other application including Electric Reliability Organization or Regional Entity Rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such acceptance or approval shall not be deemed as recognition of any claimed right or obligation associated therewith; and such acceptance or approval is without prejudice to any findings or orders which have been or which may hereafter be made by the Commission in any proceeding now or pending or hereafter instituted by or against NERC.

6. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Joseph H. McClelland, Director
Office of Electric Reliability

Document Content(s)

RD11-10-000.DOC.....1-2

20120517-3001 FERC PDF (Unofficial) 05/17/2012

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426
OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD11-3-000

May 17, 2012

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005-3801

Attention: Holly A. Hawkins, Attorney

Reference: Compliance Filing

Dear Ms. Hawkins:

1. On November 17, 2011, the Commission issued an Order[1] approving Reliability Standard FAC-013-2 – Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon, and directed the North American Electric Reliability Corporation (NERC) to submit a compliance filing within 60 days to (1) modify the Violation Severity Level language for Requirement R1 to correct an apparent typographical error; and (2) either (a) revise the Violation Risk Factors for FAC-013-2 Requirements R1 and R4 from a "Lower" designation to a "Medium" designation, or (b) provide additional justification for a "Lower" Violation Risk Factor designation.

2. On January 17, 2012, NERC submitted a compliance filing in response to the November 17 Order. NERC clarified the Violation Severity Level language in Requirement R1, as set out in the November 17 Order, and proposed that Requirements R1 and R4 be assigned a Violation Risk Factor of Medium.

3. Notice of this filing was issued on January 18, 2012, with comments, protests or motions to intervene due on or before February 16, 2012. No protests or adverse comments were filed.

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[1] *Order Approving Reliability Standard*, 137 FERC ¶ 61,131 (2011) (November 17 Order).

20120517-3001 FERC PDF (Unofficial) 05/17/2012

4. NERC's uncontested filing is accepted pursuant to the authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303.

5. This action shall not be construed as accepting any other contingency plan pursuant to 18 C.F.R. § 375.303(a)(1)(i) or any other data or report pursuant to C.F.R. § 375.303(b)(3)(iv). This action shall not be construed as approving any other application including Electric Reliability Organization or Regional Entity Rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such acceptance or approval shall not be deemed as recognition of any claimed right or obligation associated therewith; and such acceptance or approval is without prejudice to any findings or orders which have been or which may hereafter be made by the Commission in any proceeding now or pending or hereafter instituted by or against NERC.

6. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Joseph H. McClelland, Director
Office of Electric Reliability

Document Content(s)

RD11-3-000.DOC.....1-2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Reliability Standards	**)**	**Docket No. RM11-18-000**

REQUEST OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR RECONSIDERATION, OR IN THE ALTERNATIVE, REHEARING OF ORDER REMANDING THE TRANSMISSION PLANNING RELIABILITY STANDARDS

Gerald W. Cauley
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May 21, 2012

I. INTRODUCTION

Pursuant to Rules 713 and 212[1] of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Rules of Practice and Procedure, 18 C.F.R. §§ 385.713 and 385.212, the North American Electric Reliability Corporation ("NERC") hereby requests reconsideration, or in the alternative, rehearing of the Commission's April 19, 2012 order remanding the proposed Transmission Planning Reliability Standard TPL-002-0b ("Order No. 762" or "Remand Order").[2] The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC also directed NERC to utilize its Expedited Standards Development Process to develop timely modifications to footnote b in response to its remand.

By this filing, NERC requests reconsideration, or in the alternative, rehearing of FERC's directive to respond to Order No. 762 using NERC's Expedited Standards Development Process. The Edison Electric Institute, American Public Power Association, Electric Power Supply Association, Electricity Consumers Resource Council, and the National Rural Electric Cooperative Association have authorized NERC to state that they support NERC's position in this filing.

[1] *See*, 18 C.F.R. §§ 385.713 and 385.212 (2009).
[2] Transmission Planning Reliability Standards, 139 FERC ¶ 61,060 (April 19, 2012) (Order No. 762).

II. STATEMENT OF ISSUE FOR REHEARING

Pursuant to 18 C.F.R. § 385.713, NERC seeks rehearing on one issue in Paragraph 21 of Order No. 762, in which FERC directed the following:

> We urge NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule. In that regard, we require NERC to deploy its Expedited Reliability Standards Development Process to quickly respond to the remand. As the Commission noted in previous orders, the use of planned or controlled load interruption is a fundamental reliability issue and, certainty regarding the loss of non-consequential load for a single contingency event is warranted. Thus, using the Expedited Standards Development Process will more rapidly bring needed certainty to this fundamental reliability issue.[3]

Issue: The Commission should grant reconsideration, or in the alternative, rehearing of its directive to deploy NERC's Expedited Standards Development Process to quickly respond to the remand because the Expedited Standards Development Process provides a temporary solution to modify the standard that will require additional processing steps be taken within a year.

III. DISCUSSION OF ISSUE ADDRESSED BY THE REQUEST FOR REHEARING

In Order No. 762, FERC directed NERC to deploy its Expedited Standards Development Process to quickly respond to the Remand Order.[4] FERC stated that NERC should use the Expedited Standards Development Process to rapidly bring more needed certainty to the fundamental reliability issue regarding the loss of non-consequential load for a single contingency event.[5] Because the Expedited Standards Development Process will not result in a permanent fix to the standard, NERC is requesting that FERC reconsider its directive and allow NERC to modify footnote b in response to Order No. 762 using an aggressive schedule, but without formally invoking the Expedited Standards Development Process.

The Expedited Standards Development Process requires that one of three actions take place once a standard is developed using the expedited process. These actions are:

[3] Order No. 762 at P 21.
[4] *Id*.
[5] *Id*.

> • If the Reliability Standard is to be made permanent without additional substantive changes, then a SAR and a proposed Reliability Standard shall be submitted to the Reliability Standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay.
>
> • If the Reliability Standard is to be substantively revised or replaced by a new Reliability Standard, then a project for the new or revised Reliability Standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular Reliability Standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.
>
> • The Reliability Standard shall be withdrawn through a ballot of the stakeholders within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.[6]

At a minimum, with no substantive changes to the standard, if required to formally invoke the Expedited Standards Development Process, NERC will be required to develop a new SAR within a year and proceed through the regular standards development process. This could add months or even years to the process depending on where the standard falls in NERC's prioritization efforts, thereby delaying the possibility of obtaining a permanent fix to the footnote sooner. NERC believes going through these extra process steps, as required by the *Standard Processes Manual*, one year after responding to the remand is unnecessary given the considerable time already spent by NERC, FERC, and the industry in studying this issue and addressing it through the standards development process.

NERC understands the urgency in responding to Order No. 762 and producing revisions to footnote b that address the use of planned or controlled load interruption for single contingency events in response to the order. For this reason, NERC is working to revise the footnote on an aggressive schedule that will result in a permanent fix to the footnote. Formally

[6] North American Electric Reliability Corporation, *Standard Processes Manual*, Appendix 3A to the NERC Rules of Procedure. Available at: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf.

invoking the Expedited Standards Development Process will only slow down NERC's ability to develop a permanent solution to the footnote. Additionally, given NERC's efforts in prioritizing standards development, along with the significant work already undertaken by the standard drafting team and the industry to address this issue, requiring the Expedited Standards Development Process to be formally invoked is unnecessary and will serve to delay the implementation of a permanent solution to the issue.

NERC and the standard drafting team have made concerted efforts to address the footnote b issue since FERC issued an Order on March 18, 2010 directing NERC to respond to the Order No. 693 directives on this subject.[7] The standard drafting team has held numerous meetings to discuss this issue, all of which have been noticed and open to the public. Additionally, the industry has reviewed several iterations of footnote b. Any additional changes made to the footnote at this point will be in direct response to the Commission's guidance in Order No. 762. Importantly, NERC's proposed schedule to revise footnote b will allow time for industry review and balloting in accordance with NERC's standards development process, while still responding to Order No. 762 expeditiously.

NERC therefore respectfully requests that FERC withdraw its directive to formally invoke the Expedited Standards Development Process, and instead allow NERC to respond to the Remand Order using an aggressive schedule that will deliver a footnote responsive to Order No. 762 to the NERC Board of Trustees for consideration at the February 2013 meeting. This schedule will give NERC the ability to process footnote b revisions using its regular standards development process, but with some possible shortening of comment periods where the process so allows, while working to obtain industry consensus on a permanent solution to the footnote.

[7] Mandatory Reliability Standards for the Bulk Power System, 130 FERC ¶61,200 (March 18, 2010).

The NERC Standards Committee agreed to process the footnote b revisions using an aggressive schedule at its meeting held on May 10, 2012. At that meeting, the Standards Committee resolved to:

- Authorize posting the SAR to revise TPL-002 Footnote b for informal comment with no obligation to respond to the comments
- Assign the work to the existing standard drafting team
- Waive the initial 30-day comment period
- Post the following for a 45-day comment period with the formation of a new ballot pool during the initial 30 days of the comment period and an initial ballot during the last 10 days of the comment period:
    - TPL-001, TPL-002, TPL-003, TPL-004 from Project 2011-02 with the new Footnote b
    - TPL-001 from Project 2006-02 with the new Footnote b
- Direct the drafting team to vet the proposed revision informally before posting formally to gain assurance that the posted version of Footnote be will have stakeholder support.

Additionally, the Standards Committee agreed to support the above proposal on a project schedule to deliver the standard to the February 2013 Board of Trustees Meeting.

Part of the consideration in developing this timeline was FERC's directive in Order No. 762 to use Section 1600 of the NERC Rules of Procedure to gather additional data on specific instances of any planned interruptions of Firm Demand[8] under footnote b, including how frequently the provision has been used. NERC is working to develop a data request responsive to the Commission's directive that can be used to inform the standards development process.[9] However, obtaining data through the Section 1600 process will also take additional time that will be necessary to fully understand the impacts of past uses of footnote b in revising the footnote.

Finally, in responding to Order No. 762, NERC plans to amend footnote b in such a manner that the footnote can be applied to both the existing TPL-002-0b standard as well as to

[8] NERC Glossary of Terms Used in Reliability Standards defines Firm Demand as "That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions." Available at http://www.nerc.com/files/Glossary_of_Terms.pdf.

[9] The NERC Board of Trustees approved acting expeditiously on issuing a Section 1600 Data Request at its May 9, 2012 meeting.

the proposed TPL-001-2 standard filed with the Commission on October 19, 2011.[10] That standard was proposed to be remanded by the Commission in an April 19, 2012 Notice of Proposed Rulemaking because of the inclusion of footnote b in the standard (*i.e.*, footnote 12 in the proposed standard).[11] NERC plans on revising the footnote and balloting it in such a way that it can be included in both the currently-effective TPL-002-0b standard and the proposed TPL-001-2 standard, and presenting both options to the NERC Board of Trustees for approval at its February 2013 meeting. NERC will file the revised footnote b in response to the Commission's Order No. 762 along with an amended TPL-001-2 petition that modifies footnote 12 consistent with the changes made to footnote b by the end of February 2013.

Given NERC's plans to respond to the remand expeditiously and to address both TPL-002-0b, footnote b and TPL-001-2, note 12 by February 2013, NERC urges the Commission to defer issuing a final order on the proposed TPL-001-2 standard until the revised footnote can be presented to the NERC Board of Trustees and filed with FERC for approval in February 2013. This will ensure that both footnote b and note 12 are consistent with the Commission's guidance in Order No. 762.

Accordingly, NERC respectfully requests the Commission grant reconsideration, or in the alternative rehearing, of its directive to formally invoke the Expedited Standards Development Process in response to the directive in Paragraph 21 of Order No. 762 in order to allow NERC and the industry the opportunity to produce a revised footnote b that is responsive to the Commission's order.

[10] Petition of the North American Electric Reliability Corporation for Approval of a Revised Transmission Planning System Performance Requirements Reliability Standard and Five New Glossary Terms and for Retirement of Four Existing Reliability Standards, FERC Docket No. RM12-1-000, October 19, 2011.
[11] Transmission Planning Reliability Standards, Notice of Proposed Rulemaking, 139 FERC ¶61,059 (April 19, 2012).

IV. CONCLUSION

For the reasons set forth in this filing, NERC requests that FERC grant reconsideration, or in the alternative, rehearing, of its directive in Paragraph 21 of Order No. 762 to afford NERC time to respond to the order and produce a permanent fix to the standard.

Respectfully submitted,

/s/ Holly A. Hawkins

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 21st day of May, 2012.

/s/ Holly A. Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

TECHNICAL CONFERENCE ON GEOMAGNETIC DISTURBANCES TO THE BULK-POWER SYSTEM	**)** **)** **)**	**Docket No. AD12-13-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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May 21, 2012

I. INTRODUCTION

Pursuant to the Federal Energy Regulatory Commission's ("FERC" or "Commission") "Technical Conference Agenda" issued in the above-referenced docket on April 20, 2012, the North American Electric Reliability Corporation ("NERC") submits these comments following the April 30, 2012 Technical Conference on Geomagnetic Disturbances to the Bulk-Power System. Attached hereto are copies of the prepared statements that Gerry Cauley and Mark Lauby delivered at the technical conference on NERC's behalf.

NERC is grateful for the opportunity to participate in the technical conference. As explained by Messrs. Cauley and Lauby (see **Attachment A**), NERC's Geomagnetic Disturbance Task Force ("GMDTF") *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System* highlights the potential for voltage collapse and the damage or loss of a limited number of vulnerable transformers across the bulk power system of North America.

By this filing, NERC submits supplemental comments in response to the technical conference. As explained below, NERC proposes to work with the Commission to develop guidelines, objectives, and specific goals for enhancing the capability of the bulk power system to withstand severe geomagnetic disturbances, which, as described in the NERC report, can present a serious threat to reliability. Through this joint effort, NERC and the Commission will collaborate to implement detailed action plans, which include gathering information vital to space weather mitigation proposals, conducting a rigorous risk assessment, and filing periodic informational reports.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[1]

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III. COMMENTS

A. Background

The Electricity Subsector Coordinating Council ("ESCC"), in response to the action items identified in the NERC-DOE Report,[2] developed an industry roadmap approved by NERC's Board of Trustees, to address specific High-Impact, Low-Frequency ("HILF") events. Further, NERC's technical committees, in response to this roadmap, developed a detailed plan to address HILF events identified by the ESCC, including Geomagnetic Disturbances ("GMD").

The joint NERC-DOE Report found that the best approach to study HILF events was to organize industry-led task forces, including the formation of a GMD Task Force. The scope of

[1] Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

[2] *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System,* A Jointly-Commissioned Summary Report of the North American Electric Reliability Corporation and the U.S. Department of Energy's November 2009 Workshop ("NERC-DOE Report"), available at: http://www.nerc.com/files/HILF.pdf.

the GMD Task Force was approved by the NERC Planning Committee at its September 14-25, 2010, meeting.

As reflected in the statements of Gerry Cauley and Mark Lauby at FERC's April 30, 2012 technical conference (see **Attachment A**), the GMD Task Force *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*[3] ("Interim Report") highlights the potential for voltage collapse and the damage or loss of limited number of vulnerable transformers across the North American bulk power system. Specifically, the Interim Report identifies four industry recommendations:

- Improve tools for industry planners to develop geomagnetic mitigation strategies;
- Improve tools for system operators to manage geomagnetic impacts;
- Develop education and information exchanges between researchers and industry; and
- Review the need for enhanced NERC Reliability Standards.

The Interim Report provided a detailed plan of action for industry to address geomagnetic disturbance events. Based upon the findings and recommendations of the Interim Report, electric industry preparations for geomagnetic disturbance events should be a part of industry planning efforts, similar to preparations for earthquakes, hurricanes and snowstorms.

While the Interim Report provides a plan of action and several recommendations to address geomagnetic disturbances, there is still a great amount of uncertainty, and in some cases disagreement, around the specific technical issues that must be addressed before industry- and continent-wide corrective actions can be proposed. To ensure that "no regrets" actions are taken to address geomagnetic disturbances, NERC will apply the principles of reliability risk control.

B. Reliability Risk Control Based Approach

[3] Available at: http://www.nerc.com/files/2012GMD.pdf.

NERC works closely with industry members to take a practical approach to reliability risk control, and NERC is focusing on this process as a way to address emerging reliability issues. Through the process of risk control, NERC understands that all reliability hazards need to be qualified, that risks must be clearly defined as well as prioritized according to metrics of success, and that the most severe risks must be avoided. Furthermore, a rigorous risk assessment for GMD has not been done, and it is vital to avoid errors that may unintentionally make a complex issue worse.

In consideration of the reliability risk control process and the substantial costs often associated with incremental reliability improvements incurred by industry, NERC has determined that it is critical to correctly characterize the risk of geomagnetic disturbances to the reliable operations of the bulk power system prior to determining potential solutions. For example, the Interim Report identifies the potential for transformer failures to occur depending on the relative transformer health, design, geology and geomagnetic latitude. While all transformer designs and construction types have not been tested at varying levels of geomagnetic induced current, proponents of devices to mitigate geomagnetic induced currents have proposed that these devices should be installed on every transformer in service. However, without careful analysis, wide-scale deployment of the proposed mitigation methods would add an additional layer of complexity as well as costs into the power system. As noted in the technical conference, unintended consequences could occur. This added layer of complexity may present new and unknown reliability risks, whether in terms of device reliability and failure modes or in terms of human error in system planning and device maintenance.

The acceptance of a mitigation method requires accurate, peer-reviewed, and validated models. Further, the at-risk transformer population must be properly identified, and system

studies must be completed to ensure that mitigating geomagnetic induced current at one location does not adversely affect another. The additional risks of introducing new devices into the power system must be characterized before large-scale deployment takes place.

C. NERC's Findings and Clarifications

The Interim Report concluded that the most likely system impact to the bulk power system resulting from a high-impact, low-frequency strong geomagnetic disturbance is voltage instability, caused by a significant loss of reactive power support and a simultaneous dramatic increase in transformer reactive power absorption. Though the most likely result is voltage collapse, the GMD Task Force members agreed that, depending on the transformer health, design, geology and geomagnetic latitude, geomagnetic induced current flows can result in transformer loss-of-life, and may ultimately result in the failure of some transformers. The industry is well-equipped to face a small number of transformer failures; however, it is important to carefully quantify the nature of the reliability risk.

A number of previously completed government-sponsored studies have reached a conclusion that an extreme geomagnetic disturbance would result in irrecoverable damage to large amounts of bulk power system equipment. However, these prior studies did not engage the industry subject matter experts in long-term planning, equipment design and manufacture, solar storm characteristics, or real-time operations. Furthermore, the results documented in these prior studies, which predicted wide-spread equipment failures, were the product of the same principal authors. (See **Attachment B**).

NERC believes that further steps are needed to completely understand the appropriate ways to control the risks to reliability. NERC's position on the impact of geomagnetic disturbances to both bulk power system assets (including transformers) and power system

operations are supported by a number of peer-reviewed journal articles and industry studies. These reports reach similar conclusions to the Interim Report with regard to the likelihood of voltage collapse and that the impacts will not be as severe in length or duration as suggested by previously released governmental reports. (See **Attachment C**).

An oft-repeated error is made in equating the threat from geomagnetic disturbances to the threat from electromagnetic pulse ("EMP") and high-altitude EMP ("HEMP") events. While, at some level, the physical mechanisms of geomagnetic disturbances and electromagnetic pulses may be similar, it is an oversimplification of the science and statistics involved to equate random emanations from the sun interacting with the outer atmosphere with a direct attack of a nuclear weapon – the electro-magnetic characteristics, impacts and preventive system solutions to address these risks are very different.

The potential threats posed by EMP and HEMP events from direct and deliberate attacks on the bulk power system raise important and complex questions – particularly in relation to the assessment of costs to either users or the general population. Yet damage from EMP and HEMP attacks represent a reliability concern, given that such attacks could inflict economy-wide damage well beyond the scope of the electric power and transmission industry.

Accordingly, NERC and the ESCC have determined that the threat of EMP and HEMP attacks is beyond the scope of civilian power industry to address. Rather, the threat from such attacks is a matter for national defense policy and law enforcement agencies to address. Consensus needs to be reached on the tradeoffs between making massive investments for full protection against an EMP attack and addressing other pressing reliability priorities.

Finally, from a technical perspective, NERC notes the inappropriateness of using the incremental excitation current necessary for transformer core saturation as a way to suggest vulnerability of transformers to geomagnetic induced currents. (See **Attachment D**).

D. Action Plans

To address the two key risks of system collapse and transformer failures, NERC intends to coordinate its activities with FERC, the U.S. Department of Energy ("DOE"), the National Oceanic and Atmospheric Administration ("NOAA"), the U.S. Geological Survey ("USGS"), Natural Resources Canada ("NRCan"), The National Aeronautics and Space Administration ("NASA"), the Canadian Space Agency ("CSA"), the Electric Power Research Institute ("EPRI"), the Institute of Electrical and Electronics Engineers ("IEEE"), the International Electrotechnical Commission ("IEC"), the North American Transmission Forum ("NATF"), and other industry members, manufacturers and scientific organizations in two key areas: (1) assessing the vulnerability of the North American transformer fleet, incorporating power system modeling with space weather simulation and transformer thermal characteristics, and (2) surveying the industry for best practices in operations to respond to geomagnetic disturbances and updating the May 2011 NERC Industry Advisory "Preparing for Geomagnetic Disturbances."[4]

NERC will work closely with FERC to develop and file a responsive work plan and timetable, and will keep FERC apprised to progress through periodic informational reports. As part of this process, NERC requests that FERC identify the guidelines, objectives and specific goals that should be accomplished through these efforts, including a reasonable schedule for completion, given the: 1) the complexity of the problem at hand, 2) volume and sensitivity of

[4] Available at: http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2011-05-10-01_GMD_FINAL.pdf, with background at: http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2011-05-10-01_GMD_Background_FINAL.pdf.

data that must be gathered from industry, and 3) the cost and burden to the industry to support these efforts.

Given the uncertainty involved and the work required, immediate changes to the NERC Reliability Standards to address geomagnetic disturbances would be premature, although changes and additions will be considered in parallel as the proposed high-level actions are executed. Further, though the actions below provide an approximate schedule, NERC will continuously review to identify opportunities to accelerate the schedule when possible, without sacrificing reliability gains.

1. Initial Actions

While some of the most complex tasks will not likely be complete before the end of 2013, due to the scale and scope of scientific challenges, NERC has prioritized its geomagnetic disturbance efforts to support a "no regrets" strategy. Although NERC is examining ways to compress this schedule, some activities will take the scheduled time to support industry analysis and complete appropriate tests. As a starting point for discussion with FERC and industry, NERC proposes the following initial actions, which should take 18-24 months:

Identify facilities most at-risk from severe geomagnetic disturbance

As the first step in identifying the risk of geomagnetic disturbance to the bulk power system, NERC intends to complete a system-wide vulnerability assessment. To facilitate this vulnerability assessment in the near-term, NERC will request specific and detailed information from all North American asset owners (transmission and generator) on installed high voltage transformer construction (*e.g.*, shell or core type design, number of core legs, age, in-service time, winding configuration). Furthermore, special attention will be given to the evaluation of critical transformers, such as generator step-up units at large generating facilities.

Conduct wide-area geomagnetic disturbance vulnerability assessment

With the transformer data collected by NERC, a high level review will be conducted to identify and classify the at-risk population based on existing peer-reviewed research. This assessment will be based on a high level screening approach that will include transformer design, condition, geology and geomagnetic location.

To complete a comprehensive, wide-area vulnerability assessment NERC proposes that two models be implemented: 1) thermal response models of transformers to geomagnetic induced current must be developed for different construction types, and in parallel 2) a power system model that incorporates the effects of space weather and ground conductivity will need to be developed to simulate expected geomagnetic induced current flows. These two models will be combined for a complete picture that demonstrates the risk of both voltage collapse and transformer damage and failure as a result of geomagnetic disturbances. Once the models are publically available, NERC will then work with Planning Coordinators[5] to perform a detailed analysis of system and transformer impacts, and mitigation approaches.

Identify spare equipment availability

NERC's Spare Equipment Database, in coordination with other mutual assistance programs such as EEI's spare transformer equipment program (STEP), has been developed to facilitate the sharing of equipment amongst entities in the face of extreme conditions, such as geomagnetic disturbances or other catastrophic events. Location and transformer details gathered in the Spare Equipment Database may help organizations identify suitable replacements

[5] The NERC Functional Model defines Planning Coordinators as the functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas. http://www.nerc.com/files/Functional_Model_V5_Final_2009Dec1.pdf.

during a time of need. An assessment of transformer spares and transformer vulnerability will be completed by NERC in conjunction with industry members.

Enhance equipment specifications to be geomagnetic disturbance capable

In addition to assessing the vulnerability of the bulk power system, NERC proposes to work with industry and standards organizations such as the IEEE Transformers and Standards Committees, along with the IEEE Power and Energy Society, to enhance equipment specifications to withstand geomagnetic disturbances. As noted in the technical conference, initial discussions have already occurred with the responsible IEEE committees.

Enhance training for system operators and planners

NERC will concurrently work with industry experts to collect best practices and share information for system operations. This information will be used along with results from power system simulations to support the development and enhancement of training for system operators and planners.

2. Mid-Term Actions

Following the initial tasks of vulnerability assessment and industry outreach, NERC will continue work with EPRI, industry, manufacturers and the scientific community to develop models and tools to improve bulk power system reliability. The following mid-term actions, requiring 12-36 months, are proposed:

Refine probabilistic geomagnetic disturbance storm scenarios

NERC will continue working with NASA and the offices of SpaceWeather Canada, a division of NRCan, to expand the development of a family of geomagnetic disturbance event scenarios and to develop extreme event scenarios. This will include 1-in-100 year scenarios and a worst case scenario when they can be derived. Further, NERC will continue working with the

USGS and NRCan to develop detailed ground resistivity models vital to determining the ground potential that drives geomagnetic induced current levels in transformers.

Perform comprehensive tests of transformers to geomagnetic induced current

NERC will work with EPRI, DOE, industry participants, and equipment manufacturers to identify appropriate transformer test candidates and support testing efforts at a laboratory facility to be determined. Testing transformer thermal and operating response to geomagnetic induced current is an activity with a significant cost burden, but such testing is necessary to validate finite-element thermal models and corroborate operational responses to geomagnetic induced current. Testing would also enable improved performance monitoring and post-mortem analysis of transformer failures.

Increase geomagnetic induced current monitoring locations across North America

NERC will also promote the deployment of geomagnetic induced current monitors throughout North America, using the results of the vulnerability analyses to identify the most useful locations. NERC also supports the development of a data warehouse that would provide both neighboring organizations and the academic community access to non-confidential geomagnetic induced current data for further analysis. Data collected by a larger number of geomagnetic induced current monitors would be used to enhance system awareness and operational practices, and feed into improved analytical tools.

Develop analytical tools for system planners and operators to reliably manage geomagnetic disturbance impacts

NERC will continue work with EPRI and the academic community to develop tools for use by the industry. These tools should allow power system planners to analyze the effect of geomagnetic disturbances as the bulk power system evolves, and so that utility operators can be aware of impending geomagnetic disturbances and their effects and respond adequately. Models

will continue to be enhanced through collaboration with agencies such as NASA, CSA, USGS and NRCan, and with equipment manufacturers.

3. Long-Term Actions

NERC understands that geomagnetic disturbances will pose a risk beyond the solar maximum, which is expected to occur in May 2013. As such, NERC proposes the following continuing actions to address bulk power system reliability over the long term:

Improve space weather forecasting

NERC will work with the scientific community to support space weather forecasting improvements, so that forecasts provide adequate warning time frames to system operators. NERC will incorporate these enhancements into improved operational alerts and communications among bulk power system entities.

Ensure analysis of geomagnetic disturbances becomes part of the conventional planning and operation analyses

Geomagnetic disturbances are expected to become normal planning and operations scenarios for industry to analyze and for which they will prepare. Beyond the continued support of analytical and planning tool development, NERC will evaluate the Reliability Standards for changes and additions required to incorporate the planning and operations aspects that arise as result of geomagnetic disturbance data, assessment and studies.

Develop a spare equipment strategy for industry hazards

To address geomagnetic disturbances along with other HILF risks, NERC intends to facilitate the development of an industry-wide spare equipment strategy that addresses assessed hazards.

Develop equipment standards

NERC will continue working with organizations such as the IEEE and IEC to improve equipment standards and specifications where the results of assessments and analysis signify requirements.

Expand reactive resources and modify or replace equipment

The results of the assessments and analysis may indicate that additional reactive resources are needed to avoid system collapse, or where modifications to equipment such as protection and control, static var compensators and high voltage transformers may need to be modified or replaced to support correct operation or avoid equipment damage. NERC will work with the industry to address the need for such changes, support risk control, and consider necessary changes to the Reliability Standards that may be identified in the process.

E. Summary

NERC recognizes that there is a need for action on the impacts from geomagnetic disturbances. NERC also wants to ensure that a "no regrets" approach is taken and that mistakes that might adversely impact reliability are avoided. The complex technical issues involved in determining the risk associated with geomagnetic disturbances and deploying appropriate mitigating solutions must be planned carefully to ensure that no harm is done to bulk power system reliability in the process of addressing this low-probability, high-impact event.

NERC intends to develop a comprehensive plan, coordinated with FERC and subject matter experts from industry, manufacturers and scientific community, with milestones for oversight and progress reporting. Global expertise in the fields of science and engineering will be engaged to expand the collective understanding of the complex nature of geomagnetic disturbances and their effects on the bulk power system. Solutions will continue to be monitored, analyzed and refined as the knowledge base grows. NERC will also work with

industry throughout the course of these efforts to introduce and adjust risk controls that are well-suited to the complexity of the problem, and work will commence on interim mitigation steps where possible and appropriate.

IV. CONCLUSION

NERC is pleased to provide these comments in response to the Commission's Technical Conference.

Respectfully submitted,

/s/ Willie L. Phillips

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 21st day of May 2012.

/s/ Willie L. Phillips
Willie L. Phillips
Attorney for North American Electric Reliability Corporation

ATTACHMENT A

The following attachment is a reproduction of the written testimony submitted by Mark Lauby and Gerry Cauley to FERC at the April 30, 2012 technical conference.

Comments of Mark Lauby
Vice President and Director of Reliability Assessment and Performance Analysis
North American Electric Reliability Corporation
Atlanta, Georgia, USA

Good morning FERC staff and fellow panelists.

My name is Mark Lauby, Vice President and Director of Reliability Assessment and Performance Analysis of the North American Electric Reliability Corporation (NERC). I have a Master of Science of Electrical Engineering and more than thirty years experience in the bulk power system industry, and was recently elevated by the Institute of Electrical and Electronic Engineers to Fellow status.

Background – NERC/DOE HILF Report and Formation of NERC HILF Task Forces

In November 2009, NERC and the U.S. Department of Energy (DOE) held a two-day workshop on high-impact, low-frequency (HILF) event risk to the North American Bulk Power System which focused on a class of rare risks to bulk power system reliability. The proceedings of this workshop and recommendations were documented in a jointly released report in 2010, which outlined a plan to address these risks to the bulk power system, including geomagnetic disturbances. The report, released in June 2010, summarized the proceedings and discussions, including proposals for action and mitigating options.

Following the release of the NERC and DOE June 2010 assessment, the Electricity Sub-Sector Coordinating Council (ESCC) developed the Strategic Roadmap that provided an approach to address high-impact, low-frequency events through an organized combination of industry-led task forces and initiatives. Further, NERC's technical committees developed an action plan to address the ESCC's roadmap strategy. NERC's Board of Trustees endorsed this joint approach in November 2010.

As part of these joint activities, NERC, working with its stakeholders, created four task forces, including two that are relevant to this technical conference, with participation from industry, equipment manufacturers and risk experts to address key HILF risks. Two task forces, whose results address the topic of this technical conference, were formed: spare equipment database and geomagnetic disturbances or GMD. Both groups have completed their interim reports which were accepted by NERC's Board of Trustees. They are now working on the detailed work plans endorsed by the board.

The Spare Equipment Database (SED TF) Task Force recommended the creation of a spare equipment database for long-lead time equipment, with emphasis on high voltage transformers. The goal is to provide information needed to support industry if and when the loss of long lead-time equipment, such as bulk power system transformers, occurs. The work is now ongoing to finalize the data collection software and begin the collection of this information by the third quarter of 2012.

Geomagnetic Disturbance Task Force

The remainder of my remarks will now focus on the geomagnetic disturbance task force or GMDTF, which, in a unique way, brought together experts from each of the fields of space weather characteristics, earth sciences, space weather forecasting, bulk power system transients/dynamics, transformer manufacture and design, equipment design, as well as protection and control. Participants included members representing the users, owners and operators of the North American bulk power system, along with observers from manufacturers, government, academia, and vendors. For example observers included: U.S. Department of Energy, Department of Homeland Security, Department of State, National Oceanic and Atmospheric Administration Space Weather Prediction Center, National Aeronautics Space Administration, United States Geological Survey, Natural Resources Canada, all major transformer and blocking device manufacturers.

Throughout this assessment, NERC had access to the preeminent Canadian industry engineers and scientists, who were not invited to participate on either of today's technical conference panels. Due to its higher geomagnetic latitudes, Canada experiences more severe geomagnetic disturbances than in the United States, and this experience has translated into a deeper understanding of bulk power system impacts. Therefore, NERC was able to leverage the expertise of Canadian scientists and engineers who made significant contributions to the interim report. Sharing Canada's expertise today at this technical conference would have increased the value to all participants.

Overview – Geomagnetic Disturbances

Solar magnetic disturbances emanate from the sun, causing geomagnetic disturbances on Earth. According to space scientists, solar coronal holes and coronal mass ejections are the two main categories of solar activity that drive solar magnetic disturbances on Earth. Coronal mass ejections create a large mass of charged solar energetic particles that escape from the sun's halo (corona), traveling to Earth in 14 to 96 hours. These high-energy particles consist of charged electrons, along with coronal and solar wind ions. Geomagnetic disturbances, which can affect the power system, are produced when a large coronal mass ejection occurs and is directed at Earth. The interaction between the particle cloud and the earth's magnetic field can cause geomagnetically induced currents into the power system. The intensity of the effects on the power system depends on a number of factors such as the polarity of the magnetic structures created by charged particle cloud, geomagnetic latitude, directionality, and geology (electrical conductivity of the ground).

Geomagnetically induced currents can be measured directly using monitors of geomagnetically induced current typically attached to the neutral connections of power transformers. These monitors, along with alerts and warnings issued by the NOAA Space Weather Prediction Center or the Canadian Space Weather Forecast Centre, can provide the key information that a geomagnetic disturbance event is imminent or in progress and can support or trigger pre-planned operational decisions and actions.

GMD TF Mission

The Task Force set out to:

- Validate existing studies
- Identify the vulnerability of the bulk power system to geomagnetically induced currents
- Set an industry path forward towards addressing identified vulnerabilities

After review, it became evident that previously-released studies were based on a single data set that relied on closed-source methods and assumptions which could not be fully verified or validated by industry experts, researchers or scientists. Further, the reports that had been released had not been fully vetted by industry, nor were the results independently validated in an open forum such as the Institute of Electrical and Electronic Engineers. Therefore, NERC deemed it necessary to develop an open and transparent assessment of these reports, develop open-source simulation tools to support industry study, and provide recommendations applicable to the North American bulk power system.

Identified Risks and Effects

Based on the task force's work, two risks where identified from the introduction of geomagnetically induced currents to the bulk power system:

- Damage to bulk power system assets, typically associated with transformers
- Loss of reactive power support, which could lead to voltage instability and system collapse

The NERC Special Assessment interim report also explores the maximum "1-in-100 year" geomagnetic disturbance scenario. Study has shown that the effects of the "1-in-100 year" storm vary across North America. In addition, though the change in magnetic field over time has been used as a way to measure intensity, the study work found that this measure is not a complete way to characterize the effects of magnetic fields on the bulk power system. Rather, both the magnitude and rate of change are needed to characterize the geoelectric fields. Therefore, the electric or magnetic field waveform characteristics over time are an important way to study impacts on the North American bulk power system as well as equipment.

The task force found that, ultimately, the effects on the power system are defined by the magnitude, wave-shape and duration of geomagnetically induced currents. These dc-like currents cause half-cycle saturation in transformers, the effects of which are:

- *Harmonic currents* can cause some types of relays to operate incorrectly by either operating when they should not or by not operating when they should.
- *Fringing fields* can create hot spot heating (not to be confused with top oil heating) in transformers which, if sufficiently high and sustained for a relatively long duration, can affect the mechanical properties of oil impregnated paper insulation and reduce its expected life. The effect of this heating on the condition, performance, and insulation life of the transformer is also a function of a transformer's design and both the operational loading during the life of the transformer and during a geomagnetic disturbance event.
- *Excessive transformer reactive var consumption* can cause the system to collapse due to voltage instability. These effects depend on the extent of half-cycle saturation, which in-turn depends on transformer construction type and characteristics (for example, single-phase or three-phase, number of transformer legs, and shell or core-type).

Based on analysis of task force members, the effects on power system voltage stability from the excessive reactive consumption from transformers can become severe in a matter of tens of seconds, while transformer hot-spot heating effects can become an issue in tens of minutes or hours. Studies of the impact of geomagnetic disturbances should examine two particular problem areas: 1) studies to assess voltage stability for the short time frame, and 2) studies that look at the longer term thermal response of transformers.

Based on the work of the GMDTF, the effects on transformers and the power system as a whole, must consider geomagnetically induced currents and geoelectric field waveforms in terms of magnitude, frequency and duration. Induced geoelectric field waveforms were developed by NASA based on historical data which can be scaled for local earth resistivity conditions, which are now under development by the USGS. These waveforms are available for system engineers to use for their voltage stability and equipment thermal analysis.

The task force participants reviewed commonly identified transformer failures to understand the failure mechanisms. The available evidence regarding the failure of transformers during GMD events does not reveal a common mechanism of failure that could apply to a large number of transformers of different ages and makes, simultaneously. Objectively, the evidence to date shows that geomagnetically induced currents act as a stressor in vulnerable transformers. This suggests that one of the best ways to protect vulnerable transformers is to ensure proper maintenance and condition assessment, especially where it applies to oil moisture content and dissolved gasses, which have a direct proven impact on the withstand capabilities of a transformer under any type of electrical stresses such as lightning and short circuits.

The task force participants also reviewed the effects of GIC on system equipment such as static var compensators and capacitor banks, which provide reactive support critical to maintaining system stability during geomagnetic disturbances, when var demand is high. One of the important conclusions of the task force is that unless the effects of geomagnetic disturbances are considered in the design phase, improper operation of protection and control systems could remove them from service at a time where they effectively support reactive requirements of the system.

Projected System Impacts from Severe Geomagnetic Disturbances

Based on the overall work of the task force, the most likely system impact from a severe geomagnetic disturbance is voltage instability caused by a significant loss of reactive power support simultaneous to a dramatic increase in reactive power demand. Loss of reactive power support can be caused by the unavailability of shunt compensation devices (*e.g.*, shunt capacitor banks, static var compensators) due to harmonic distortions generated by transformer half-cycle saturation. This is exactly what caused the 1989 Hydro-Québec blackout.

The impact of reactive power loss on the reliability of the bulk power system must be taken in context of its impact on local and interconnection reliability. Notably, fast voltage collapse happens in a timescale of tens of seconds, while thermal impacts take much longer. Restoration times from system collapse due to voltage instability may be a matter of hours to days, perhaps similar to that following the August 2003 blackout affecting the northeast United States and parts of Canada.

NERC recognizes that other studies have indicated a severe geomagnetic disturbance event would result in the failure of a large number of extra-high voltage transformers. The work of the GMD Task Force documented in the report does not support this result. Instead, voltage instability is the far more likely result of a severe geomagnetic disturbance storm, although older transformers of a certain design and transformers near the end of operational life could experience damage. We came to this conclusion based on review of reports, results of ongoing studies and tests, and discussions with manufacturers of transformer equipment.

Implementing the Task Force's Recommendations and Next Steps

The potential for voltage collapse and the loss of a limited number of transformers is a serious issue, and NERC is working with industry to address the potential concern and mitigate any impacts to the reliable operation of the bulk power system. Though our results differ from previous studies regarding the magnitude of impacts, the uncontrolled collapse of the bulk power system is not an acceptable result from a severe geomagnetic disturbance. NERC, through industry groups and the GMD Task Force, will continue to amplify its work to provide power system planners and operators information to develop design criteria and the tools needed to identify problems; operating procedures; and, mitigating approaches to address impacts of geomagnetic disturbances. The approaches and need for action may differ depending on the geomagnetic latitude, geology, as well as transformer design and health.

To supplement the work of the GMD Task Force, NERC, the Electric Power Research Institute (EPRI), DOE, and 12 industry organizations have funded a collaborative research and development project focused on developing and enhancing tools to better prepare and manage effects from strong geomagnetic disturbances. In fact, open-source software to calculate geomagnetically induced current has been developed and already incorporated into a commercial power flow package. Additionally, the recent release of publically available "1-in-100 year" wave-forms by NASA will facilitate industry benchmarking and establish common frames of reference for comparative analysis.

Conclusion

There is much work yet to be done by industry through the GMDTF and other groups. A comprehensive plan has been developed, and documented in the interim report. NERC is now beginning towards completion of this plan including a system and equipment vulnerability assessment, industry training, and improved equipment specifications to name a few areas of focus.

Thank you for the opportunity to speak to the Commission today.

Gerry Cauley, P.E.
President and Chief Executive Officer (CEO)
North American Electric Reliability Corporation
Atlanta, Georgia, USA

Good afternoon FERC staff and fellow panelists.

My name is Gerry Cauley and I am the President and Chief Executive Officer (CEO) of the North American Electric Reliability Corporation (NERC). I am a graduate of the U.S. Military Academy, a former officer in the U.S. Army Corps of Engineers, and have more than 30 years experience in the bulk power system industry, including service as a lead investigator of the August 2003 Northeast blackout and coordinator of the NERC Y2K program.

NERC's mission is to ensure the reliability of the bulk power system of North America and promote reliability excellence and accountability. To ensure the reliability of the bulk power system, NERC relies on the combined expertise of the electric industry to draw realistic and credible conclusions to past and future events based on facts, not speculation or opinion. NERC works collaboratively with industry experts to address issues from standards development to responding to high impact, low frequency threats.

The NERC 2012 Special Assessment interim report on geomagnetic disturbances highlights the potential for voltage collapse and the damage or loss of a limited number of vulnerable transformers across the bulk power system of North America. Previous examples, such as the 1989 event in Hydro Québec demonstrate that severe solar storms represent a serious risk that can challenge the reliability of the bulk power system. NERC is working with industry to develop strategies and plans to control this risk.

NERC's interim report identifies four recommendations for industry:

- Improved tools for industry planners to develop geomagnetic mitigation strategies
- Improved tools for system operators to mange geomagnetic impacts
- Develop education and information exchanges between researchers and industry
- Review the need for enhanced NERC Reliability Standards

From a high level perspective regarding next steps, I see three key activities:

1. Vulnerability assessment through system analysis, and enhancing system design, operating procedures, and, if required, addition of neutral current blocking
2. Training of planners and operators
3. Spare equipment inventory management

I will cover each of thee with more specificity:

1. Vulnerability assessment through system analysis, and enhancing system design, operating procedures, and, if required, retrofitting of existing transformers

The conclusions of the 2012 Special Assessment interim report will be validated with the completion of a vulnerability assessment that NERC, along with industry in 2012, with final results being published in 2013. This joint effort will examine transformer vulnerability and will take into consideration the two primary risks to reliability from geomagnetic disturbances: reactive power loss and transformer hot spot heating. These two phenomena involve two very different time constants, seconds for reactive power loss and potential voltage collapse compared to tens of minutes for transformer heating.

NERC has supported the development of publically available simulation software to support the overall vulnerability assessment. We are now validating reactive power and thermal models to focus attention on the appropriate characteristics of the system. This information will be used to complete the high level vulnerability assessment which can be used to further industry discussion on mitigation strategies. To complete the vulnerability assessment, NERC is working with a number of private and governmental agencies. For example:

- Transformer vendors to determine the thermal characteristics of hot spot heating due to geomagnetic induced currents to identify the risk associated with specific transformer types
- U.S. Geological Survey and Natural Resources Canada to improve the ground impedance maps of North America
- Interconnection modeling groups (Eastern Reliability Assessment Group or ERAG, WECC, ERCOT, and Québec) to improve system models so the effects of geomagnetic disturbances on and across grids can be simulated
- U.S. National Aeronautics and Space Administration and Canadian Space Agency to develop a credible study design basis for systems, which can differ based on geology and geomagnetic latitude, as well as develop the theoretical maximum geomagnetic disturbance
- North American Transmission Forum to support review of confidential information on bulk power system and equipment performance, as well as to support the vulnerability assessment

To support these activities, NERC will pursue an industry voluntary data request on the existing transformer fleet to gather the important transformer characteristics and appreciate the risks to reliability. The data collected through this request would remain confidential and would be subject to NERC's Rules of Procedures regarding data confidentiality. If there is low industry participation and the data cannot be obtained through other avenues, NERC can make a mandatory request for information under Section 1600 of its Rules of Procedure.

Further, we are reviewing the existing NERC Alert on geomagnetic disturbances, to determine if it requires updating with recommendations outlined in the NERC report to ensure that the guidance given reflects the most recent information.

2. Training of planners and operators

NERC will continue to educate industry on the topic of geomagnetic disturbances, work with industry to refine operator tools and procedures, and to consider actions such as preemptively

increasing reserves, enabling forced cooling or taking equipment out of service in advance of storm. As part of this transfer of knowledge, it will be vital that open-source models are developed to facilitate industry learning, study and action. Further, NERC will also add training as part of its Operator Certification program.

3. Spare equipment inventory management

The industry continues to work hard to demonstrate its commitment to reliability in the response to high impact, low frequency events. One way is to develop programs to share spare equipment in the event of a severe event. NERC's Spare Equipment Database has been now fully vetted by industry and will be re-launched with specific focus on spare transformer equipment. The Spare Equipment Database is a voluntary program whereby owners of long lead-time transformers would share information about their spares in a database for potential equipment sharing.

In addition, the IEEE Transformers committee has begun development on a guide on transformer and step response **specifications** to meet the service conditions related to a geomagnetic disturbance as well as the magnitude and stress cycle due to geomagnetically induced current transformers should be designed to withstand. This project was initiated at the spring 2012 meeting of the IEEE Transformers Committee in Nashville, Tennessee. We will monitor the progress of this effort, and provide technical expertise as warranted to its conclusion.

From an operational perspective, more useful forecasting is needed to support operator action. The U.S. National Oceanic and Atmospheric Administration (NOAA) and SpaceWeather Canada need to enhance warning time frames and granularity of forecasts so industry can take the right action, in the most affected parts of North America.

The GMD task force interim report provided a roadmap for action for industry to address GMD. For industry to recognize that, just as they prepare for earthquakes, hurricanes and snowstorms, preparations for GMD should be a part of their planning efforts. It is important for us to learn from those who have had experiences with GMD, to get the source code information out to industry and train the planners and system operators to deal with these events.

Thank you for the opportunity to speak to the Commission today and I welcome your questions.

ATTACHMENT B

This attachment provides references to frequently-cited studies that conclude that a strong, extreme geomagnetic disturbance would result in irrecoverable damage to large amounts of bulk power system equipment. Note these studies are the product of the same principal authors.

High-Impact, Low-Frequency Event Risk to the North American Bulk Power System
Published by NERC, U.S. Department of Energy, 2010
http://www.nerc.com/files/hilf.pdf

Geomagnetic Storms and Their Impact on the U.S. Power Grid Meta R-319
John Kappenman
Published by Oak Ridge National Laboratory, January 2010
http://www.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf

Report of the Commission to Assess the Threat to the United States from Electromagnetic Pulse (EMP) Attack
Published by the EMP Commission, 2008
http://www.empcommission.org/docs/A2473-EMP_Commission-7MB.pdf

Executive Report of the Commission to Assess the Threat to the United States from Electromagnetic Pulse (EMP) Attack
Published by the EMP Commission, 2004
http://www.empcommission.org/docs/empc_exec_rpt.pdf

Low-Frequency Protection Concepts for the Electric Power Grid: Geomagnetically Induced Current (GIC) and E3 HEMP Mitigation – Meta R-322
John Kappenman
Published by Oak Ridge National Laboratory, January 2010
http://www.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-322.pdf

Management of the Geomagnetically Induced Current Risks on the National Grid Company's Electric Power Transmission System
A. Erinmez, J. Kappenman, W. Radasky
Journal of Atmospheric and Solar-Terrestrial Physics, Volume 64, Issues 5–6, March–April 2002, Pages 743-756
http://www.sciencedirect.com/science/article/pii/S1364682602000366

Severe Space Weather Events-Understanding Societal and Economic Impacts Workshop Report
Published by the National Research Council of the National Academies of Science, Engineering, and Medicine, 2008

http://www.nap.edu/catalog/12507.html

ATTACHMENT C

This attachment provides references to independent technical reports and studies that support the NERC technical findings and conclusions on geomagnetic disturbances

Developing Threats: Electro-Magnetic Pulses (EMP)
United Kingdom House of Commons - Defence Committee, February 2012
http://www.publications.parliament.uk/pa/cm201012/cmselect/cmdfence/1925/192504.htm

Impacts of Severe Space Weather on the Electric Grid
JASONS Summer Study – Department of Homeland Security, November 2011
http://www.fas.org/irp/agency/dod/jason/spaceweather.pdf

Protection against geomagnetic storms
Published by Svenska Kraftnät, 2011
http://www.svk.se/Global/02_Press_Info/Pdf/120330-Skydd-mot-geomagnetiska-stormar.pdf

Hydro One GMD Preparedness Plan for Cycle 24
L. Marti, Filed with FERC in Docket No. AD12-13-000, May 8, 2012
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20120508-5018

Simulation of Transformer Hot-Spot Heating due to Geomagnetically Induced Currents
Marti L.; Rezaei-Zare, A.; Narang, A.
Submitted for publication to *IEEE Transactions on Power Delivery*

Effects of GIC on Power Transformers and Power Systems
Girgis, R.; Vedante, K.
Presented at the IEEE T&D Conference & Exposition held in Orlando, FL, May 7 – 10, 2012

GIC occurrences and GIC test for 400 kV system transformer
Lahtinen, M.; Elovaara, J.
IEEE Transactions on Power Delivery, vol.17, no.2, Apr 2002

Characteristics of transformer exciting-current during geomagnetic disturbances
Walling, R.A.; Khan, A.N.;
IEEE Transactions on Power Delivery, vol.6, no.4, pp.1707-1714, Oct 1991

Calculation techniques and results of effects of GIC currents as applied to large power transformers
Girgis, R.S.; Ko, C.-D.
IEEE Transactions on Power Delivery, vol.7, no.2, pp.699-705, Apr 1992

ATTACHMENT D

Transformer Excitation and Geomagnetic Induced Currents

The facts about transformer overexcitation, and its differences from the half-cycle saturation that might be cause by GIC, are discussed in detail below. The key points are: 1) GIC can result in saturation of the transformer core, but it is a different phenomenon than overexcitation and does not result in elevated operating voltage or stress the dielectric strength of the insulation, and 2) while the level of GIC necessary to drive the transformer into half-cycle saturation is of some interest, the more important concern is the extent to which the GIC results in an offset of the transformer flux which defines the extent to which the transformer is saturated.

Overexcitation limits for transformers are based on the applied voltage and frequency. Transformer overexcitation can result in higher than normal operating voltage that stresses the dielectric strength of the insulation as well as saturation of the transformer core. Overexcitation limits are on the order of 10 seconds for 40 percent overexcitation and up to minutes for 10 percent overexcitation. Assuming rated frequency, 40 percent overexcitation would require applying 1.4 pu voltage to the transformer and 10 percent overexcitation would require applying 1.1 pu voltage. The resulting insulation stress accounts for the relatively low overexcitation limits. The amount of overexcitation that will saturate the transformer core varies, but typically is on the order 10 percent to 20 percent depending on the design specification. Overexcitation above the specified value results in non-sinusoidal and non-symmetric excitation current rich in harmonics, including even harmonics. The harmonics present and the level of each are dependent on whether the transformer is single-phase or three-phase, shell-form or core-form, and the number of “legs” in the core. Since the excitation current magnetizes the core, it can be viewed as a shunt reactance similar to the charging current for a transmission line which is modeled as a shunt capacitance. A full model for the transformer includes shunt branches for magnetizing and core losses, but these branches are ignored in models for short circuit and powerflow programs because they are high impedances at nominal frequency and voltage. The phenomenon that the excitation current is a shunt current explains why transformer differential relays have harmonic restraint to prevent operation during magnetizing inrush or overexcitation.

Statements such as “[d]riving a transformer to 10% overexcitation requires only a very small GIC” are imprecise in that, while both overexcitation and GIC may result in transformer saturation, GIC does not result in overexcitation of the transformer in the same context as this term is typically used. GIC can result in saturation of the transformer core; however, it is a different phenomenon than overexcitation and does not result in elevated operating voltage or stress the dielectric strength of the insulation. When overexcitation occurs due to high voltage and/or low frequency, the level of saturation is essentially the same on the positive half-cycle as it is on the negative half-cycle. In contrast the GIC flowing through a transformer requires a proportional flux, and because GIC is a quasi-direct current it results in a corresponding dc offset in both the excitation current and the flux resulting in saturation of the core every half cycle. It is clear is that GIC cannot replicate the overexcitation achieved when applying high voltage/low frequency to the transformer, but the end effects related to transformer heating and harmonics are a concern regardless of whether their origin is overexcitation in a classical sense or due to GIC.

The level of GIC necessary to drive a transformer into half-cycle saturation is a function of the transformer design and the operating point on the transformer saturation curve (which defines the relationship between flux and exciting current). While the level of GIC necessary to drive the transformer into half-cycle saturation is of some interest, the more important concern is the extent to which the GIC results in an offset of the transformer flux which defines the extent to which the transformer is saturated. To understand the distinction, it is important to consider the two regions on the transformer saturation curve. The transformer saturation curve has two regions: (i) the steep slope below the knee of the curve where the slope is defined by the magnetizing inductance and (ii) the flatter portion above the knee of the curve where the slope is defined by the air-core inductance. Once the transformer saturates a significant portion of the flux is forced outside the transformer core resulting in heating of transformer components that are not part of the normal flux path.

Transformer designs have evolved in response to purchasers placing a higher valuation on losses, resulting in a reduction in excitation current from values on the order of 0.01 pu down to values on the order of 0.001 pu. This means that the current required to achieve rated flux in the transformer core has been reduced by a factor of approximately 10. This results in a steeper

slope below the knee of the saturation curve because the magnetizing inductance is increased by a factor of approximately 10. For a transformer operating just below the knee of the transformer saturation curve the amount of current necessary to increase the flux to the point of saturation is therefore less for a modern transformer design with lower exciting current. However, it is important to note that the incremental current necessary to increase the flux to the point of saturation is relatively small in either case (*i.e.*, for either a newer transformer with lower exciting current or an older transformer with higher exciting current) when compared to the incremental current necessary to increase the flux once the transformer is saturated. This is because the incremental current necessary to increase the flux once the transformer is saturated is dominated by the air-core inductance which is much lower (by 2 to 3 orders of magnitude) than the magnetizing inductance. As a result, when GIC circulates through a transformer the resulting level of half-cycle saturation is relatively insensitive to the rated magnetizing current as demonstrated by Walling and Khan in their October 1991 paper in the IEEE Transactions on Power Delivery. The end result is that the level of saturation caused by GIC does not vary significantly as a function of the transformer rated magnetizing current or the lower losses of modern transformer core designs. Rather, the design of the transformer as it relates to the air-core inductance (*e.g.*, core-form versus shell-form) is the dominant design factor that influences the level of saturation resulting from a given level of GIC.

Critical Energy Infrastructure Information Has Been Redacted From This Public Version

May 31, 2012

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: ***North American Electric Reliability Corporation,***
Docket No. RM06-16-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this filing in compliance with Paragraph 629 of the Federal Energy Regulatory Commission's ("FERC") Order No. 693. Order No. 693 requires that NERC provide a quarterly informational filing regarding the timeframe to restore power to the auxiliary power systems of U.S. nuclear power plants following a blackout as determined during simulations and drills of system restoration plans. This filing contains the referenced material pertaining to the first quarter of 2012.

NERC's filing consists of the following:

- This transmittal letter;
- A table of contents for the entire filing;
- A narrative description summarizing the data collected;
- Official Data Request to Fulfill FERC Order No. 693 Requirements: Restoration of Nuclear Power Plant Off-site Power Sources (**Exhibit A**); and
- Restoration of Nuclear Power Plant Off-site Power Sources Data: 1st Quarter 2012 (**Exhibit B**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Andrew M. Dressel
Andrew M. Dressel

Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

MANDATORY RELIABILITY STANDARDS FOR THE BULK POWER SYSTEM	**)** **)**	**Docket No. RM06-16-000**

FIRST QUARTER 2012 COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO PARAGRAPH 629 OF ORDER No. 693

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May 31, 2012

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EXHIBIT A – Official Data Request to Fulfill FERC Order No. 693 Requirements: Restoration of Nuclear Power Plant Off-site Sources

EXHIBIT B – Restoration of Nuclear Power Plant Off-site Power Sources Data: 1st Quarter 2012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

MANDATORY RELIABILITY STANDARDS FOR THE BULK POWER SYSTEM	**)** **)**	**Docket No. RM06-16-000**

FIRST QUARTER 2012 COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO PARAGRAPH 629 OF ORDER No. 693

I. INTRODUCTION

In its March 16, 2007 Order,[1] the Federal Energy Regulatory Commission ("FERC" or "Commission") directed the North American Electric Reliability Corporation ("NERC") to provide a quarterly informational filing regarding the timeframe to restore power to the auxiliary power systems of U.S. nuclear power plants following a blackout as determined during simulations and drills of system restoration plans. This filing includes information for the first quarter of 2012.

[1] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *Order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[2]

Gerald W. Cauley
President and Chief Executive Officer
3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326-1001

David N. Cook*
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III. SUMMARY OF RESTORATION OF NUCLEAR POWER PLANT OFF-SITE POWER SOURCES DATA

Background

In response to comments offered by the U.S. Nuclear Regulatory Commission during the Notice of Proposed Rulemaking process, FERC expressed, in Order No. 693, its concern regarding the role and priority that nuclear power plants should have in bulk power system restoration plans. FERC addressed the concern in the discussion of the EOP-005-1 — System Restoration Plans Reliability Standard. Specifically, in Paragraph 629 of Order No. 693, FERC directed NERC as follows:

> The Commission directs the ERO to gather data, pursuant to §39.5(f) of the Commission's regulations, from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power

[2] Persons to be included on the FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.

EOP-005-1, Requirement R11 and sub-requirement R11.4 identify the expected priority for restoring off-site power to nuclear stations. They state:

> **R11.** Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.
>
> **R11.4.** The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.

Importantly, while the requirement provides the instruction to give high priority to off-site power restoration, it does not specify target timeframes.

The data presented in **Exhibit B** to this filing contain critical energy infrastructure information as that term is defined by FERC Rules of Practice and Procedure (18 C.F.R. Part 388), and the NERC Rules of Procedure. **Exhibit B** presents the raw data collected from nuclear generating stations through this period of observation. The information pertains to proprietary or business design information, including design information related to vulnerabilities of critical energy infrastructure information that is not publicly available. Accordingly, the information set forth in **Exhibit B** has been redacted from the public filing. In accordance with the FERC Rules of Practice and Procedure, 18 C.F.R. § 388.112, a non-public version of the information redacted from the public filing is being provided separately. NERC requests that the confidential, non-public information be provided special treatment in accordance with the above regulation.

The ERO data request for nuclear power plant off-site power source restoration data, as approved by the NERC Board of Trustees, is found in **Exhibit A**. Following NERC Board of Trustees approval, NERC began to collect nuclear data from U.S.

Transmission Operators during the fourth quarter 2007 and will continue to collect the data quarterly until otherwise directed by FERC. This filing represents data captured for the first quarter of 2012.

The specific data requested of the Transmission Operators requests the following information:

- Reporting entity;
- Name of exercise, drill or simulation;
- Date of exercise, drill or simulation;
- Name of nuclear plant;
- Unit designation (each unit must be included separately);
- Identifier of off-site power source;
- Time duration when off-site power sources are lost to the restoration of first off-site power source (For this request, the loss of off-site power sources is the simulated physical interruption of power in support of EOP-005-1 requirements); and
- Discussion of scenario assumptions or constraints impacting the restoration of the initial off-site power source to the nuclear power plant.

In addition, the following clarifying language was included in the data request to guide the Transmission Operators when supplying the requested data.

> Simulations, drills, or exercises that are implemented for individualized operator training requirements are not included in this request. Simulations, drills, and exercises conducted to support the requirements of EOP-005-1 are included in this request. This request is not intended to require additional simulations or studies to those conducted to satisfy EOP-005-1 requirements.

It is important to note that EOP-005 focuses on restoration plans and does not contain any requirement for restoration plans specific to nuclear plants. Hence, the reporting conducted under this data request so far will not result in a tabulation resulting in reports for each US nuclear plant.

NERC has not analyzed this data to identify the impact of the reported off-site power source restoration times relative to the ability of the U.S. nuclear power plants to remain in a mode that permits a timely return to service. NERC will utilize the information contained herein to ensure applicable entities are supporting their reliability standard obligations as defined in EOP-005-1 relative to the priority of off-site power source restoration to nuclear power plants in plans for system restoration.

Summary of Data

There are 104 nuclear units in the U.S. All of these units have reported the requested information as directed. In the first quarter of 2012, Transmission Operators conducted thirty-eight (38) individual exercises, drills, or simulations during this period that included the restoration of off-site power sources to fifty-seven (57) units, with many exercises, drills, or simulations impacting more than one nuclear unit.[3] Transmission Operators conduct these exercises, drills, and simulations in support of EOP-005-1 and report their results to their respective Regional Entities. The Regional Entities then report their findings to NERC.

In total, one hundred and eighty-five (185) off-site power source restoration "events" are included in the raw data presented in **Exhibit B** of this filing. Of the one hundred and eighty-five (185) events, there were one hundred eleven (111)[4] potential initial off-site source restorations (some units have multiple off-site sources). NERC

[3] For example, an entity conducted one system restoration exercise on June 10, 2011 that involved the restoration of offsite power sources to two nuclear units. In the summary chart that follows below, each offsite power source restoration "event" is reported separately for purposes of data analysis.

[4] Not all units provided data for off-site sources beyond the first source restored. The data included represents only the units that provided the data and does not include the entire spectrum of off-site sources beyond the initial source for the rest of the units.

categorized the restoration of first off-site sources in two-hour windows. Forty-nine (49) percent (54 of 111) of the initial off-site power source restorations occurred within the first two hours following the simulated blackout event, with over seventy-six (76) percent (84 of 111) occurring in four hours or less. Thirty (30) sources were simulated to be restored in the 2 to 4 hour window. One (1) source was simulated to be restored in the 4 to 6 hour window with an additional three (3) sources in the 6 to 8 hour window and one (1) source simulated in the 8 to 10 hour window. Twenty-two (22) sources did not have a restoration time reported.

Total Number Offsite Power Source Restoration Events Included in EOP-005-1 Exercises, Drills or Simulations	185
Potential first off-site source restorations	111
Exercises, Drills, or Simulations in which the first off-site source was restored in 2 hours or less following the loss of power	54
Exercises, Drills, or Simulations in which the first off-site source was restored 2-4 hours following the loss of power	30
Exercises, Drills, or Simulations in which the first off-site source was restored 4-6 hours following the loss of power	1
Exercises, Drills or Simulations in which the first off-site source was restored 6-8 hours following the loss of power	3
Exercises, Drills, or Simulations in which the first off-site source was restored 8-10 hours following the loss of power	1
Exercises, Drills or Simulations in which the first off-site source was restored more than 10 hours following the loss of power	0
Exercises, Drills, or Simulations that did not achieve the restoration of the first off-site power source to a nuclear power plant or that did not report a time for source restoration	22

The remaining seventy-four (74) events included in the data involved the restoration of a subsequent off-site source beyond the first source restored. Of the seventy-four (74) events, two (2) subsequent sources were simulated to be restored in two hours or less, eighteen (18) sources were simulated to be restored in the two to four hour window, one (1) source was simulated to be restored in the four to six hour window, and one (1) source was simulated to be restored in the six to eight hour window. The remainder of the subsequent sources (12) were restored in more than ten hours or did not have a time reported for restoration (40).

IV. CONCLUSION

NERC respectfully requests that FERC accept this informational filing for the first quarter of 2012 in accordance with FERC's directive that NERC provide information regarding the time it takes to restore off-site power sources to nuclear power plants following a blackout as determined by drills and simulations.

Respectfully submitted,

/s/ Andrew M. Dressel

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 31st day of May, 2012.

/s/ Andrew M. Dressel
Andrew M. Dressel
Attorney for North American Electric Reliability Corporation

Critical Energy Infrastructure Information Has Been Redacted From This Public Version

Exhibit A

Official Data Request to Fulfill FERC Order No. 693 Requirements: Restoration of Nuclear Power Plant Off-site Power Sources

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Gerry Adamski
Vice President and
Director of Standards

August 24, 2007

TRANSMISSION OPERATOR CONTACT
TITLE
COMPANY
ADDRESS
CITY, STATE ZIP CODE (TNR, 12pt)

Dear XXXXX:

Official Data Request to Fulfill FERC Order No. 693 Requirements
Restoration of Nuclear Power Plant Off-site Power Sources

Pursuant to the authority granted by FERC Order 672 and as implemented in Title 18, Section 39.2 of the Code of Federal Regulations, NERC as the appointed electric reliability organization issues this official data request as described in **Attachment 1**.

The legal basis in the United States for this authority is explained in FERC's Order 672, paragraph 114:

> 114. The Commission agrees with commenters that, to fulfill its obligations under this Final Rule, the ERO or a Regional Entity will need access to certain data from users, owners and operators of the Bulk-Power System. Further, the Commission will need access to such information as is necessary to fulfill its oversight and enforcement roles under the statute. Section 39.2 of the regulations will include the following requirement:
>
> > (d) Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity. The Electric Reliability Organization and each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

Within the United States, failure to comply with an official data request would constitute a violation of FERC regulations. Enforcement action is available to FERC to deal with violations of its regulations. This is authority FERC could exercise, not authority available to NERC. NERC's Compliance Monitoring and Enforcement Program, including the ability to impose penalties and sanctions, is limited to violations of reliability standards.

Please note the following additional pieces of information relative to this data request:

- An Excel spreadsheet (attached) to serve as a template for providing the requested information.
- Regional entities are requested to submit the requested information to sarcomm@nerc.net.

Thank you for your support of this effort. Please contact me should you have any questions.

Sincerely,



Enclosure

cc: James D. Castle, Chairman, Operating Reliability Subcommittee
Regional Entity Management Group

Exhibit A
Restoration of Nuclear Power Plant Offsite Power Source Data Request

Background
In paragraph 629 of Order No. 693, FERC directs NERC to provide an informational filing regarding the timeframe to restore auxiliary power to nuclear power plants following a blackout as determined during simulations and drills of system restoration plans:

> 629. "In addition the Commission directs the ERO to gather data, pursuant to § 39.5(f) of the Commission's regulations, from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis."

Description of Data Requested
This request is an ongoing request that begins in the fourth quarter of 2007. If an exercise, drill, or simulation includes the restoration of one or more offsite power sources to a nuclear power plant, the following information is to be prepared and provided *for each offsite power source* in a format developed and provided by NERC:

- Reporting entity
- Name of exercise, drill, or simulation
- Date of exercise, drill, or simulation
- Name of nuclear plant
- Unit designation (each unit must be included separately)
- Identifier of offsite power source
- Time duration when offsite power sources are lost to the restoration of first offsite power source. (For this request, the loss of offsite power sources is the simulated physical interruption of power in support of EOP-005-1 requirements.)
- Discussion of scenario assumptions or constraints impacting the restoration of the initial offsite power source to the nuclear power plant

Simulations, drills, or exercises that are implemented for individualized operator training requirements are not included in this request. Simulations, drills, and exercises conducted to support the requirements of EOP-005-1 are included in this request. This request is not intended to require additional simulations or studies to those conducted to satisfy EOP-005-1 requirements.

The individual data submissions should be submitted to the regional entity who will compile the data in a consolidated format. The regional entity will then forward the complied data to NERC's director of standards on a quarterly basis.

To comply with FERC directives, NERC will make a quarterly filing with FERC that includes the compiled data.

How the Data Will Be Used
The data will be provided to FERC per its directive in Order 693. FERC agrees with issues raised by the Nuclear Regulatory Commission (NRC) concerning the role and priority nuclear power plants should have in system restorations, and directs the collection of this data to aid in its review of this issue.

How the Data Will Be Collected and Validated
The regional entities are requested to coordinate the collection and composite presentation of the requested data from its member participants. Transmission operators responsive to this request are expected to validate the data to be correct prior to submittal.

Reporting Entities
Each transmission operator in the United States who has a nuclear power plant tied to a transmission line that it controls and who is participating in an exercise, drill, or simulation in support of the EOP-005-1 standard will report. Transmission operators that do not have a nuclear power plant tied to a transmission line it controls are exempt from this request.

Transmission operators outside the United States subject to EOP-005-1 are voluntarily encouraged to submit this information as well. NERC will seek permission from these non-U.S. entities for inclusion of its data in the information filed with FERC.

Due Date for the Information
If a transmission operator subject to this data request conducts a drill, simulation, or exercise that includes restoration of the initial offsite power source to a nuclear power plant, the transmission operator is to submit the requested information to its regional entity by the fifteenth of the month; following the end of the previous three-month quarter. The regional entity is to provide a quarterly report of all such submissions by April 30, July 31, October 31, and January 31 for the three-month period that concludes on these dates. This data request begins in the fourth quarter of 2007.

If no drill, exercise, or simulation meeting the criteria described above is conducted during a quarter, no submission by the transmission operator and regional entity is required. This data request does not direct transmission operators to conduct quarterly exercises, drills, or simulations to satisfy this data request. It does require the data to be reported if such a simulation, drill, or exercise is conducted.

Restrictions on Disseminating Data (Confidential/CEII)
NERC will provide this data to FERC per its Order No. 693 directives. This information will be treated as critical energy infrastructure information when submitted to FERC.

Estimate on Burden Imposed to Collect Data
There will be ongoing costs for the staff of responsible entities to respond and for regional entities to collect, compile, and report to NERC the requested data.

Exhibit B

Restoration of Nuclear Power Plant Off-site Source Data: 1st Quarter 2012

Critical Energy Infrastructure Information Has Been Redacted From This Public Version

139 FERC ¶ 61,168
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

North American Electric Reliability Corporation Docket Nos. RC11-6-001

ORDER GRANTING IN PART, AND DENYING IN PART, CLARIFICATION AND DENYING REHEARING

(Issued May 31, 2012)

1. On March 15, 2012, the Commission accepted, with limited conditions, the petition of the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), requesting approval of its proposal to make informational filings in a "Find, Fix, Track and Report" (FFT) spreadsheet format of lesser-risk, remediated possible violations of Reliability Standards.[1] NERC requests clarification or, in the alternative, rehearing, of the March 2012 Order. In this order, we grant in part, and deny in part, NERC's request for clarification, and deny the alternative request for rehearing.

I. Background

2. On September 30, 2011, NERC filed a petition requesting approval of its proposal to make informational filings in a FFT spreadsheet format of lesser-risk, remediated possible violations of Reliability Standards. NERC explained that the processing of possible violations in the FFT format would provide NERC with greater flexibility and efficiency in its compliance program, so that NERC can focus its resources on the matters that pose a more serious threat to Bulk-Power System reliability. A possible violation addressed through an FFT informational filing is not subject to a penalty, but counts as part of the registered entity's compliance history. NERC also stated that a registered

[1] *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 (2012) (March 2012 Order).

entity must provide a statement that a possible violation is mitigated before the matter is submitted to the Commission in an FFT informational filing.[2]

3. In the March 2012 Order, the Commission accepted, with limited conditions, NERC's FFT petition. The Commission also directed NERC to submit a compliance filing within sixty days and submit two informational filings. With regard to NERC's proposal that a registered entity provide a statement that a potential violation has been mitigated, the Commission set the following condition:

> To ensure effective remediation of possible violations accorded FFT treatment, we accept NERC's proposal to require a registered entity to submit to its Regional Entity a statement certifying that remediation has occurred and is completed. We will require that a registered entity submit to the Regional Entity an affidavit, signed by an officer with knowledge of the remediation, certifying that the statement is true and correct.[3]

II. NERC Request for Clarification or, in the Alternative, Rehearing

4. NERC requests that the Commission clarify "that it did not intend to limit the ability of registered entities to designate appropriate signatories for the certification of mitigation activities associated with remediated issues to officers of the registered entity."[4] NERC states that certain registered entities, such as public power utilities that are political subdivisions of a state, might become ineligible for the FFT program because they have no officers. NERC also contends that placing a higher burden for certification is inconsistent with the goals of the FFT program.

5. NERC seeks clarification that a certification of remediation can be submitted by an officer, employee, or other authorized representative of the registered entity with knowledge of the remediation. According to NERC, absent such clarification, the March 2012 Order would be inconsistent with - and create a greater burden than - NERC's Compliance Monitoring and Enforcement Program (CMEP), which provides that "[a]ny report or other submission of information by a Registered Entity required by the Compliance Program shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity. ... NERC or the Compliance Enforcement Authority may require the signer to provide a statement of the basis of his or her authority to sign on behalf of the Registered Entity." NERC states that this

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[2] September 30, 2011, NERC Petition at 3.

[3] March 2012 Order, 138 FERC ¶ 61,193 at P 61 (footnote omitted).

[4] NERC clarification request at 2.

provision of the CMEP was developed as the result of a Commission order, in lieu of more restrictive language initially proposed by NERC.[5]

6. In the alternative, NERC seeks rehearing of the March 2012 Order. Specifically, NERC contends that the Commission erred in limiting the scope of potential signatories for certifications of mitigation activities associated with remediated issues filed through FFTs in contravention of the CMEP and the Commission's prior orders on this issue. NERC argues that, with respect to this issue, FERC has failed to properly support its finding and, therefore, failed to engage in reasoned decision-making.

III. Discussion

7. We grant, in part, NERC's request for clarification of the March 2012 Order. We conditioned our acceptance of NERC's proposal on the requirement that a registered entity submit to its Regional Entity a statement certifying that remediation has occurred and is completed, and that a registered entity submit to the Regional Entity an affidavit, signed by an officer with knowledge of the remediation, certifying that the statement is true and correct.[6] Our intent was to ensure that compliance matters that are processed through the FFT mechanism are brought to the attention of senior officials of the registered entity, not to preclude the participation of registered entities that are not organized as corporations. Accordingly, we clarify that a registered entity that is not organized as a corporation or has no officers may submit an affidavit certifying mitigation to the Regional Entity signed by a person in an executive or leadership position with knowledge of the remediation equivalent to that of an officer.

8. However, we deny NERC's request to the extent that NERC seeks to broaden the potential signatories who can certify that mitigation is complete to officers, employees or other authorized representatives of any registered entity. NERC contends that the condition in the March 2012 Order is a departure from the language of NERC's CMEP and related Commission precedent. However, neither NERC's CMEP nor the Commission precedent cited by NERC address - or even contemplate - the new FFT format for processing possible violations. We believe that a more stringent certification requirement is justified in the context of verifying mitigation of a possible violation of a matter resolved through the FFT process. Requiring verification of mitigation by a corporate officer or equivalent for eligibility for FFT treatment, as clarified herein, assures that appropriate senior personnel within a registered entity are made aware of possible violations and have personal knowledge that they are mitigated.

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[5] NERC clarification request at 3-4 (*citing North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, at PP 197-198 (2007)).

[6] March 2012 Order, 138 FERC ¶ 61,193 at P 61.

9. Accordingly, we grant NERC's request for clarification in part, and deny clarification in part, as discussed above. We also deny NERC's request for rehearing for the reasons discussed above.

The Commission orders:

The Commission hereby grants clarification in part, and denies clarification in part, and denies rehearing, as set forth in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	)))	Docket No. RC11-6-___

COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation ("NERC") submits this filing in compliance with the order of the Federal Energy Regulatory Commission ("FERC" or "Commission") in *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 (2012) ("March 15 Order").[1] In the March 15 Order, among other things, the Commission accepted, with limited conditions, NERC's petition requesting approval of its proposal to make informational filings in a Find, Fix, Track and Report ("FFT") spreadsheet format of minimal risk, remediated possible violations of Reliability Standards.

I. Introduction

NERC launched the Compliance Enforcement Initiative ("CEI") in September 2011 as part of the organization's broader efforts on reliability excellence.[2] This objective is manifested in other efforts throughout the organization, particularly those related to the identification of reliability priorities. NERC has the requisite expertise and responsibility to systematically identify reliability priorities and address them effectively and efficiently. NERC's prioritization

[1] NERC is also submitting today, in this docket, the first of two information reports required by the Commission in the March 15 Order. On March 15, 2013, NERC will submit the twelve-month implementation report and compliance filing as directed in the March 15 Order.

[2] The two improvements introduced were an abbreviated reporting format for Notices of Penalty ("NOP") in the form of a spreadsheet, Spreadsheet NOP ("SNOP"), and the FFT.

efforts are based on NERC's expert knowledge of the bulk power system and related risks. As indicated in the Petition, all instances of noncompliance, whether large or small should be identified, corrected and reported. In the March 15 Order, the Commission has endorsed the use of different enforcement tracks for issues posing different levels of risk to the reliability of the bulk power system ("BPS"). The CEI has been instrumental in allowing NERC and the Regional Entities to differentiate the processing of issues based on the level of risk posed to the reliability of the BPS.

As directed by the Commission, this Compliance Filing focuses on two issues: (a) the impact of a registered entity's compliance history in the determination of whether FFT treatment is appropriate in a given situation and (b) NERC's plans for future implementation of the CEI, including continuing training and outreach efforts to ensure the sustainability and expansion of the program as well as the efforts to ensure consistency and due process.

II. The Sustainability and Expandability of the CEI and Guiding Principles

The CEI filing introduced a new paradigm in enforcement. NERC and the Regional Entities are increasing the utilization of their inherent enforcement discretion in the implementation of compliance and enforcement activities. The CEI filing set forth a more comprehensive and integrated risk control strategy that differentiates and addresses compliance issues according to their significance to the reliability of the BPS. The basic tenets are simple: (1) minimal risk issues do not require the same amount of time and resources as more serious risk issues, and (2) prompt attention and more time and resources should be devoted to more serious risk issues, including proactive steps to identify and mitigate potential risks rather than reacting to noncompliance. While NERC originally proposed that there would be a discrete Phase I and

Phase II implementation, through experience gained to date, NERC believes the proper focus is on ensuring the sustainability and expandability of the CEI program. This means that there is no going back to the prior model, and work must continue to expand the effectiveness of the current FERC-approved program. The first step in the expansion of the program is to have recommendations from compliance monitoring staff regarding the disposition of certain possible violations as FFTs. Future steps are currently being considered and will be addressed in NERC's upcoming twelve-month report. These future steps will be developed with the input and participation of Regional Entities and industry stakeholders.

Ongoing and consistent training is paramount to both the sustainability and expandability of the program, as discussed in more detail below. As also discussed, training is one of the tools which are used to support and drive consistency and due process.

With the March 15 Order, significant strides have been gained in ensuring that there is no one size fits all approach to resolving possible violations. The March 15 Order further invited NERC, Regional Entities and the industry to consider additional opportunities to focus on risk, including identification of Reliability Standard requirements that may not be needed or that require modification. NERC commends the Commission for this forward-looking objective. NERC is pleased to report that efforts are underway and will be the subject of a different filing at the appropriate time.

Sustainability of the program requires that there be consistency in application. NERC intends to promote consistency through a series of training and outreach sessions for Regional Entity enforcement and compliance staff on the identification and disposition of possible violations as FFTs. For the last five years, NERC and the Regional Entities have gained significant experience in conducting risk assessments. Over 3,100 violations have been processed as notices of penalty. Nearly 450 FFTs have been processed as of March 30, 2012.

This provides a useful library of examples not only of a risk assessment but of mitigating activities to correct and prevent recurrence of violations. For ease of reference, consolidated spreadsheets of FFTs and NOPs are publicly available on NERC's website.[3] This experience forms the basis for the training that is underway and to be implemented.

The existing guidance in the initial CEI filing, the March 15th Order guidance on risk assessments and actual FFT examples are training tools for enforcement staff and compliance monitoring staff that will ensure the exercise of discretion remains focused on meeting the purpose of the FFT program. In addition to training, oversight of the CEA staff will play a key role in assuring discretion is consistently applied.

NERC will also seek to expand the application of the FFT process. Expandability not only applies to who may identify potential FFT issues but also an expansion of the effectiveness of the program. The initial domain of usage involved CEA enforcement staff. NERC believes there is value in identification of minimal risk issues as early as possible. At this stage, CEA compliance monitoring staff will not make FFT determinations; rather, they will make recommendations to enforcement staff. NERC and the Regional Entities will continue to explore opportunities to enhance the roles of both CEA compliance monitoring and enforcement staff in the identification of potential FFT candidates.

Compliance monitoring staff may continue to provide guidance to the registered entity on appropriate mitigation activities while on site. Faster identification and application of mitigation activities will result in improved reliability and additional minimal risk possible violations that, having been mitigated early on, may qualify for FFT treatment. Enforcement staff will continue

[3] See http://www.nerc.com/filez/enforcement/index.html.

to have a key role in approval of final mitigation activities to ensure consistency within and among the Regional Entities.

CEI process enhancements will be made through gradual but continuous improvements, based upon the knowledge and experience gained by Regional Entities and NERC as they realize increased efficiencies through improved and expanded processes. A significant degree of flexibility will allow Regional Entities to continuously improve the program subject to NERC oversight.

II. Compliance History as a Factor in Considering FFT Treatment

In the March 15 Order, FERC accepted NERC's proposal to "count a possible violation processed as an FFT matter as part of the registered entity's compliance history." FERC explained that:

> Registered entities are not obligated to have a matter resolved through an FFT informational filing. If a registered entity does not wish a possible violation to be included in its compliance history, it may opt to use the CMEP processes otherwise available to seek a dismissal of the possible violation or an on-the-record determination that it did not violate a Reliability Standard.[4]

However, FERC requested additional clarification on:

> how a remediated issue will be factored into a registered entity's compliance history going forward. For example, possible violations of individual Reliability Standard requirements may pose a lesser risk when considered in isolation, but pose a higher risk in the context of other violations, whether reported in the same FFT filing, another FFT filing, or a Notice of Penalty. Alternatively, analysis of a poor compliance history may reveal, for example, shortcomings in the registered entity's training programs rather than the lack of a culture of compliance.[5]

As a result, FERC directed NERC:

[4] March 15 Order at P 63.
[5] March 15 Order at P 64.

> to submit within sixty days from the date of this order a compliance filing explaining the principles it will employ in evaluating an entity's compliance history. In its sixty-day compliance filing, NERC should include an explanation of how it will determine that an entity's compliance history is a contributing factor to the entity receiving FFT treatment for a possible violation. The sixty-day compliance filing should also include examples of where an entity's compliance history precludes or is a strong factor against an entity receiving FFT treatment for a possible violation. NERC should also explain in the sixty-day compliance filing the principles it will use to evaluate an entity's compliance history with respect to the following specific issues: self reports, repeat remediated issues, and multiple remediated issues arising from a single incident. We do not require NERC to explain in each monthly FFT spreadsheet filing how a registered entity's compliance history was factored into the remediated issues reported."[6]

These are addressed in turn, below.

A. Principles Regarding Compliance History

An entity's compliance history, including prior or repeat issues by the entity or its affiliates, the entity's internal compliance program, internal controls and culture of compliance, are factors that have been and will continue to be taken into account in determining whether FFT treatment is warranted in any given case, and will be referenced in the FFT spreadsheet as appropriate. This is consistent with the Commission's requirement that "[i]n considering the seriousness of a violation, one factor evaluated by the Commission is whether a violation is a repeat offense or if the company has a history of violations."[7] This is also consistent with the NERC Sanction Guidelines, which provide that "[i]f a violator has had repetitive infractions of the same or a closely-related reliability standard requirement, particularly within a time frame defined within the standard(s) or deemed appropriate by NERC or the regional entity in the absence of the standard(s) defining the time frame, NERC or the regional entity shall consider some increase to the penalty." The NERC Sanction Guidelines also provides that "a violation

[6] March 15 Order at P 66 (footnote omitted).
[7] *North American Electric Reliability Corporation*, 132 FERC ¶ 61,182 (2010) at P 5, *citing* Revised Policy Statement on Enforcement, 123 FERC ¶ 61,156, at P 55 (2008).

history of no violations will produce no mitigation of the Penalty otherwise determined; a violation history of infrequent minor violations of lesser risk Requirements assessed lower Violation Severity Levels may result in small or no increase; a history of more frequent violations or previous violations of higher risk Requirements assessed more severe Violation Severity Levels will generally incur commensurately larger increases." Although there are no penalties applied to FFT remediated issues, the corresponding effect of the "aggravation" would be to result in a factor weighing against FFT treatment to a particular matter.

The Commission has explained that the factors of a prior violation need not be identical to a current violation to constitute an aggravating factor.[8] The Commission has stated that the reference, in the NERC Sanction Guidelines to "repetitive infractions" include: 1) repeated or continuing examples of conduct similar to that underlying the prior violation of the same or a closely-related Reliability Standard Requirement; 2) conduct addressed in a registered entity's previously submitted mitigation plan for a prior violation of the same or a closely-related Reliability Standard Requirement; or 3) multiple violations of the same Standard and Requirement.[9] The evaluation of an entity's compliance history includes the consideration of whether "instant violations may reflect recurring conduct by the same registered entity or by an affiliate or department that is operated by the same corporate entity or whose compliance activities may be conducted by that entity" as well as consideration of prior violations by the same or affiliated entity made by different Regional Entities.[10]

In applying these principles, NERC and the Regional Entities will continue to determine, based on the particular facts of each violation/remediated issue, whether a prior

[8] *Id.*
[9] *Id.*
[10] *Id.* at P 7.

violation/remediated issue of the same or a closely-related Reliability Standard should preclude FFT treatment.[11]

1. Repeat Violations Do Not Necessarily Preclude FFT Consideration

As indicated in the Petition, repeat issues are eligible for FFT treatment, provided that the issues pose only a minimal risk to reliability of the BPS. However, the identification of repeat issues of same, similar or different Reliability Standards may lead the CEA to use its discretion to discontinue the use of the FFT process and escalate the processing of these issues as possible violations as described in the CMEP.

An entity's compliance history must be considered in context. A large number of violations or remediated issues in an entity's compliance history could reflect an aggressive compliance program or could be evidence of a systemic problem, either related to the company's culture of compliance, the effectiveness of its compliance program or the effectiveness of its internal training, depending on the underlying facts and circumstances. Accordingly, there is no one-size-fits-all formulaic approach. NERC and the Regional Entities will continue to evaluate an entity's entire compliance history in order to determine the appropriate enforcement track for a particular matter. Issues to be considered include, but are not limited to:

- The timing of the prior and instant violations/remediated issues.

As a general matter, the fact that an entity has prior violations/remediated issues which occurred in the early years of mandatory and enforceable Reliability Standards may be a factor in favor of affording FFT treatment to a subsequent matter.

- The nature, scope and risk of the prior and instant violations/remediated issues.

[11] *Id.* at P 8.

Depending particularly on the level of risk posed by the violations/remediated issues that comprise the entity's compliance history, FFT treatment may still be warranted for new minimal risk issues.

- Whether the prior and instant violations/remediated issues have been self-identified and/or indicate a robust compliance program.

As a general matter, self-reports and other forms of self-identified issues will be one of the factors that may weigh in favor of affording FFT treatment for repeat issues.

Thus, if the registered entity's compliance history evidences a dedication to complying with NERC standards, FFT treatment reinforces and rewards that behavior by addressing minimal risk, mitigated compliance issues in an efficient manner. FFT treatment will reinforce a culture of compliance where the registered entity has, for example, a history of timely responses to Regional Entity requests, including a registered entity's internal compliance assessments especially following significant system events; prompt self-reports; and full and timely correction, in accordance with approved mitigation plans, of prior violations.

FFTs related to repeat issues have been submitted and will continue to be submitted where the conduct does not signal a broader concern or a failure of the mitigation of the prior issue. This could be the case, for example, if the new issue has different facts, or occurs in a portion of the company not covered by the prior mitigation efforts. It has also occurred in the context of multiple violations within the same corporate family when several affiliated registered entities utilize a common document in compliance with specific Reliability Standards. In those cases, the identification of a problem in a corporate-wide document may result in violations for each of the affiliated registered entities, even though there is only a single instance or event that

constitutes the basis of the noncompliance. Provided that the risk assessment indicates a minimal risk, the existence of the multiple violations would not alone preclude FFT treatment.

In addition, there may be situations in which possible violations are identified at one time either because they were discovered at the same time or because they arise or result from a single incident. As a general matter, all past and pending possible violations are evaluated in the course of determining the ultimate filing format and disposition. While they will generally be filed together, the timing of completion of mitigation may affect when individual possible violations are filed. In cases where a possible violation is filed separately from others that were discovered at the same time or resulted from a single incident, NERC and the Regional Entities will continue to evaluate the totality of the registered entity's compliance history in order to identify any broader corporate or compliance issues.

B. Examples of Repeat Issues that Would Not be Afforded FFT Treatment

FFT candidates are considered both in isolation and in the aggregate to determine whether there is a systemic or performance failure on the part of the registered entity. This is the case with respect to multiple violations/remediated issues filed concomitantly as well as an entity's prior compliance history. NERC and the Regional Entities have rejected and continue to reject FFT candidates where the registered entity's compliance history is indicative of broader concerns either due to the number of repeat issues or the seriousness of such issues. In certain cases, evidence of a lack of commitment of senior management to the entity's compliance program, associated with a large number of prior violations resulted in a rejection of FFT treatment for additional violations.

Where the registered entity's compliance history reveals a pattern of disregard of NERC requirements, the failure to impose a penalty might not sufficiently deter such behavior and

promote compliance efforts. This could be evidenced by (a) a registered entity's pattern of failure to respond to Regional Entity requests, or to complete prior mitigation plans on time without seeking extensions in accordance with the CMEP; (b) a Regional Entity's inability to confirm mitigation plan completions certified by the registered entity; or (c) continued repetitions of the same violations in a manner that indicates or evidences a lack of internal controls to prevent recurrence/inadequate mitigation of earlier violations. In addition, compliance history would argue against FFT treatment if it shows a pattern of lack of concern about reliability compliance, indicating that imposing a penalty on the registered entity even for minimal risk violations serves an important purpose in promoting that entity's compliance.

As required by the Commission in the March 15 Order, FFT treatment would not be afforded to a prior remediated issue that was subsequently found not to have been mitigated. Similarly, cases involving material misrepresentations about the nature and scope of the prior issue would preclude FFT treatment.[12]

IV. Future CEI Implementation

NERC recognizes that we are in the early stages of implementation of CEI. The March 15 Order provided the cornerstone upon which the program will continue to be implemented and to evolve. In the March 15 Order, FERC authorized NERC to proceed with the implementation of the CEI but requested clarification regarding "how Regional Entity audit teams will decide

[12] As stated in the March 15 Order, "the Commission retains the discretion to review a possible violation reported in an FFT informational filing even after the sixty day period if it finds that FFT treatment was obtained based on a material misrepresentation of the facts underlying the FFT matter." March 15 Order at P 72.

whether a possible violation will be resolved through the CMEP or FFT processes and how NERC will achieve consistency of outcomes."[13]

Specifically, FERC made the following requests for information:

- Describe how NERC and Regional Entity compliance and enforcement personnel will be trained to implement Phase II and, for informational purposes, provide copies of any training materials prepared for this purpose;
- Explain the procedures for coordination and collaboration between compliance personnel and enforcement personnel in evaluating FFT eligibility during Phase II;
- Explain how NERC intends to obtain consistent treatment of possible violations for FFT treatment among the Regional Entities and as between NERC and the Regional Entities; and
- Describe the process for certification or qualification of specific personnel to participate in eligibility determinations during Phase II.

The following sections respond to these requests for information and address NERC's plans for future implementation of the CEI, including through the continuing training and outreach efforts described below.

A. Training and Outreach Activities

1. Training and Outreach Opportunities since September 2011

To support the implementation of the CEI, NERC held a series of webinar, workshop and training opportunities for both Regional Entities and registered entities. These activities provided information to the Regional Entities and industry regarding the FFT process and progress. During the first several months of the CEI, nearly 1,500 attendees, including Regional Entity and registered entity representatives, participated in the NERC workshops, webinars and training sessions related to the CEI. Attachment A to this filing includes a report on all training

[13] March 15 Order at P 80.

and outreach activities conducted for both Regional Entities and registered entities including venue, agenda and key points and target audience.[14]

NERC and the Regional Entities continue to conduct informational webinars for both Regional Entity staff and industry stakeholders. Webinars have focused on lessons learned from discovery and processing of FFTs, including the importance of internal compliance programs to identify potential violations of reliability standards, appropriate risk assessments, and completion of mitigation activities. Webinars for industry also have focused and will continue to focus on case study examples of FFTs filed. In addition, industry and ERO general workshops continue to include sessions on CEI progress and lessons learned and the importance of the CEI in promoting reliability and accountability.

In addition to these ERO-conducted training opportunities, NERC staff participated in other events to discuss the CEI in general and FFT in particular. These opportunities are also listed in Attachment A.

2. CEA Staff Training

In addition to more general training and outreach activities referenced above, additional specific CEI training will be provided to CEA staff, including compliance monitoring and enforcement staff, to ensure successful implementation of the program in the field, promote consistency and ensure processes, roles, and responsibilities are well understood.

All CEA staff, including compliance monitoring staff and enforcement staff, will be trained with respect to the ongoing implementation of FFT. This will ensure consistency within and among the CEA staffs. The focus of the training will be on evaluation of the underlying facts

[14] Selected presentations and other materials are available at http://www.nerc.com/page.php?cid=3|22.

and circumstances, assessment of the risk, evaluation of the corrective and preventive actions and consideration of compliance history and other relevant factors. Training also will focus on application of the factors to be considered in connection with FFT treatment and risk assessments illustrated by case studies of FFTs filed since September 2011 and informed by the March 15 Order. The respective roles of compliance monitoring and enforcement staff with respect to identification and recommendation of FFT candidates and coordination and collaboration between these functions will also be part of the training sessions. The outline of training to be provided to CEA staff is attached as Attachment B.

CEA staff training will continue through the third and fourth quarters of 2012. NERC, in conjunction with the Regional Entities, will develop training materials for CEA staff in order to ensure the appropriate qualification of personnel who will be responsible for making FFT determinations. Lead Auditor training taking place in May, August and October, 2012 will address the accumulation of information necessary for assessing risk and deciding whether FFT treatment is appropriate. This training will also cover interpersonal communication and conflict management.

Webinars and web modules providing education for CEA compliance and enforcement staff will be available in August, 2012. These training tools will include case studies with examples of violations that are appropriate for FFT treatment and violations that are not appropriate. The examples will cover Operations/Planning Standards and CIP Standards, with the purpose of expanding CEA staff skills to evaluate and assess risk. This qualification process will be ongoing, with the goal of qualifying great enough percentages of CEA personnel to implement FFT determinations in the field in early 2013.

B. Coordination and Collaboration between Compliance Monitoring and Enforcement Personnel

To ensure coordination and collaboration between compliance monitoring and enforcement staff, it is critical that these individuals understand their respective roles in the continued implementation of CEI. These roles, summarized below, reflect the early stages of implementation of the CEI. At this time, with the appropriate training, compliance monitoring staff will make recommendations to enforcement staff. This provides a check and balance system and will facilitate consistency and due process. Some Regional Entities are already implementing this successfully.

As experience is gained, and capabilities are developed, we expect to continue to evolve the roles to ensure the continued success of the program. The ultimate objective of expanding this aspect of the program is to allow for the identification and final resolution of minimal risk issues, including mitigating activities, at the earliest possible opportunity. The process of developing next steps will include the input and participation by Regional Entities and industry stakeholders.

1. Identifying and Processing FFTs in Connection with Compliance Audits, Spot Checks and Compliance Investigations

Compliance Audit, Spot Check and Compliance Investigation findings will continue to be made as they were prior to the implementation of the CEI. At this time, NERC is not proposing that the FFT decision will be made and communicated to the registered entity on site. Rather, following conclusion of the compliance monitoring activity, compliance monitoring staff will promptly communicate an FFT recommendation to enforcement. Enforcement will then conduct a preliminary review of the FFT candidate to confirm consistency and completion of all FFT requirements, and will then promptly issue the Notice of Possible Violation and send the FFT opt

out letter to the registered entity. If the entity does not elect to opt out of FFT processing, enforcement will then promptly submit the FFT spreadsheet to NERC. However, even if compliance monitoring staff does not make a recommendation that a possible violation is an FFT candidate, enforcement will still continue to review all possible violations and afford FFT treatment where appropriate to ensure consistency and fairness. As experience is gained, this aspect of implementation will continue to evolve.

In considering whether to recommend FFT treatment, compliance monitoring staff may obtain, as necessary, any background information necessary to effectively apply the factors to be considered in identifying FFT candidates (e.g., compliance history). Additional information from the registered entity may be required and obtained as part of the consideration of whether to recommend FFT treatment (e.g., compliance plans, internal controls etc.). The Guidance for Self Reports available on the NERC web page should be used as guidance for the nature and scope of the information to be obtained from the registered entity.

2. Other Compliance Monitoring Activities

Enforcement staff will continue to evaluate FFT candidates identified through all monitoring methods, but will have principal responsibility for identifying FFT candidates that have not been recommended by an auditor or investigator. With respect to FFT candidates recommended by auditors or investigators, enforcement staff will review the record for completeness and will request additional information as necessary.

C. Consistency and Due Process

Given the number of factors taken into account when determining the appropriate enforcement track for a specific issue, even if two situations appear the same or similar on the

surface these factors may drive different results. Consistency is driven by (1) having appropriate policies, procedures and oversight controls in place, (2) ongoing vetting of candidates prior to ultimate disposition by NERC and the Regional Entities, (3) after the fact peer review of a sample of FFT candidates that have been filed or rejected, and (4) training.

NERC and the Regional Entities follow common processes and consider the same factors in the determination of the appropriate enforcement track of any possible violation. For example, NERC and the Regional Entities utilize common forms, letters and spreadsheets to promote consistency in processing issues. The factors considered in identifying FFT candidates were discussed in the Petition and the Commission's March 15 Order. They include (1) minimal risk to reliability[15] and related facts and circumstances, including what happened, why, where and when, including the timeframe for and completion of mitigation, (2) Reliability Standard at issue and applicable Violation Risk Factor (VRF) and Violation Severity Level (VSL), and (3) Registered Entity's compliance program and compliance history.

With respect to oversight controls, CEA enforcement will have oversight over FFT recommendations made by compliance monitoring staff. In addition, NERC exercises review and oversight to ensure consistent treatment of matters.

NERC reviews all possible violations for comparison against possible violations that have already been processed, regardless of the enforcement processing track they will follow. Possible violations involving similar facts and circumstances or similar Reliability Standard or Requirements are closely reviewed to ensure the respective outcomes are consistent (even if not identical). While the existing precedent informs NERC's review of new possible violations,

[15] Although certain moderate risk FFTs were filed between September 2011 and February 2012, in accordance with the FERC order issued on March 15, 2012, only minimal risk issues will be included prospectively.

NERC also reviews any applicable settlement agreements, mitigation plans and proposed penalties in order to promote consistency among the Regional Entities. There is also constant communication among NERC and the Regional Entity's compliance and enforcement staffs to ensure alignment of expectations and consistency with respect to how matters are evaluated and processed. The Commission itself recognized the benefits of conducting sampling to make sure the program is working. NERC and the Regional Entities also will develop a process for sampling of FFT candidates to ensure the program is working as intended.

NERC and the Regional Entities also ensure that requisite information is made available, at the time of the filing of an issue with FERC, to allow third parties to understand, after the fact, what factors were relevant in the review of each case. Whether an issue is processed as an FFT or Spreadsheet NOP, the description, risk assessment and mitigating activities are appropriately scaled.[16] This information allows third parties to compare issues and understand outcomes which may appear to be disparate at a first glance.

NERC and the Regional Entities are always seeking to improve the transparency and availability of information. Searchable spreadsheets for both FFTs and Spreadsheet NOPs are available on the NERC website[17] and provide faster dissemination of information and more transparency in results. That format also helps NERC, Regional Entities and industry stakeholders identify potential consistency issues that need to be addressed.

Ongoing CEA staff training and guidance both with respect to the criteria for identifying FFTs and the process steps to be taken in connection with the identification and processing of

[16] As part of the review process referenced above, NERC examines each and every NOP and FFT candidate prior to filing to ensure that the filing contains a robust discussion of these issues, as well as the actual and potential risk and any interim protections that may have mitigated the risk.
[17] See http://www.nerc.com/filez/enforcement/index.html.

FFTs also will further promote consistency in implementation of the CEI. NERC and Regional Entities pay particular attention to consistency in outcomes and due process and will realign as necessary. However, as noted, consistent approaches do not necessarily equate to identical outcomes.

D. Qualification of Personnel

CEA compliance monitoring and enforcement staff engaged in the disposition of possible violations will be required to successfully complete the CEA staff training in development and as described herein. Training will be conducted in accordance with generally accepted training practices following the outline in Attachment B. NERC and the Regional Entities will keep training records of its own staff and will require training by all relevant staff. Continuing training will be available to all CEA staff on a pre-determined timeframe.

V. Conclusion

NERC is committed to the sustainability and future expansion of the CEI and will take all necessary actions to ensure the continued success of the program, as evidenced in the discussion of the applicable processes and the ongoing training and outreach efforts, including future training and certification of CEA staff. In conclusion, NERC requests that the Commission accept this submittal in compliance with the March 15 Order.

Respectfully submitted,

/s/ Rebecca J. Michael

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Dated: May 14, 2012

Attachment A

Training Opportunities since September 2011

I. NERC-sponsored Activities

In September 2011, NERC conducted the Fall ERO Auditor Workshop in Atlanta, GA. This multi-day workshop was conducted for compliance staff from each Regional Entity and NERC. The purpose of the ERO Auditor Workshop is to provide auditors with CMEP information and updates and to promote consistency in the application of the program and audit practices across the industry. The workshop included presentations, panel discussions, and breakout work sessions to provide auditors the opportunity for interactive involvement and continuing training. Included in the agenda was a session presented by NERC enforcement staff on the CEI. The session included discussions on the background and development of the FFT process, purpose of the CEI, the implementation plan, considerations for assessing potential violations for FFT treatment including assessment of risk, reporting mechanisms and key roles. The session included opportunities for questions and discussion. Approximately 65 compliance enforcement authority ("CEA") staff attended.

On October 6, 2011 a Regional Entity webinar was conducted by NERC staff. Participants included Regional Entity staff in the compliance and enforcement programs. The webinar covered the following key points: The CEI represents a risk-informed approach that draws upon experience and technical expertise to promote the reliability of the BPS. The new enforcement initiative is designed to concentrate attention and efforts of registered entities, Regional Entities, and NERC on possible violations in proportion to the significance of their actual or potential risks to reliability of the BPS, eliminate undue administrative and regulatory burdens on registered entities that do not result in reliability benefits, streamline paperwork

requirements, and encourage continued timely and thorough self-reporting and mitigation. By identifying, mitigating and resolving on a streamlined basis the possible violations that pose a minimal risk to reliability of the BPS, more time, resources and efforts can be devoted to more significant possible violations. Implementation of the CEI will facilitate more efficient and effective risk management. The webinar included questions and discussions among the presenters and participants. Approximately 29 staff participated in the webinar.

On October 13, 2011, a webinar was conducted for NERC members and industry stakeholders on the CEI. Introductory comments were provided by the NERC CEO. The key points covered were similar to those presented in the October 6 webinar. The agenda included background information, the phased implementation plan, spreadsheet notices of penalty, how FFTs would be identified including risk significance and mitigation activities taken by the entity, and FFT examples. The webinar included questions and discussions among the presenters and participants. Approximately 245 industry representatives participated in the webinar.

In addition, NERC conducts quarterly training sessions for Audit Team Leaders. Beginning with the November 2011 class, a session was added to the course agenda to discuss the CEI. The items covered in the session included the background and purpose of the CEI, Spreadsheet NOPs, FFT process and examples, CEI filing and status CEI implementation timeline, and audit team actions. A similar session was conducted in February 2012. This training will be updated with current information, examples, and CEI status for future sessions. Approximately 10 to 20 audit team leaders participate in each training session.

In November 2011, a CEI workshop was conducted at NERC in Atlanta for Regional Entity CEA staff. The purpose of the workshop was to provide Regional Managers and Staff

with CEI information and updates; promote consistency in the application of the CEI in order to enhance the consistency of audit practices across the industry; and capture feedback to enable the ERO and Regional Staff to develop more granular guidance to both enhance consistency and support the development of the CEI and training programs. The workshop included presentations, discussions, and working sessions to provide Regional Managers and Staff the opportunity for interactive involvement, discussion and training. Topics included review of CEI status, detailed discussions of FFT processes and examples and lessons learned from the early FFT submittals. Approximately 20 staff attended the workshop.

In December 2011, several training activities were conducted. On December 6, a Compliance Workshop for industry representatives included a session presented by NERC staff on the CEI. Participants were registered entity compliance staff. The session included discussion of the CEI background and purposes, filing status, spreadsheet notices of penalty, FFT examples, statistics summary and guidance for self-reporting. Also presented were factors for consideration including risk and mitigation actions. Approximately 204 industry representatives participated in the workshop.

On December 12, 2011, a Regional Entity webinar was conducted by NERC staff. Participants included Regional Entity staff in the Compliance and Enforcement Programs. This webinar provided an update on the 2011 filings with FERC of the associated FFTs. The webinar included questions and discussions among the presenters and participants. Approximately 30 Regional Entity representatives participated.

On December 13, 2011, a webinar was conducted for NERC members and industry stakeholders on the CEI. This webinar provided an update to the industry regarding the

September, October, and November 2011 filings with FERC of the associated FFTs and the NOPs. Additionally, guidance was provided for registered entities on best practices regarding the completion of the self-report template and risk assessments needed for FFTs processing. Discovery methods were presented, noting that a majority of FFTs resulted from self-reporting. Approximately 219 industry representatives registered for the webinar.

In early February 2012, a CEI information update webinar was conducted for NERC members and industry stakeholders. The focus of this webinar was to provide industry with the latest information relating to FFT issues processed to date. This included FFT background, statistics, analysis, and case studies to help registered entities better understand the FFT process and its use in promoting the reliability of the bulk power system. Topics included a summary of the first five CEI filings, and FFT trends by reliability standard family. A summary of FFT remediated issues was provided that included the potential violation, associated risk impact and mitigation actions completed for specific standards. The webinar included questions and discussions among the presenters and participants. Approximately 550 participants were registered for the webinar, including representatives from the Commission.

Also in February 2012, NERC conducted an ERO Auditor Workshop in Salt Lake City. This multi-day workshop was conducted for compliance staff from each Regional Entity and NERC. A session on the CEI was provided that included the goals of the CEI, FFT trends and examples. Approximately 110 staff attended the workshop.

In April 2012, NERC conducted a Standards and Compliance Workshop in San Diego for registered entities. The theme of the workshop was "A Risk-Based Approach to Reliability and Accountability" and included an information session on the compliance enforcement initiative.

Approximately 150 people attended the workshop with an additional 50 remote participants through webinar.

In addition, the CEI was discussed with registered entities and Regional Entities at each NERC board meeting as part of the Member Representatives Committee and the open Board of Trustees Compliance Committee meetings commencing in 2011.

II. NERC Staff Participation in Third Party Activities

NERC staff spoke at a brown bag luncheon of the Energy Bar Association on November 8, 2011, a webinar conducted by the Edison Electric Institute on January 19, 2012, and a panel presentation in the National Association of Regulatory Utility Commissioners' Winter Meetings on February 5, 2012, both in Washington DC. In addition, NERC staff spoke at a meeting of the Northwest Public Power Association in Seattle on March 1, 2012 and a webinar held by the North American Generator Forum on March 27, 2012. NERC staff also presented during the Energy Bar Association's Compliance & Enforcement Committee and Georgetown University Law Center's Energy Enforcers and Defenders Forum on April 2, 2012, the Annual Conference of the National Hydropower Association on April 17, 2012, the EEI Reliability Executive Advisory Committee on April 25, 2012, and the Energy Bar Association's Annual Meeting on April 26, 2012.

III. Regional Entity-sponsored Activities

Regional Entities have provided separate training on CEI and FFT. As reported to NERC, these training opportunities included as follows:

A. FRCC

Below is a list of FFT training that has been provided by FRCC to date.

FRCC
FFT Training

Date	Forum	Training Target
10/15/2011	Board of Directors	Registered Entities
12/15/2011	Board of Directors	Registered Entities
1/31/2012	Board of Directors	Registered Entities
8/22/2011	FRCC RE Compliance Committee	Registered Entities
9/21/2011	FRCC RE Compliance Committee	Registered Entities
10/26/2011	FRCC RE Compliance Committee	Registered Entities
3/27/2012	FRCC RE Compliance Committee	Registered Entities
4/25/2012	FRCC RE Compliance Committee	Registered Entities
10/10/2011	Fall 2011 Compliance Workshop	Registered Entities
10/11/2011	Fall 2011 Compliance Workshop	Registered Entities
10/12/2011	Fall 2011 Compliance Workshop	Registered Entities
10/13/2011	Fall 2011 Compliance Workshop	Registered Entities
10/14/2011	Fall 2011 Compliance Workshop	Registered Entities
3/12/2012	Spring 2012 Compliance Workshop	Registered Entities
3/13/2012	Spring 2012 Compliance Workshop	Registered Entities
3/14/2012	Spring 2012 Compliance Workshop	Registered Entities
3/15/2012	Spring 2012 Compliance Workshop	Registered Entities
3/16/2012	Spring 2012 Compliance Workshop	Registered Entities

B. MRO

MRO provided an overview of the CEI with an emphasis on the FFT Report Process at its Compliance Workshop on December 14, 2011. The workshop was conducted in conjunction with the 2011 Annual Member meeting and was attended by 150 registered entity staff. The presentation was posted on the MRO website within days of the Workshop. MRO provided an overview of the March 15, 2012 Commission Order at an open meeting of its Board of Directors on March 29, 2012. A report appears in the Board agenda posted on the MRO website.

Beginning with the Sept./Oct. 2011 edition, MRO has included an article about the CEI and FFT Report Process in each edition of its newsletter, Reliability Matters. These articles provide insight into how MRO has implemented the FFT Report Process and how registered entities can assist and/or participate in the process. The newsletter is sent to a broad distribution list including all registered entities within the MRO region, as well as those outside the MRO region that have requested to be added to the distribution list, Regional Entities, and other interested parties. The newsletter is also posted on the MRO website.

C. NPCC

As part of the Regional Entities sponsored activities, NPCC presented the FFT process to its registered entities at its 2011 Winter Compliance and Standards Workshop held on December 15, 2011.

D. RFC

Reliability*First* internal staff training has been ongoing since the implementation of the FFT, and includes review of NERC webinars and participation in discussions with NERC and

FERC (risk assessment improvements). Reliability*First* has monthly meetings with enforcement staff to discuss, *inter alia*, PV processing and risk-harm assessment to assist in training and the ongoing implementation of the FFT (and processing all violations, generally). Below is a list of the FFT training performed by Reliability*First* to date:

Date	Forum	Training Target
9/1/2011	Board of Directors	Registered entities
10/19/2011	Compliance Workshop (Baltimore)	Registered entities
2/20/2012	Compliance Webinar	Registered entities
2/22/2012	Compliance Committee	Registered entities
3/19/2012	Compliance Webinar	Registered entities
3/29/2012	Compliance Workshop (Pittsburgh)	Registered entities

E. SERC

Below is a list of FFT training that has been provided by SERC to date.

9/8/2011	Small Entity Workshop	Registered Entities
10/31/2011	Open Forum WebEx	Registered Entities
11/15/2011	Compliance Seminar: Atlanta	Registered Entities
11/29/2011	Compliance Seminar: Charlotte	Registered Entities
1/12/2012	SERC Auditor Training	SERC Staff
2/28/2012	Compliance Seminar: Charlotte (with presentation by NERC staff)	Registered Entities
4/11/2012	Compliance Seminar: New Orleans	Registered Entities
10/25/2011	SERC Board Compliance Committee	Registered Entities
10/26/2011	SERC Board of Directors	Registered Entities
10/6/2011	SERC Standing Committees	Registered Entities
3/13/2012	SERC Operating Committee	Registered Entities
10/18/2011	North American Generator Forum	Registered Entities
1/19/2012	SERC Board Compliance Committee	Registered Entities
3/6/2012	Enforcement Training and Legal Coordination	SERC Staff

F. SPP

SPP RE staff made presentations to registered entities in its Fall and Spring Workshops:

- Compliance Enforcement Initiative Update, February 29, 2012
- NERC's Compliance Enforcement Initiative October 5, 2011

G. Texas RE

Texas RE external CEI training since September 2011 includes:

- October 6, 2011 Standards and Compliance Workshop presentation ("New Compliance and Enforcement Initiatives") to discuss and answer stakeholder questions
- October 31, 2011 NERC Standards Review Subcommittee call on to discuss the CEI and answer questions from regional entities ("Find, Fix, Track, Report)
- April 18, 2012 bi-monthly Talk with Texas RE conference call and webinar ("FFT Update – After FERC Order") to discuss FFT and answer stakeholder questions

Texas RE internal training has been ongoing, and includes review of NERC webinars and participation in discussions with NERC and FERC (risk assessment improvements). Texas RE has monthly meetings with enforcement staff to discuss PV processing, and has flow charts of its internal procedures to assist in training. Enforcement staff has recently begun meeting with compliance staff to periodically discuss risk assessments of PVs.

H. WECC

On April 19, 2012, its monthly open webinar to the Compliance User Group (CUG), WECC provided an update regarding the FERC order on CEI/FFT. WECC also will conduct training on CEI and FFT as part of its CUG meeting on June 6, 2012 in Salt Lake City. WECC expects 400 registered entities (mostly compliance contacts) to be present.

Attachment B

CEA Staff Training Outline

In preparation for the continuing expansion of the CEI, FFT qualification training is expected to be available in the third and fourth quarters of 2012 to CEA staff to ensure successful implementation in the field, promote consistency and ensure processes, roles, and responsibilities are well understood. Training will focus on application of the factors to be considered in identifying FFT candidates and risk assessments illustrated by case studies of FFTs filed since September 2011 as guided by the March 15 Order. Training will be provided through instructor-led training in auditor workshops, quarterly audit team leader training courses, and dedicated live webinar sessions. Training materials will also be developed for online delivery covering the same topics and following the same principles described below. The fall 2012 ERO Auditor workshop will provide a venue for most auditors to participate in the training. Particular emphasis will be placed on risk assessment methods in determining FFT candidates. Training will be based on experience gained and processes developed and used since September 2011. The outline of training to be provided includes the following:

- CEI purpose and background
- Roles and responsibilities
- Terms and Definitions
- Guidance for quality self-reports
- Applicable NERC filings and FERC orders, and acceptance conditions for the FFT process
- FFT factors
    - Minimal risk to reliability[18] and related facts and circumstances, including what happened, why, where and when, including the timeframe for mitigation;
    - Reliability Standard at issue and applicable Violation Risk Factor (VRF) and Violation Severity Level (VSL);
    - Registered Entity's compliance program and compliance history.
- Documentation of possible violations processed as FFTs
    - Completing FFT report spreadsheet and final disposition
    - Certification that mitigation is complete
    - How an entity's compliance history was considered
    - Identification of the registered entity
- Case study exercises from actual FFT filings
- Communicating FFT process and decisions

Training and webinar information will be updated as additional experience is gained.

[18] Although certain moderate risk FFTs were filed between September 2011 and February 2012, as a result of the FERC order issued on March 15, 2012, only minimal risk issues will be included prospectively.

Training population – NERC and Regional Entity compliance monitoring staff, applicable enforcement staff.

- **Key points**
  - All issues are reported
  - NPV is issued for every item regardless of ultimate processing in FFT or NOP
  - Only possible violations that pose a minimal risk are eligible for FFT treatment
  - FFT evaluation includes several factors to consider
  - FFT spreadsheet is used to document the possible violation
  - Once FFT issues are included in a filing, they are final after 60 days, with exceptions
  - Formal mitigation plans not required, but entity must certify that all mitigation activities have been completed
  - Qualified compliance staff will be authorized to make FFT recommendations to enforcement staff

Learning Objectives:

- Describe the FFT process in detail for compliance audits and spot checks
- Describe the FFT process in detail for compliance investigations
- Discuss the conditions for the FFT acceptance contained in FERC Order issued March 15, 2012 including:
  - Minimal risk
  - Possible violations not mitigated are not eligible for filing until completed and certified
  - Certification that mitigation is complete
  - Review of entity compliance history
  - Identification of the entity
- Discuss possible violations that would typically not qualify for FFT treatment
- Describe the roles and responsibilities in the FFT processes for
  - Registered entity
  - Compliance monitoring staff
  - Regional Entity enforcement staff
  - NERC
- Use the FFT factors to determine if a possible violation is eligible for treatment in the FFT process
- Assess mitigation actions for adequacy and completeness
- Prepare a FFT spreadsheet report using “Guidance for Quality Self-Reports” to ensure appropriate and sufficient information is included

- Describe the handoff process for possible violations identified by an audit or investigation team
- Locate and use previous FFT filings as examples of acceptable reports

NERC and Regional Entity staff will lead the training sessions. Training will be conducted in accordance with generally accepted training principles. Training completion records will be maintained by NERC and Regional Entities.

Audit Team Leader training, conducted quarterly, will also include the FFT process.

Continuing training on the FFT process will be provided in the semi-annual ERO auditor workshops and periodic webinars as required based on experience and lessons learned from FFT processing.

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 14th day of May, 2012.

/s/ Rebecca J. Michael
Rebecca J. Michael
Associate General Counsel for Corporate
and Regulatory Matters

139 FERC ¶ 61,169
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

North American Electric Reliability Corporation Docket No. RD12-1-000

ORDER APPROVING REGIONAL RELIABILITY STANDARD

(Issued May 31, 2012)

1. On February 1, 2012, the North American Electric Reliability Corporation (NERC) submitted a petition requesting approval of Regional Reliability Standard IRO-006-TRE-1, associated Violation Severity Levels (VSL) and Violation Risk Factors (VRF), and an implementation plan for IRO-006-TRE-1. As discussed in this order, we approve the Regional Reliability Standard, VRFs and VSLs, and the implementation plan.

I. Background

A. EPAct 2005 and Mandatory Reliability Standards

2. Section 215 of the Federal Power Act (FPA) requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which provide for the reliable operation of the Bulk-Power System, subject to Commission review and approval.[1] Section 215(d)(2) of the FPA states that the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[2]

[1] 16 U.S.C. 824o(d)(2) (2006).

[2] *Id.* § 824o(e)(3).

3. On February 3, 2006, the Commission issued Order No. 672 to implement the requirements of section 215 of the FPA governing electric reliability.[3] In July 2006, the Commission certified NERC as the ERO.[4]

4. On March 16, 2007, the Commission issued Order No. 693,[5] approving 83 of the 107 Reliability Standards and associated definitions filed by NERC, including Reliability Standard IRO-006-3.[6] Reliability Standard IRO-006-3 established a detailed Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection to alleviate loadings on the system by curtailing or changing transactions based on their priorities and the severity of the transmission congestion. The Reliability Standard referenced other procedures for the Western Electricity Coordinating Council (WECC) and Electric Reliability Council of Texas (ERCOT). The Commission directed the ERO to modify the ERCOT procedures to ensure consistency with the standard form of the Reliability Standards including Requirements, Measures and Levels of Non-Compliance.[7]

5. On March 19, 2009, the Commission approved IRO-006-4, which modified the prior version of the Reliability Standard.[8] The Commission subsequently accepted an

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[3] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204 (2006), *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[4] *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[5] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[6] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 960-964.

[7] *Id.* P 964.

[8] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Order No. 713, 124 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 713-A, 126 FERC ¶ 61,252 (2009), *order on reh'g*, Order No. 713-B, 130 FERC ¶ 61,032 (2010).

erratum to that Reliability Standard that corrected the reference in Requirement R1.2 to the Unscheduled Flow Mitigation Plan.[9]

6. On April 21, 2011, the Commission approved Reliability Standard IRO-006-5, which removed references and associated links to the Interconnection-wide procedures (and regional differences) found in IRO-006-4.1 and its Attachment.[10] The key reliability elements of the Eastern Interconnection Transmission Loading Relief procedures in the Attachment to IRO-006-4.1 were moved into a separate, Interconnection-wide Reliability Standard, IRO-006-EAST-1, which was approved at the same time as IRO-006-5.[11] Separately, the Commission approved a Western Interconnection Transmission Loading Relief standard (IRO-006-WECC-1).[12]

B. NERC Petition

7. On February 1, 2012, NERC submitted a petition requesting approval of a separate Texas Interconnection Transmission Loading Relief standard, Regional Reliability Standard IRO-006-TRE-1, associated VSLs and VRFs, and an implementation plan for IRO-006-TRE-1. NERC states that Regional Reliability Standard IRO-006-TRE-1 will provide enforceable requirements to support Reliability Standard IRO-006-5.

8. NERC states that the Regional Reliability Standard was developed and approved by industry stakeholders using the Texas Reliability Entity's (Texas RE) *Texas Reliability Entity Standards Development Process*, then approved by the Texas RE Board of Directors on June 28, 2011, and subsequently approved by the NERC Board of Trustees on November 4, 2011.[13] NERC states that the Regional Reliability Standard is applicable to registered entities within the jurisdiction of Texas RE in the ERCOT Interconnection.

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[9] *North American Electric Reliability Corp.*, Docket No. RD09-9-000 (Dec. 10, 2009) (delegated letter order).

[10] *North American Electric Reliability Corp.*, 135 FERC ¶ 61,043 (2011).

[11] *Id.*

[12] *Western Electric Coordinating Council Qualified Transfer Path Unscheduled Flow Relief Regional Reliability Standard*, Order No. 746, 76 Fed. Reg. 16,691 (Mar. 25, 2011), FERC Stats. & Regs. ¶ 61,040 (2011).

[13] NERC Petition at 14.

9. NERC states that the Regional Reliability Standard was developed to provide and execute TLR procedures that can be used to avoid and mitigate Interconnection Reliability Operating Limit (IROL) and System Operating Limit (SOL) exceedances for the purpose of maintaining reliable operation of the bulk electric system in the ERCOT Interconnection.[14] NERC states that the issues addressed in IRO-006-TRE-1 are not otherwise covered by the continent-wide Reliability Standards. NERC also states that the Regional Reliability Standard addresses the Commission directive in Order No. 693 "to modify the … ERCOT procedures to ensure consistency with the standard form of the Reliability Standards including Requirements, Measures and Levels of Non-Compliance."[15]

10. The Regional Reliability Standard is applicable to reliability coordinators (RC) and requires the RC to have and implement procedures to provide Transmission Loading Relief for critical transmission facilities. Specifically, it will require ERCOT to have procedures to identify and mitigate SOL and IROL exceedances that will not be resolved by the automatic actions of the ERCOT Nodal market operations system.[16]

11. Requirement R1 states that the RC shall have procedures to identify and mitigate exceedances of identified IROLs and SOLs that will not be resolved by the automatic actions of the ERCOT Nodal market operations system. It also provides that the procedures shall address, but not be limited to, (1) redispatch of generation; (2) reconfiguration of the transmission system; and (3) controlled load reductions (including both firm and non-firm load shedding). Requirement R2 requires the RC to act in accordance with the procedures required by Requirement R1.

12. NERC requests that Reliability Standard IRO-006-TRE-1 be effective on the first day of the first calendar quarter following Commission approval.[17]

II. Notices of Filings and Responsive Pleadings

13. Notice of the NERC petition was published in the *Federal Register*, 77 Fed. Reg. 6553 (2012), with interventions and protests due on or before March 2, 2012. No motion to intervene or protest was received.

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[14] *Id*. at 1.

[15] *Id*. at 6 (*citing* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 964).

[16] *Id.* at 7-8.

[17] *See* NERC April 27, 2012 Errata.

III. Discussion

14. We approve Regional Reliability Standard IRO-006-TRE-1 and the associated VSLs and VRFs. We find that the proposed Regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission approves the procedures for requiring RCs to provide Transmission Loading Relief for critical transmission facilities, i.e., requiring ERCOT to have procedures to identify and mitigate SOL and IROL exceedances that will not be resolved by the automatic actions of the ERCOT Nodal market operations system. IRO-006-TRE-1 Regional Standard is part of a comprehensive set of standards designed to cover transmission loading relief. As NERC states in its filing, the Commission has previously approved corresponding standards, IRO-006-EAST-1 and IRO-006-WECC-1, which address similar reliability objectives in the Eastern and Western Interconnections. Moreover, Regional Reliability Standard IRO-006-TRE-1 addresses the Commission directive in Order No. 693 "to modify the … ERCOT procedures to ensure consistency with the standard form of the Reliability Standards including Requirements, Measures and Levels of Non-Compliance."[18]

15. The Commission also finds that NERC's proposed VRFs and VSLs for Reliability Standard IRO-006-TRE-1 are consistent with the Commission's established guidelines for review of proposed VRFs and VSLs. We therefore approve NERC's proposed VRFs and VSLs.

16. As requested by NERC, Reliability Standard IRO-006-TRE-1 will be effective on the first day of the first calendar quarter following the date of this order.

IV. Information Collection

17. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency actions.[19] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirement of this order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act[20] requires each federal agency to seek and obtain OMB approval before undertaking a collection of

[18] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 964.

[19] 5 C.F.R. § 1320.10 (2012).

[20] 44 U.S.C. § 3501-20.

information directed to ten or more persons, or continuing a collection for which OMB approval and validity of the control number are about to expire.[21]

18. The Commission approved the Reliability Standard on Transmission Loading Relief, on which the subject matter of this order is based, in Order No. 693. Reliability Standard IRO-006-3 referenced other procedures for WECC and ERCOT. The Regional Reliability Standard IRO-006-TRE-1 information collection requirements do not differ from those approved in Order No. 693 and successor Reliability Standards, and the Commission does not expect any changes to entities' current reporting burden. Accordingly, we will submit this order to OMB for informational purposes only.

The Commission orders:

The Commission hereby grants NERC's petition and approves Regional Reliability Standard IRO-006-TRE-1, the assigned VRFs and VSLs, and NERC's implementation plan, as discussed in this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[21] 44 U.S.C. § 3502(3)(A)(i), 44 U.S.C. § 3507(a)(3).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RD12-___**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION PETITION FOR APPROVAL OF ERRATA CHANGES TO SEVEN RELIABILITY STANDARDS

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June 5, 2012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)**	**Docket No. RD12-___**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION PETITION FOR APPROVAL OF ERRATA CHANGES TO SEVEN RELIABILITY STANDARDS

The North American Electric Reliability Corporation ("NERC") hereby requests approval pursuant to section 215(d)(1) of the Federal Power Act ("FPA") and section 39.5 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations[1] of errata changes to seven Reliability Standards currently on record with and approved by the Commission.

These errata changes do not substantively change the content or intent of the existing Commission-approved Reliability Standards and were therefore developed by NERC using an errata approval process in the Standard Processes Manual, set forth in Appendix 3A to the NERC Rules of Procedure.[2]

[1] 16 U.S.C. § 824o(2)(2012) and 18 C.F.R. § 39.5 (2011). Capitalized terms not otherwise defined herein, shall have the meaning set forth in the Glossary of Terms used in NERC Reliability Standards.

[2] Available here: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[3]

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II. BACKGROUND

Each of the proposed standards set forth in **Attachment A** was initially developed and approved by industry stakeholders using NERC's Reliability Standards Development Procedure and were subsequently approved by the Commission. Since that time, NERC has identified several ministerial corrections and/or clarifications that are needed.

The NERC Standards Committee developed and approved a process to administer the processing of errata changes to NERC standards that is outlined on page 40 of the Standard Processes Manual. Where the "correction of an error does not change the scope or intent of the associated standard, and [the Standards Committee] agrees that the correction has no material impact on the end users of the standard, then the correction shall be submitted for information to

[3] Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

the NERC Board of Trustees and filed for approval with applicable government authorities."[4] The Standards Committee has reviewed the instant proposed errata changes and has found that they do not change the scope or intent of the associated standards, nor do they have a material impact on the end users of the standards.[5] Upon Commission approval, these standards will supersede the existing Commission-approved versions of the standards.

III. PROPOSED ERRATA CHANGES

A. BAL-005-0.1b: Automatic Generation Control

On April 15, 2008, NERC submitted an interpretation of Requirement R17 of BAL-005 regarding the type and location of the equipment to which Requirement R17 applies. The Commission approved the interpretation on July 21, 2008, in Docket No. RM08-7-000.[6] On February 6, 2009, NERC submitted a revised version of BAL-005 that incorporated errata changes. The Commission approved these changes in an unpublished letter order on May 13, 2009, in Docket No. RD02-9-000.

In the instant filing, NERC has replaced Appendix 1 of the BAL-005 standard with the correct version of the interpretation and has made an internal reference correction in the interpretation; changing "BAL-005-1" to "BAL-005-0." As a result of these changes, this standard will be numbered "BAL-005-0.2b" on a going-forward basis. NERC has also updated the version history table to reflect these revisions and to incorporate additional information regarding the adoption of Version 0 of this standard.

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[4] *See* p. 40 of the Standard Process Manual, available here: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf.

[5] The errata included herein were approved by the Standards Committee on March 8, 2012 and April 11, 2012. *See* http://www.nerc.com/docs/standards/sc/sc_20120411a_package_final.pdf.

[6] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Order No. 713, 124 FERC ¶ 61,071 (2008).

B. EOP-001-0b and EOP-002b: Emergency Operations Planning

In Order No. 693, the Commission approved 83 of the 107 Reliability Standards filed by NERC, including the Emergency Operations and Preparedness ("EOP") Reliability Standard, EOP-001-0.[7] On March 17, 2011, the Commission approved EOP-001-1 in Docket No. RM10-16-000.[8] On the same day, the Commission also approved version 2 of EOP-001 in Order No. 748 in Docket No. RM10-15-000.[9] As the Commission later clarified, each NERC Petition in Docket Nos. RM10-15-000 and RM10-16-000 proposed unique changes to EOP-001-0 not reflected in the other petition, presenting a logistical problem with cross-references. [10]

On September 9, 2011, NERC submitted for Commission approval an interpretation of Requirements R1 and R3.2 of Reliability Standard EOP-001-0 and Requirements R1 and R2.2 to EOP-001-2. The Commission approved the interpretation on December 15, 2011.[11] EOP-001-0 is the currently effective Reliability Standard and EOP-001-2 becomes effective on July 1, 2013.[12] For this reason, NERC is proposing errata to both versions of this standard as described below.

1. EOP-001-0b: Emergency Operations Planning

NERC has updated the title of Attachment 1 and corrected internal references throughout the standard by changing "Attachment EOP-001-0b" to "Attachment EOP-001." In addition, an incorrect internal reference in Appendix 2 of Reliability Standard EOP-001-0b has been changed

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[7] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[8] *System Restoration Reliability Standards*, Order No. 749, 134 FERC ¶ 61,215 (2011) *order on clarification*, 136 FERC ¶ 61,030 (2011).

[9] *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, Order No. 748, 134 FERC ¶ 61,213 (2011), *order on clarification*, 136 FERC ¶ 61,030 (2011).

[10] 136 FERC ¶ 61,030 at P 9 (2011).

[11] *North American Electric Reliability Corporation*, 137 FERC ¶ 61,196 (2011).

[12] *Id.* at P 18 ("Accordingly, the Commission approves Reliability Standard EOP-001-0b, effective as of the date of this order. In addition, the Commission approves the retirement of Reliability Standard EOP-001-0b effective as of June 30, 2013,and an effective date of July 1, 2013 for Reliability Standard EOP-001-2b, consistent with the Commission's approval of Reliability Standard EOP-001-2 in Order Nos. 748 and 749.")(internal citations omitted).

from “R2.2” to “R3.2.” As a result of these changes, the number of this standard will be “EOP-001-0.1b” on a going-forward basis. NERC has also updated the version history table to reflect these revisions.

2. EOP-001-2b: Emergency Operations Planning

NERC has updated the title of Attachment 1 and corrected internal references throughout the standard by changing “Attachment EOP-001-0b” to “Attachment EOP-001.” NERC has also updated references in Appendix 1 from “EOP-001-0” to “EOP-001-2.” As a result of these changes, the number of this standard will be “EOP-001-2.1b” on a going-forward basis. NERC has also updated the version history table to reflect these revisions.

C. EOP-002-3: Capacity and Energy Emergencies

NERC has updated the title of Attachment 1 and corrected internal references to Attachment 1 throughout the standard form “Attachment 1-EOP-002-0 Energy Emergency Alert Levels” to “Attachment 1-EOP-002 Energy Emergency Alerts.” NERC has removed the parenthetical in Requirement R9 that references a retired Attachment in IRO-006. As a result of these changes, this standard will be numbered “EOP-002-3.1” on a going-forward basis. NERC has also updated the version history table to reflect these revisions.

D. IRO-005-3a: Reliability Coordination – Current Day Operations

NERC has removed outdated internal references in Measures M10 and M11 to “Part 2” of Requirements R10 and R11, as no such Parts currently exist. As a result of these changes, this standard will be numbered “IRO-005-3.1a” on a going-forward basis. NERC has also updated the version history table to reflect these revisions and to add clarifying language regarding Versions 2a and 3a of this standard.

E. PER-001-0.1: Operating Personnel Responsibility and Authority

NERC has made a minor clarifying correction to the language in Measure M1.4 by changing the placement of the word "Interconnection." Measure M1.4 currently states: "Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations." NERC's proposed errata clarifies that the correct term intended to apply in this Measure is "Interconnection Reliability Operating Limit," which is a defined term in the NERC Glossary of Terms Used in Reliability Standards.[13] As a result of this change, this standard will be numbered "PER-001-0.2" on a going-forward basis. NERC has also updated the version history table to reflect this revision.

F. TOP-002-2b: Normal Operations Planning

On April 15, 2011, NERC submitted a Petition for Approval of an Interpretation to Requirement R10 of Reliability Standard TOP-002-2a— Normal Operations Planning in Docket No. RD11-9-000 that was accepted by the Commission on October 20, 2011.[14] It has come to NERC's attention that on page 1 of Reliability Standard TOP-002-2b included in Exhibit B of the original filing, the following language in the Effective Date section should be omitted, "FERC Approved 12/2/09." In addition, Requirement R14 contains two sub-requirements (R.14.1 and R.14.2), that are no longer effective as they were retired, as stated therein, on August 1, 2007. NERC has removed these sub-requirements, and also removed the following outdated parenthetical from R.14.1, "(Effective August 1, 2007)."

NERC has also updated Measure M7 to reflect these changes to Requirement R14. The modified Measure M7 states: "Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice

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[13] Available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[14] *North American Electric Reliability Corp.*, 137 FERC ¶ 61,061 (2011).

recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real output capabilities. (Requirement 14)"

As a result of these changes, this standard will be numbered "TOP-002-2.1b" on a going-forward basis. NERC has also updated the version history table to reflect these revisions.

IV. ATTACHMENTS

NERC's petition consists of the following documents in addition to the instant transmittal letter:

Attachment A **Clean Versions of the Proposed Errata to Reliability Standards, including**:

- BAL-005-0.2b: Automatic Generation Control
- EOP-001-0.1b: Emergency Operations Planning
- EOP-001-2.1b: Emergency Operations Planning
- EOP-002-3.1: Capacity and Energy Emergencies
- IRO-005-3.1a: Reliability Coordination – Current Day Operations
- PER-001-0.2: Operating Personnel Responsibility and Authority
- TOP-002-2b: Normal Operations Planning

Attachment B **Redlined Versions of Proposed Errata to Reliability Standards**

V. CONCLUSION

The North American Electric Reliability Corporation respectfully requests that the Commission approve errata revisions to seven Reliability Standards contained in this filing, effective immediately upon Commission approval, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of the Commission's regulations.

Respectfully submitted,

/s/ Stacey Tyrewala

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Attachment A

Clean Versions of the Proposed Errata to Reliability Standards

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-0.2b

3. **Purpose:** This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Effective Date:** May 13, 2009

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical

locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or

Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to "0.1b"	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from "BAL-005-1" to "BAL-005-0)	Errata

Appendix 1

Effective Date: August 27, 2008 (U.S.)

Interpretation of BAL-005-0 Automatic Generation Control, R17

Request for Clarification received from PGE on July 31, 2007

PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:

- *Only equipment within the operations control room*
- *Only equipment that provides values used to calculate AGC ACE*
- *Only equipment that provides values to its SCADA system*
- *Only equipment owned or operated by the BA*
- *Only to new or replacement equipment*
- *To all equipment that a BA owns or operates*

BAL-005-0

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

Existing Interpretation Approved by Board of Trustees May 2, 2007

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.

Interpretation provided by NERC Frequency Task Force on September 7, 2007 and Revised on November 16, 2007

As noted in the existing interpretation, BAL-005-0 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17.

The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

A. Introduction

1. Title: **Emergency Operations Planning**

2. Number: EOP-001-0.1b

3. Purpose: Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. Applicability

4.1. Balancing Authorities.

4.2. Transmission Operators.

5. Effective Date: April 1, 2005

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R4.4. Staffing levels for the emergency.

R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.

R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: One of the applicable elements of Attachment 1-EOP-001 has not been addressed in the emergency plans.

2.2. Level 2: Two of the applicable elements of Attachment 1-EOP-001 have not been addressed in the emergency plans.

2.3. Level 3: Three of the applicable elements of Attachment 1-EOP-001 have not been addressed in the emergency plans.

2.4. Level 4: Four or more of the applicable elements of Attachment 1-EOP-001 have not been addressed in the emergency plans or a plan does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2 (R3.2 in EOP-001-0)
0b	December 15, 2011	FERC Order issued approving Interpretation of R1 and R3.2 (Order effective December 15, 2011)	Project 2008-09 - Interpretation of Requirement R1 and Project 2009-28 - Interpretation of Requirement R2.2 (R3.2 in EOP-001-0)
0.1b	March 8, 2012	Errata adopted by Standards Committee; (changed title and references to Attachment 1 to omit inclusion of version numbers and corrected reference in Appendix 2 from “R2.2” to “R3.2”)	Errata

Attachment 1-EOP-001

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

Appendix 2

Requirement Number and Text of Requirement
R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001."

A. Introduction

1. Title: **Emergency Operations Planning**

2. Number: EOP-001-2.1b

3. Purpose: Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. Applicability

4.1. Balancing Authorities.

4.2. Transmission Operators.

5. Proposed Effective Date: Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. Each Transmission Operator and Balancing Authority shall:

R2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R2.3. Develop, maintain, and implement a set of plans for load shedding.

R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R3.1. Communications protocols to be used during emergencies.

R3.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R3.4. Staffing levels for the emergency.

R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.

R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R6.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R6.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R6.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.
R2	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	N/A	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.
R2.1	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of emergency plans to mitigate insufficient generating capacity emergency plans but the plans are not maintained.	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating capacity.
R2.2	The Transmission Operator or Balancing Authority's plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.	The Transmission Operator or Balancing Authority's transmission system emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.

Requirement	Lower	Moderate	High	Severe
R2.3	The Transmission Operator or Balancing Authority's load shedding plans are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.	The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.
R3	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-components.
R3.1	The Transmission Operator or Balancing Authority's communication protocols included in the emergency plan are missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.
R3.2	The Transmission Operator or Balancing Authority's list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.	N/A	The Transmission Operator or Balancing Authority provided a list of controlling actions, however the actions fail to resolve the emergency within NERC-established timelines.	The Transmission Operator or Balancing Authority has failed to provide a list of controlling actions to resolve the emergency.

Requirement	Lower	Moderate	High	Severe
R3.3	The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.
R3.4	The Transmission Operator or Balancing Authority's emergency plan does not include staffing levels for the emergency	N/A	N/A	N/A
R4	The Transmission Operator and Balancing Authority's emergency plan has complied with 90% or more of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 70% to 90% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with between 50% to 70% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 50% or less of the number of sub-components
R5	The Transmission Operator and Balancing Authority is missing minor program/procedural elements.	The Transmission Operator and Balancing Authority has failed to annually review one of it's emergency plans	The Transmission Operator and Balancing Authority has failed to annually review two of its emergency plans or communicate with one of it's neighboring Balancing Authorities.	The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.
R6	The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more of the sub-components.

Requirement	Lower	Moderate	High	Severe
R6.1	The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected systems.	N/A	N/A	N/A
R6.2	The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.	N/A	N/A	N/A
R6.3	The Transmission Operator or Balancing Authority has failed to coordinate transmission and generator maintenance schedules to maximize capacity or conserve fuel in short supply.	N/A	N/A	N/A
R6.4	The Transmission Operator or Balancing Authority has failed to arrange for deliveries of electrical energy or fuel from remote systems through normal operating channels.	N/A	N/A	N/A

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	October 17, 2008	Deleted R2 Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels Corrected typographical errors in BOT approved version of VSLs	Revised IROL Project
2	August 5, 2009	Removed R2.4 as redundant with EOP-005-2 Requirement R1 for the Transmission Operator; the Balancing Authority does not need a restoration plan.	Revised Project 2006-03
2	August 5, 2009	Adopted by NERC Board of Trustees: August 5, 2009	Revised
2	March 17, 2011	FERC Order issued approving EOP-001-2 (Clarification issued on July 13, 2011)	Revised
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2
2b	December 15, 2011	FERC Order issued approving Interpretation of R1 and R2.2 (Order effective December 15, 2011)	Project 2008-09 - Interpretation of Requirement R1 and Project 2009-28 - Interpretation of Requirement R2.2
2.1b	March 8, 2012	Errata adopted by Standards Committee; (changed title and references to Attachment 1 to omit inclusion of version numbers and corrected references in Appendix 1 Question 4 from "EOP-001-0" to "EOP-001-2")	Errata

Attachment 1-EOP-001

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-2, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-2.

Appendix 2

Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001."

Standard EOP-002-3.1 — Capacity and Energy Emergencies

A. Introduction

1. **Title**: **Capacity and Energy Emergencies**

2. **Number**: EOP-002-3.1

3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Reliability Coordinators.

   4.3. Load-Serving Entities.

5. **(Proposed) Effective Date:** First day of the first calendar quarter six months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Interrupting interruptible load and exports.

R6.4. Requesting emergency assistance from other Balancing Authorities.

R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff:

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements one or more actions described in its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.

M4. The Balancing Authority shall have and provide upon request evidence (such as operator logs, work orders, E-Tags, or other evidence) that it took the actions described in R4 in response to anticipating a capacity or energy emergency.

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)

M6. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took actions such as those listed in R6 to comply with CPS and DCS.

M7. The Balancing Authority shall have and provide upon request evidence (such as operator logs, voice recordings, or other evidence) that it took the actions listed in R7 when unable to resolve an emergency condition.

M8. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 “Energy Emergency Alerts.”

M9. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not Applicable.

1.3. Compliance Monitoring and Enforcement Process

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 8 and 9 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3, 4, 5, 6, and 7 the Balancing Authority shall keep 90 days of historical data.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to “Requirement 6” instead of “Requirement 7”	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. “Applicability.”	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted “4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to “2.1”	Errata
2.1	May 13, 2009	FERC Approved	Revised
3	June 4, 2010	Modified to address Order No. 693 Directives contained in paragraphs 582.	Revised.
3	August 5, 2010	Adopted by NERC Board of Trustees	New
3.1	March 8, 2012	Errata adopted by Standards Committee; (Updated title of Attachment 1 and changed	Errata

		references to Attachment 1 throughout Standard from "Attachment 1-EOP-002-0 Energy Emergency Alert Levels" to "Attachment 1-EOP-002 Energy Emergency Alerts". Removed parenthetical in Requirement R9 referencing a retired Attachment in IRO-006)	

Attachment 1-EOP-002
Energy Emergency Alerts

Introduction
This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

    1.1. **Situations for initiating alert.** An Energy Emergency Alert may be initiated for the following reasons:

    - When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
    - The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction
To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. Alert 1 — All available resources in use.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. Alert 2 — Load management procedures in effect.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform

[1] For emergency, not economic, reasons.

the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the

affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. **Operating Reserves being utilized.**

Comments:

Reported By:	**Organization:**
Title:	

A. Introduction

1. Title: Reliability Coordination — Current Day Operations

2. Number: IRO-005-3.1a

3. Purpose: The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

4. Applicability

4.1. Reliability Coordinators.

4.2. Balancing Authorities.

4.3. Transmission Operators.

4.4. Transmission Service Providers.

4.5. Generator Operators.

4.6. Load-Serving Entities.

4.7. Purchasing-Selling Entities.

5. Effective Date:

In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.

R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.4. System real and reactive reserves (actual versus required).

R1.5. Capacity and energy adequacy conditions.

R1.6. Current ACE for all its Balancing Authorities.

R1.7. Current local or Transmission Loading Relief procedures in effect.

R1.8. Planned generation dispatches.

R1.9. Planned transmission or generation outages.

R1.10. Contingency events.

R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R7. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R10. In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R11. The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)

M3. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)

M4. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.

M6. The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)

M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance

outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)

M8. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)

M9. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 9)

M10. If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Requirement 10)

M11. The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11)

M12. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.

M13. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.

M14. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-1 R1.1 through R1.10.	The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-1 R1.1 through R1.10.	The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-1 R1.1 through R1.10.	The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-1 R1.1 through R1.10.
R1.1	The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	N/A	N/A	N/A
R1.2	The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	N/A	N/A	N/A

Requirement	Lower	Moderate	High	Severe
R1.3	The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	N/A	N/A	N/A
R1.4	The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).	N/A	N/A	N/A
R1.5	The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.	N/A	N/A	N/A
R1.6	The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.	N/A	N/A	N/A
R1.7	The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.	N/A	N/A	N/A
R1.8	The Reliability Coordinator failed to monitor planned generation dispatches.	N/A	N/A	N/A
R1.9	The Reliability Coordinator failed to monitor planned transmission or generation outages.	N/A	N/A	N/A

Requirement	Lower	Moderate	High	Severe
R1.10	The Reliability Coordinator failed to monitor contingency events.	N/A	N/A	N/A
R2	N/A	The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities.	The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements.
R3	N/A	N/A	The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans.	The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.
R4	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.

Requirement	Lower	Moderate	High	Severe
R5	N/A	N/A	The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance.	The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

Requirement	Lower	Moderate	High	Severe
R6	N/A	The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans, or the Reliability Coordinator coordinated pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in the real-time reliability analysis timeframe but failed to coordinate pending generation and transmission maintenance outages in the next-day reliability analysis timeframe.	The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations, or the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.	The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.
R7	N/A	N/A	N/A	The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.

Requirement	Lower	Moderate	High	Severe
R8	N/A	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS.	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority.	The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.
R9	N/A	N/A	N/A	The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Special Protection System that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

Requirement	Lower	Moderate	High	Severe
R10	N/A	N/A	N/A	The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.
R11	N/A	N/A	N/A	The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
R12	N/A	The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.	N/A	The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17 Retired M2 and M3; modified M9 and M12; retired M13 Made conforming changes to data retention Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Retired VSLs associated with R2, R3, R5, R16 and R17; Modified VSLs associated with R9 and R13, and R14	Revised
2	November 1, 2006	Approved by the Board of Trustees	
2	January 1, 2007	Effective Date	
2a	November 5, 2009	Approved by the Board of Trustees	
3	October 17, 2008	Approved by the Board of Trustees	
3	March 23, 2011	Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)	
3a	April 21, 2011	Added FERC approved Interpretation	
3.1a	March 8, 2012	Errata adopted by Standards Committee; (removed outdated references in Measures M10 and M11 to 'Part 2' of Requirements R10 and R11)	Errata

Appendix 1

Requirement Number and Text of Requirement
TOP-005-1 Requirement R3 Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability. *The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6:* New or degraded special protection systems. *[Underline added for emphasis.]* **IRO-005-1 Requirement R12**[1] **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected. *[Underline added for emphasis.]* **PRC-012-0 Requirements R1 and R1.3** **R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: **R1.3.** Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
Background Information for Interpretation
The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a "performance mandate." Requirement R3 defines the obligation to provide data "requested" by other reliability entities that is needed "to perform assessments and to coordinate operations." The Attachment to TOP-005-1 is provided as a guideline of what "can be shared." The Attachment is not an obligation of "what must be shared." Enforceable NERC Requirements must be explicitly contained within a given Standard's approved requirements. In this case, the standard only requires data "upon request." If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that

[1] In the current version of the Standard (IRO-005-3a), this requirement is R9.

data (including item 2.6, whether it is or is not in some undefined "degraded" state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator's obligation to be aware of conditions that may have a "significant" impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term "degraded."

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

A. Introduction

1. Title: **Operating Personnel Responsibility and Authority**

2. Number: PER-001-0.2

3. Purpose: Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. Applicability

4.1. Transmission Operators.

4.2. Balancing Authorities.

5. Effective Date: December 10, 2009

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The job description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit or Interconnection Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0.1	April 15, 2009	Replaced “position” with “job” on M1.1	Errata
0.1	April 15, 2009	Errata adopted by Standards Committee	Errata
0.1	December 10, 2009	Approved by FERC — added effective date	Update

0.2	March 8, 2012	Errata adopted by Standards Committee; (moved the word, “Interconnection” in Measure M1.4. so that it appears as the first word in the term “Interconnection Reliability Operating Limit” rather than the last word in the phrase, “System Operating Limit Interconnection)	Errata

Standard TOP-002-2.1b — Normal Operations Planning

A. Introduction

1. **Title:** **Normal Operations Planning**

2. **Number:** TOP-002-2.1b

3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

   4.3. Generator Operator.

   4.4. Load Serving Entity.

   4.5. Transmission Service Provider.

5. **Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real output capabilities.

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of

current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real output capabilities. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

3.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

3.2. Level 2: Not applicable.

3.3. Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

3.4.3 Studies not updated to reflect current system conditions as specified in R11.

3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. Levels of Non-Compliance for Generator Operators:

4.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

5.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata

Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a "unique" study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have "a" study that can be applied to it, but it is not necessary to generate a "unique" study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a "study"? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, "to determine SOLs" as used in the first sentence of Requirement R11 mean the "determination of system operating limits" or does it mean the "identification of potential SOL violations?"

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential "exceedances" of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.

Appendix 2

Requirement Number and Text of Requirement:

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

Clarification needed:

Requirement 10 is proposed to be eliminated in Project 2007-03 because it is redundant with TOP-004-0 R1, which only applies to TOP not to BA. However, that will not be effective for more than two years. In the meantime, in Requirement 10 is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

Project 2009-27: Response to Request for an Interpretation of TOP-002-2a, Requirement R10, for Florida Municipal Power Pool

The following interpretation of TOP-002-2a — Normal Operations Planning, Requirement R10, was developed by the Real-time Operations Standard Drafting Team.

Requirement Number and Text of Requirement

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

Question

In Requirement 10, is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

Response

Yes. As stated in the NERC *Glossary of Terms used in Reliability Standards*, the Balancing Authority is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area, and supporting Interconnection frequency in real time. The Balancing Authority does not possess the Bulk Electric System information necessary to manage transmission flows (MW, MVAR or Ampere) or voltage. Therefore, the Balancing Authority must follow the directions of the Transmission Operator to meet all SOLs and IROLs.

Attachment B

Redlined Versions of Proposed Errata to Reliability Standards

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-0.~~1b~~2b

3. **Purpose:** This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Effective Date:** May 13, 2009

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical

locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or

Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to "0.1b"	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from "BAL-005-1" to "BAL-005-0)	Errata

Appendix 1

Effective Date: August 27, 2008 (U.S.)

Interpretation of BAL-005-0 Automatic Generation Control, R17

Request for Clarification received from PGE on July 31, 2007

PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:

- *Only equipment within the operations control room*
- *Only equipment that provides values used to calculate AGC ACE*
- *Only equipment that provides values to its SCADA system*
- *Only equipment owned or operated by the BA*
- *Only to new or replacement equipment*
- *To all equipment that a BA owns or operates*

BAL-005-0

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

Existing Interpretation Approved by Board of Trustees May 2, 2007

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.

Interpretation provided by NERC Frequency Task Force on September 7, 2007 and Revised on November 16, 2007

As noted in the existing interpretation, BAL-005-0 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17.

The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

~~**Appendix 1***PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:*~~

- ~~*Only equipment within the operations control room*~~
- ~~*Only equipment that provides values used to calculate AGC ACE*~~
- ~~*Only equipment that provides values to its SCADA system*~~
- ~~*Only equipment owned or operated by the BA*~~
- ~~*Only to new or replacement equipment*~~
- ~~*To all equipment that a BA owns or operates*~~

~~**BAL-005-1**~~

~~**R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:~~

~~**Device**~~	~~**Accuracy**~~
~~Digital frequency transducer~~	~~≤ 0.001 Hz~~
~~MW, MVAR, and voltage transducer~~	~~≤ 0.25% of full scale~~
~~Remote terminal unit~~	~~≤ 0.25% of full scale~~
~~Potential transformer~~	~~≤ 0.30% of full scale~~
~~Current transformer~~	~~≤ 0.50% of full scale~~

~~**Existing Interpretation Approved by Board of Trustees May 2, 2007**~~

~~BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.~~

~~The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.~~

~~**Interpretation:**~~

~~As noted in the existing interpretation, BAL-005-1 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.~~

~~New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.~~

A. Introduction

1. Title: **Emergency Operations Planning**

2. Number: EOP-001-~~0b~~0.1b

3. Purpose: Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. Applicability

4.1. Balancing Authorities.

4.2. Transmission Operators.

5. Effective Date: April 1, 2005

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R4.4. Staffing levels for the emergency.

R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-~~0b~~ when developing an emergency plan.

R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-~~0b~~.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: One of the applicable elements of Attachment 1-EOP-001-~~0b~~ has not been addressed in the emergency plans.

2.2. Level 2: Two of the applicable elements of Attachment 1-EOP-001-~~0b~~ have not been addressed in the emergency plans.

2.3. Level 3: Three of the applicable elements of Attachment 1-EOP-001-~~0b~~ have not been addressed in the emergency plans.

2.4. Level 4: Four or more of the applicable elements of Attachment 1-EOP-001-~~0b~~ have not been addressed in the emergency plans or a plan does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2 (R3.2 in EOP-001-0)
0b	December 15, 2011	FERC Order issued approving Interpretation of R1 and R3.2 (Order effective December 15, 2011)	Project 2008-09 - Interpretation of Requirement R1 and Project 2009-28 - Interpretation of Requirement R2.2 (R3.2 in EOP-001-0)
0.1b	March 8, 2012	Errata adopted by Standards Committee; (changed title and references to Attachment 1 to omit inclusion of version numbers and corrected reference in Appendix 2 from “R2.2” to “R3.2”)	Errata

Attachment 1-EOP-001-~~0b~~

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

Appendix 2

Requirement Number and Text of Requirement
~~R2~~R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001~~-0~~."

A. Introduction

1. Title: **Emergency Operations Planning**

2. Number: EOP-001-~~2b~~2.1b

3. Purpose: Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. Applicability

4.1. Balancing Authorities.

4.2. Transmission Operators.

5. Proposed Effective Date: Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. Each Transmission Operator and Balancing Authority shall:

R2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R2.3. Develop, maintain, and implement a set of plans for load shedding.

R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R3.1. Communications protocols to be used during emergencies.

R3.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R3.4. Staffing levels for the emergency.

R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-~~0b~~ when developing an emergency plan.

R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R6.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R6.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R6.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-~~0b~~.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.
R2	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	N/A	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.
R2.1	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of emergency plans to mitigate insufficient generating capacity emergency plans but the plans are not maintained.	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating capacity.
R2.2	The Transmission Operator or Balancing Authority's plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.	The Transmission Operator or Balancing Authority's transmission system emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.

Requirement	Lower	Moderate	High	Severe
R2.3	The Transmission Operator or Balancing Authority's load shedding plans are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.	The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.
R3	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-components.
R3.1	The Transmission Operator or Balancing Authority's communication protocols included in the emergency plan are missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.
R3.2	The Transmission Operator or Balancing Authority's list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.	N/A	The Transmission Operator or Balancing Authority provided a list of controlling actions, however the actions fail to resolve the emergency within NERC-established timelines.	The Transmission Operator or Balancing Authority has failed to provide a list of controlling actions to resolve the emergency.

Requirement	Lower	Moderate	High	Severe
R3.3	The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.
R3.4	The Transmission Operator or Balancing Authority's emergency plan does not include staffing levels for the emergency	N/A	N/A	N/A
R4	The Transmission Operator and Balancing Authority's emergency plan has complied with 90% or more of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 70% to 90% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with between 50% to 70% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 50% or less of the number of sub-components
R5	The Transmission Operator and Balancing Authority is missing minor program/procedural elements.	The Transmission Operator and Balancing Authority has failed to annually review one of it's emergency plans	The Transmission Operator and Balancing Authority has failed to annually review two of its emergency plans or communicate with one of it's neighboring Balancing Authorities.	The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.
R6	The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-	The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-	The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the	The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more

Requirement	Lower	Moderate	High	Severe
	components.	components.	sub-components.	of the sub-components.
R6.1	The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected systems.	N/A	N/A	N/A
R6.2	The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.	N/A	N/A	N/A
R6.3	The Transmission Operator or Balancing Authority has failed to coordinate transmission and generator maintenance schedules to maximize capacity or conserve fuel in short supply.	N/A	N/A	N/A

Requirement	Lower	Moderate	High	Severe
R6.4	The Transmission Operator or Balancing Authority has failed to arrange for deliveries of electrical energy or fuel from remote systems through normal operating channels.	N/A	N/A	N/A

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	October 17, 2008	Deleted R2 Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels Corrected typographical errors in BOT approved version of VSLs	Revised IROL Project
2	August 5, 2009	Removed R2.4 as redundant with EOP-005-2 Requirement R1 for the Transmission Operator; the Balancing Authority does not need a restoration plan.	Revised Project 2006-03
2	August 5, 2009	Adopted by NERC Board of Trustees: August 5, 2009	Revised
2	March 17, 2011	FERC Order issued approving EOP-001-2 (Clarification issued on July 13, 2011)	Revised
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2
2b	December 15, 2011	FERC Order issued approving Interpretation of R1 and R2.2 (Order effective December 15, 2011)	Project 2008-09 - Interpretation of Requirement R1 and Project 2009-28 - Interpretation of Requirement R2.2

~~**Attachment 1 EOP-001-0b**~~

2.1b	March 8, 2012	Errata adopted by Standards Committee; (changed title and references to Attachment 1 to omit inclusion of version numbers and corrected references in Appendix 1 Question 4 from “EOP-001-0” to “EOP-001-2”)	Errata

Attachment 1-EOP-001

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-~~0~~2, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-~~0~~2.

Appendix 2

Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001~~-0~~."

Standard EOP-002-3.1 — Capacity and Energy Emergencies

A. Introduction

1. **Title**: **Capacity and Energy Emergencies**

2. **Number**: EOP-002-3.1

3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Reliability Coordinators.

   4.3. Load-Serving Entities.

5. **(Proposed) Effective Date:** First day of the first calendar quarter six months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan~~,~~ to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Interrupting interruptible load and exports.

R6.4. Requesting emergency assistance from other Balancing Authorities.

R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency ~~Alert Levels~~Alerts."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency ~~Alert Levels~~Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff ~~(See Attachment 1-IRO-006-0 "Transmission Loading Relief Procedure" for explanation of Transmission Service Priorities):~~:

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0. "Energy Emergency Alerts."

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements one or more actions described in its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice

recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.

M4. The Balancing Authority shall have and provide upon request evidence (such as operator logs, work orders, E-Tags, or other evidence) that it took the actions described in R4 in response to anticipating a capacity or energy emergency.

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)

M6. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took actions such as those listed in R6 to comply with CPS and DCS.

M7. The Balancing Authority shall have and provide upon request evidence (such as operator logs, voice recordings, or other evidence) that it took the actions listed in R7 when unable to resolve an emergency condition.

M8. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 "Energy Emergency ~~Alert Levels.~~Alerts."

M9. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not Applicable.

1.3. Compliance Monitoring and Enforcement Process

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 8 and 9 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3, 4, 5, 6, and 7 the Balancing Authority shall keep 90 days of historical data.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to “Requirement 6” instead of “Requirement 7”	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. “Applicability.”	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted “4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to “2.1”	Errata
2.1	May 13, 2009	FERC Approved	Revised
3	June 4, 2010	Modified to address Order No. 693 Directives contained in paragraphs 582.	Revised.

~~Attachment 1-EOP-002-2.1~~3	August 5, 2010	Adopted by NERC Board of Trustees	New
3.1	March 8, 2012	Errata adopted by Standards Committee; (Updated title of Attachment 1 and changed references to Attachment 1 throughout Standard from "Attachment 1-EOP-002-0 Energy Emergency Alert Levels" to "Attachment 1-EOP-002 Energy Emergency Alerts". Removed parenthetical in Requirement R9 referencing a retired Attachment in IRO-006)	Errata

Attachment 1-EOP-002
Energy Emergency Alerts

Introduction
This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

1.1. **Situations for initiating alert.** An Energy Emergency Alert may be initiated for the following reasons:

- When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
- The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction
To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An

Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **Alert 1 — All available resources in use.**

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect**.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should

[1] For emergency, not economic, reasons.

include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of

downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. **Alert 0 - Termination.** When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. **Notification.** The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. Operating Reserves being utilized.

Comments:

Reported By: **Organization:**

Title:

A. Introduction

1. Title: **Reliability Coordination — Current Day Operations**

2. Number: IRO-005-~~3a~~3.1a

3. Purpose: The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

4. Applicability

4.1. Reliability Coordinators.

4.2. Balancing Authorities.

4.3. Transmission Operators.

4.4. Transmission Service Providers.

4.5. Generator Operators.

4.6. Load-Serving Entities.

4.7. Purchasing-Selling Entities.

5. Effective Date:

In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.

R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.4. System real and reactive reserves (actual versus required).

R1.5. Capacity and energy adequacy conditions.

R1.6. Current ACE for all its Balancing Authorities.

R1.7. Current local or Transmission Loading Relief procedures in effect.

R1.8. Planned generation dispatches.

R1.9. Planned transmission or generation outages.

R1.10. Contingency events.

R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R7. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R10. In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R11. The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)

M3. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)

M4. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.

M6. The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)

M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance

outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)

M8. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)

M9. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 9)

M10. If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (~~Part 2 of~~ Requirement 10)

M11. The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11 ~~Part 2~~)

M12. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.

M13. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.

M14. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-1 R1.1 through R1.10.	The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-1 R1.1 through R1.10.	The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-1 R1.1 through R1.10.	The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-1 R1.1 through R1.10.
R1.1	The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	N/A	N/A	N/A
R1.2	The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	N/A	N/A	N/A

Requirement	Lower	Moderate	High	Severe
R1.3	The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	N/A	N/A	N/A
R1.4	The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).	N/A	N/A	N/A
R1.5	The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.	N/A	N/A	N/A
R1.6	The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.	N/A	N/A	N/A
R1.7	The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.	N/A	N/A	N/A
R1.8	The Reliability Coordinator failed to monitor planned generation dispatches.	N/A	N/A	N/A
R1.9	The Reliability Coordinator failed to monitor planned transmission or generation outages.	N/A	N/A	N/A

Requirement	Lower	Moderate	High	Severe
R1.10	The Reliability Coordinator failed to monitor contingency events.	N/A	N/A	N/A
R2	N/A	The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities.	The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements.
R3	N/A	N/A	The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans.	The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.
R4	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.

Requirement	Lower	Moderate	High	Severe
R5	N/A	N/A	The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance.	The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

Requirement	Lower	Moderate	High	Severe
R6	N/A	The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans, or the Reliability Coordinator coordinated pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in the real-time reliability analysis timeframe but failed to coordinate pending generation and transmission maintenance outages in the next-day reliability analysis timeframe.	The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations, or the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.	The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.
R7	N/A	N/A	N/A	The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.

Requirement	Lower	Moderate	High	Severe
R8	N/A	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS.	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority.	The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.
R9	N/A	N/A	N/A	The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Special Protection System that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

Requirement	Lower	Moderate	High	Severe
R10	N/A	N/A	N/A	The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.
R11	N/A	N/A	N/A	The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
R12	N/A	The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.	N/A	The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17 Retired M2 and M3; modified M9 and M12; retired M13 Made conforming changes to data retention Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Retired VSLs associated with R2, R3, R5, R16 and R17; Modified VSLs associated with R9 and R13, and R14	Revised
2	November 1, 2006	Approved by the Board of Trustees	
2	January 1, 2007	Effective Date	
2a	November 5, 2009	Approved by the Board of Trustees	
3	October 17, 2008	Approved by the Board of Trustees	
~~2a/3a~~	~~November 5, 2009~~	~~Interpretation adopted by the Board of Trustees~~	
3	March 23, 2011	Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)	
~~2a/~~3a	April 21, 2011	~~Order issued by~~Added FERC ~~approving~~approved Interpretation ~~(approval effective 5/26/11)~~	
3.1a	March 8, 2012	Errata adopted by Standards Committee; (removed outdated references in	Errata

		Measures M10 and M11 to 'Part 2' of Requirements R10 and R11)	

Appendix 1

Requirement Number and Text of Requirement
TOP-005-1 Requirement R3 Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability. *The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6:* New or degraded special protection systems. *[Underline added for emphasis.]* **IRO-005-1 Requirement R12**[1] **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected. *[Underline added for emphasis.]* **PRC-012-0 Requirements R1 and R1.3** **R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: **R1.3.** Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
Background Information for Interpretation
The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a "performance mandate." Requirement R3 defines the obligation to provide data "requested" by other reliability entities that is needed "to perform assessments and to coordinate operations." The Attachment to TOP-005-1 is provided as a guideline of what "can be shared." The Attachment is not an obligation of "what must be shared." Enforceable NERC Requirements must be explicitly contained within a given Standard's approved requirements. In this case, the standard only requires data "upon request." If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that

[1] In the current version of the Standard (IRO-005-3a), this requirement is R9.

data (including item 2.6, whether it is or is not in some undefined "degraded" state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator's obligation to be aware of conditions that may have a "significant" impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term "degraded."

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

A. Introduction

1. Title: **Operating Personnel Responsibility and Authority**

2. Number: PER-001-0.~~1~~2

3. Purpose: Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. Applicability

4.1. Transmission Operators.

4.2. Balancing Authorities.

5. Effective Date: December 10, 2009

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The job description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit or Interconnection ~~or~~ Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0.1	April 15, 2009	Replaced “position” with “job” on M1.1	Errata
0.1	April 15, 2009	Errata adopted by Standards Committee	Errata
0.1	December 10, 2009	Approved by FERC — added effective date	Update

0.2	March 8, 2012	Errata adopted by Standards Committee; (moved the word, "Interconnection" in Measure M1.4. so that it appears as the first word in the term "Interconnection Reliability Operating Limit" rather than the last word in the phrase, "System Operating Limit Interconnection)	Errata

Standard TOP-002-~~2b~~2.1b — Normal Operations Planning

A. Introduction

1. **Title:** **Normal Operations Planning**

2. **Number:** TOP-002-~~2b~~2.1b

3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

   4.3. Generator Operator.

   4.4. Load Serving Entity.

   4.5. Transmission Service Provider.

5. **Effective Date:** Immediately after approval of applicable regulatory authorities. ~~FERC Approved 12/2/09~~

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

~~**R14.1.** Changes in real and reactive output capabilities. (Retired August 1, 2007)~~

R14.1. Changes in real output capabilities.~~ (Effective August 1, 2007)~~

~~**R14.2.** Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)~~

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real ~~and reactive~~ output capabilities ~~and AVR status~~. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

3.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

3.2. Level 2: Not applicable.

3.3. Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

3.4.3 Studies not updated to reflect current system conditions as specified in R11.

3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. Levels of Non-Compliance for Generator Operators:

4.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

5.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata

Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a "unique" study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have "a" study that can be applied to it, but it is not necessary to generate a "unique" study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a "study"? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, "to determine SOLs" as used in the first sentence of Requirement R11 mean the "determination of system operating limits" or does it mean the "identification of potential SOL violations?"

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential "exceedances" of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.

Appendix 2

Requirement Number and Text of Requirement:

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

Clarification needed:

Requirement 10 is proposed to be eliminated in Project 2007-03 because it is redundant with TOP-004-0 R1, which only applies to TOP not to BA. However, that will not be effective for more than two years. In the meantime, in Requirement 10 is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

Project 2009-27: Response to Request for an Interpretation of TOP-002-2a, Requirement R10, for Florida Municipal Power Pool

The following interpretation of TOP-002-2a — Normal Operations Planning, Requirement R10, was developed by the Real-time Operations Standard Drafting Team.

Requirement Number and Text of Requirement

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

Question

In Requirement 10, is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

Response

Yes. As stated in the NERC *Glossary of Terms used in Reliability Standards*, the Balancing Authority is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area, and supporting Interconnection frequency in real time. The Balancing Authority does not possess the Bulk Electric System information necessary to manage transmission flows (MW, MVAR or Ampere) or voltage. Therefore, the Balancing Authority must follow the directions of the Transmission Operator to meet all SOLs and IROLs.

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139 FERC ¶ 61,218
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Transmission Loading Relief Reliability Standard and Curtailment Priorities — Docket No. RM10-9-000

ORDER TERMINATING PROCEEDING

(Issued June 14, 2012)

1. On January 21, 2010, the Commission issued a Notice of Inquiry[1] seeking comments regarding whether there are conflicts between the North American Electric Reliability Corporation (NERC) Reliability Standard IRO-006-4 (Reliability Coordination - Transmission Loading Relief (TLR))[2] and the curtailment priorities set forth in the Commission's *pro forma* Open Access Transmission Tariff (OATT). Comments were filed by sixteen entities, including NERC.[3] As discussed below, the Commission terminates the Notice of Inquiry in Docket No. RM10-9-000.

I. Background

2. On December 21, 2007, NERC submitted for Commission approval Reliability Standard IRO-006-4, known as the TLR procedure.[4] Reliability Standard IRO-006-4

[1] *Transmission Loading Relief Reliability Standard and Curtailment Priorities*, Notice of Inquiry, 130 FERC ¶ 61,033 (2010) (Notice of Inquiry).

[2] IRO-006-4 was replaced by IRO-006-4.1. *See North American Electric Reliability Corp.*, Docket No. RD09-9 (Dec. 10, 2009) (delegated letter order). IRO-006-5 (Transmission Loading Relief) and IRO-006-EAST-1 (TLR Procedure for the Eastern Interconnection) were approved and IRO-006-4.1 was retired on June 30, 2011. *See North American Electric Reliability Corp.*, 135 FERC ¶ 61,043 (2011).

[3] A list of the commenters is provided in Appendix A.

[4] NERC Petition, Docket No. RM08-7-000.

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modified previously-approved Reliability Standard IRO-006-3[5] and provided an interconnection-wide TLR procedure to be used to prevent or manage potential or actual System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations.[6]

3. The NRG Companies filed comments,[7] asserting that the proposed standard was not consistent with the requirements of the Commission-approved *pro forma* OATT. They asserted that, due to flaws in the Interchange Distribution Calculator (IDC),[8] firm transactions may be curtailed prior to non-firm transactions, resulting in an OATT violation. They also argued that the IDC does not take native load transactions into account when determining curtailment priority necessary to relieve congestion. Constellation Energy Commodities Group, Inc. (Constellation) filed comments in support of the NRG Companies' comments, arguing that the use of the IDC has resulted in unjust and unduly discriminatory curtailments.

4. On July 21, 2008, the Commission issued Order No. 713, which directed NERC to submit a filing providing an explanation for Requirement 1 and 1.1 of Reliability Standard IRO-006-4.[9] On March 19, 2009, the Commission approved Reliability

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[5] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[6] An SOL is the value that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. An IROL is a system operating limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely affect the reliability of the Bulk-Power System. *See* North American Electric Reliability Corp., NERC Glossary of Terms Used in Reliability Standards, *available at* http://www.nerc.com/files/Glossary_12Feb08.pdf.

[7] NRG Companies Comments, Docket No. RM08-7-000 (filed Jun. 12, 2008).

[8] The Interchange Distribution Calculator is a mechanism used by the reliability coordinators in the Eastern Interconnection to calculate the distribution of interchange transactions over specific flowgates. It includes a database of all interchange transactions and a matrix of the distribution factors for the Eastern Interconnection. *Id.* at 9.

[9] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Order No. 713, 124 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 713-A, 126 FERC ¶ 61,252 (2009), *order on reh'g*, Order No. 713-B,

(continued…)

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Standard IRO-006-4, in Order No. 713-A, and directed NERC to develop modifications to IRO-006-4 pursuant to section 215(d)(5) of the Federal Power Act (FPA).[10]

5. In a request for rehearing of Order No. 713-A, NRG Companies, Electric Power Supply Association (EPSA), and Constellation challenged the approval of Reliability Standard IRO-006-4 on several grounds.[11] They asserted that Reliability Standard IRO-006-4 violated the curtailment priorities established in Order Nos. 888[12] and 890[13] and the Commission-approved *pro forma* OATT by favoring native load transactions over interchange transactions with respect to curtailment priority. Specifically, they asserted that sections 13.6 and 14.7 of the Commission's *pro forma* OATT require that non-firm transmission service be curtailed before firm transmission service, and that firm point-to-point and network integration transmission service customers have an equal priority with the transmission provider's use of the system to deliver Network Resources

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130 FERC ¶ 61,032 (2010). The Commission sought clarification of whether the removal and transfer to NAESB of business-related requirements formerly contained in Reliability Standard IRO-006-3 would affect bulk-power system reliability, an issue unrelated to the current proceeding. Order No. 713, 124 FERC ¶ 61,071 at P 50.

[10] 16 U.S.C. § 824o(d)(5) (2006). The modifications relate to the use of the term "alone" in Requirement R1.1 and changes to the Violation Risk Factors for Requirements R1 through R4 to "high," and are not related to the issues discussed in the Notice of Inquiry. *See* Order No. 713-A, 126 FERC ¶ 61,252 at P 36, 59.

[11] NRG Companies, EPSA and Constellation, Request for Rehearing, Docket No. RM08-7-002 (filed Apr. 20, 2009).

[12] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[13] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

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to its native load. They maintained that, because of the Reliability Standard's reliance on the flawed IDC, Reliability Standard IRO-006-4 would instead direct a reliability coordinator to curtail a firm interchange transaction flowing across a constrained flowgate prior to curtailing a non-firm native network load transaction flowing across the same flowgate.

6. The Commission denied the request for rehearing as beyond the scope of the proceeding.[14] However, the Commission issued a Notice of Inquiry in Docket No. RM10-9-000 on January 21, 2010 seeking comment on whether the application of the requirements within Reliability Standard IRO-006-4 is inconsistent with *pro forma* OATT curtailment priorities.

7. Sixteen entities submitted comments in response to the Notice of Inquiry. Most commenters, including NERC, state that there is no inherent conflict between the *pro forma* OATT curtailment procedures and the TLR procedure embodied in Reliability Standard IRO-006-4.[15] Some commenters indicate that individual transmission providers' practices may not comply with the *pro forma* OATT requirements for transmission curtailment priority.[16]

II. Discussion

8. The Commission finds, based on the record before us, that the requirements of Reliability Standard IRO-006-04 have not been shown to be in conflict with the curtailment priorities of the *pro forma* OATT. Therefore, the Commission terminates the Notice of Inquiry.

9. However, the Commission notes that the flexibility provided by Reliability Standard IRO-006-4 does not relieve public utility transmission providers of their obligation to comply in all respects with both the Commission's *pro forma* OATT and the approved NERC TLR procedures. We reiterate that sections 13.6 and 14.7 of the *pro forma* OATT require that non-firm transmission service must be curtailed before firm

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[14] Order No. 713-B, 130 FERC ¶ 61,032.

[15] *See, e.g.*, EEI Comments at 2; NERC Comments at 12; and Southern Companies Comments at 4.

[16] *See, e.g.*, Basin Electric Comments at 6; DTE Energy Trading Comments at 3; Entergy Comments at 5; EPSA Comments at 11; Lafayette Comments at 4; NRG Companies Comments at 8; SPP Comments at 3; Tri-State Comments at 4-5; Union Power Comments at 10; and Xcel Comments at 11.

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transmission services, and firm point-to-point and network integration transmission service customers have an equal priority with the transmission provider's use of the system to deliver Network Resources to its native load. The Commission urges transmission providers to review their practices and the business practices standards currently under development to ensure that they are in compliance with the *pro forma* OATT.

The Commission orders:

The Notice of Inquiry in Docket No. RM10-9-000 is hereby terminated.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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Appendix A: List of Commenters

Short Name or Acronym	Commenter
Basin Electric	Basin Electric Power Cooperative
DTE Energy Trading	DTE Energy Trading, Inc.
EEI	Edison Electric Institute
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association
ISO/RTO Council	Alberta Electric System Operator, California Independent System Operator, Electric Reliability Council of Texas, the Independent Electricity System Operator of Ontario, Inc., ISO New England Inc., Midwest Independent Transmission System Operator, Inc., New York Independent System Operator, Inc., PJM Interconnection, L.L.C., Southwest Power Pool, Inc., and New Brunswick System Operator
Lafayette	Lafayette Utilities System
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NRG Companies	Louisiana Generating LLC, Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Sterling Power LLC, and NRG Power Marketing LLC
NYISO	New York Independent System Operator, Inc.
Southern Companies	Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company

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SPP	Southwest Power Pool, Inc.
Tri-State	Tri-State Generation and Transmission Association, Inc.
Union Power	Union Power Partners, L.P.
Xcel	Xcel Energy Services Inc.

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20120607-3074 FERC PDF (Unofficial) 06/07/2012

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Reliability Standards Docket No. RM12-1-000

NOTICE OF EXTENSION OF TIME

(June 7, 2012)

On June 4, 2012, the American Public Power Association, Edison Electric Institute, the Electric Power Supply Association, the Electricity Consumers Resource Council, and the National Rural Electric Cooperative Association (collectively, the Trade Associations), on behalf of their respective members, filed a motion for an extension of time to file comments in response to the Commission's Notice of Proposed Rulemaking issued April 19, 2012, in the above-referenced proceeding. *Transmission Planning Reliability Standards*, 139 FERC ¶ 61,059 (2012) (April 19 NOPR). The motion states that the Trade Associations require additional time to evaluate the April 19 NOPR, prepare necessary analyses, and develop relevant information.

Upon consideration, notice is hereby given that an extension of time for filing comments on the April 19 NOPR is granted to and including July 20, 2012.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

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20120614-3058 FERC PDF (Unofficial) 06/14/2012

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation Docket No. RD12-1-000

ERRATA NOTICE

(June 14, 2012)

On March 31, 2012, the Commission issued an "Order Approving Regional Reliability Standard" in the above-captioned proceeding. *North American Electric Reliability Corporation*, 139 FERC ¶ 61,169 (2012). Footnote 12 of the order is revised to read:

> *Western Electric Coordinating Council Qualified Transfer Path Unscheduled Flow Relief Regional Reliability Standard*, Order No. 746, 76 Fed. Reg. 16,691 (Mar. 25, 2011), 134 FERC ¶ 61,199 (2011).

Kimberly D. Bose,
Secretary.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

July 5, 2012

Joseph H. McClelland
Director, Office of Electric Reliability
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011: Docket No. AD11-9-000

Dear Mr. McClelland:

This letter is submitted in response to the Federal Energy Regulatory Commission ("FERC" or the "Commission") Office of Electric Reliability's ("OER") letter dated June 20, 2012 to Gerry Cauley regarding the status of Recommendation 11 included in the August 16, 2011 joint report issued by FERC and the North American Electric Reliability Corporation ("NERC") on the rolling blackouts and natural gas curtailments experienced in the Southwest during the February 2011 cold weather event ("Cold Weather Event"). OER's letter requested a status update on NERC's initiative to modify the Reliability Standards to address winterization and related issues, including progress made on the development of the Standard Authorization Request ("SAR"), and an anticipated timeline for filing with the Commission any proposed new or revised Reliability Standards.

OER's letter cites to Recommendation 11 in the joint report, which includes the following assessment:

> NERC staff has concluded there would be a reliability benefit from amending the EOP Reliability Standards to require Generator Owner/Operators to develop, maintain, and implement plans to winterize plants and units prior to extreme cold weather, in order to maximize generator output and availability. Accordingly, NERC intends to submit a Standard Authorization Request, the first step in the Reliability Standards development process, proposing modifications to the Reliability Standards for Emergency Preparedness and Operations.

NERC has been working diligently on the recommendations in the joint report. While OER's letter specifically requests a status of NERC's efforts on Recommendation 11, NERC has been working to address the issues raised in the report through a combination of initiatives, including lessons learned, bulletins, and possible Reliability Standards modifications. NERC's responses to the joint report are summarized below:

- A SAR has been submitted and is on the agenda for the July 2012 meeting of the Standards Committee for consideration and prioritization. The Standards Committee will determine how to prioritize the SAR within the NERC Reliability Standards Development Process. At that point, NERC will be able to better assess the timeline for completing a draft Reliability Standard, including when a draft standard could be presented to the Commission for approval. A copy of the SAR is attached as **Exhibit A**.

- NERC has issued seven (7) lessons learned and will issue additional lessons learned and advisory bulletins addressing Cold Weather this fall. These lessons detail corrective actions entities have implemented to prevent reoccurrence of the issues they experienced during the event. These lessons learned are available at http://www.nerc.com/page.php?cid=5|393. Advisory bulletins will be published in the fall during the fall maintenance cycle to remind entities of the importance of implementing the recommendations outlined in the joint report. These advisory bulletins will also reinforce some of the previous published lessons learned.

- NERC staff and FERC staff are also planning to conduct follow-up onsite assessments in the fall of 2012 – prior to the next winter season. The purpose of these assessments is to meet with entities impacted by the storm and discuss how they have implemented and institutionalized the recommendations from the report. NERC will take next steps based on information learned at these assessments, which may include the issuance of more lessons learned, bulletins, and information that can be used to inform the standards development process.

- NERC has participated in various regional and external workshops and presented information regarding the event and the recommendations.

- NERC held an industry-wide webinar to discuss the event and recommendations. A representative from Florida Power and Light shared weatherization efforts of entities in the southern tier of the United States. The presentation can be found at the same link included above, under webinars and information.

- On November 9, 2011 FERC OER staff requested three NERC Regional Entities to conduct a survey of the impacted entities – requesting data and information on how they have implemented the recommendations from the event. All three NERC Regional Entities responded with the requested information on December 9, 2011. These responses were filed in FERC Docket No. AD11-9-000.

- Finally, with respect to the recommendations in the report, each recommendation has been reviewed by a group of industry representatives from across the southeast. That group is currently formulating their table of responses that will be used to inform the comprehensive response to the Cold Weather Event, to provide input to any standards drafting team that is formed, and for any non-standards related response. A draft copy of the notes from their most recent meeting is attached as **Exhibit B**.

Please contact me with additional questions.

/s/ Herb Schrayshuen
Herb Schrayshuen
Vice President and Director, Standards and Training
North American Electric Reliability Corporation

CC: Gerry Cauley
Charles A. Berardesco

Exhibit A

Standard Authorization Request Form

Request Date: July 3, 2012		
SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Individual, Group, or Committee Name Salt River Project Electric Reliability Compliance Department	☒	New Standard Transmission Equipment Weatherization
Primary Contact (if Group or Committee) Sara McCoy	☒	Revision to existing Standard EOP-001-0 TOP-002-3 MOD-25-2
Company or Group Name Salt River Project	☐	Withdrawal of existing Standard
E-mail $ERC@Srpnet.Com	☐	Project Identified in Reliability Standards Development Plan (Project Number and Name:)
Telephone 602 236 3941	☒	Modification to NERC Glossary term or addition of new term

Brief Description of Proposed Standard Modifications/Actions (In three sentences or less, summarize the proposed actions a drafting team will be responsible for implementing.)

Standards EOP-001-0, TOP-002-3 and MOD-025-2, require an additional definition and clarification of reporting requirements to ensure that BAs and TOPs have a complete set of data concerning availability of generation facilities in order to effectively plan and manage the resources available to reliably meet load requirements under both normal and extreme weather conditions. In particular, further specificity is needed concerning reporting of weather-related constraints that affect the ability of a generating unit or plant in their footprint to operate safely and without damage to equipment.

Standards should also include requirements for GO/GOPs to create, maintain, implement and then monitor their plants winterization plan to ensure it can operate during cold weather events.

Need (Explain why the Standard is being developed or modified. Clearly indicate why the actions being proposed are needed for maintaining or improving bulk power system reliability, including an assessment of the reliability and market interface impacts. This is similar to the Purpose statement in a Reliability Standard.)

Repeated occurrences of generation shortfall in cold weather conditions in the southern US states indicate that institutionalization of cold weather preparation and reporting of generation availability is needed.

During the 2011 SW Winter Weather event, load shed was required to meet the demand due to loss of generation. During this weather event, cold weather conditions froze critical plant instrument sensors and equipment, causing generation to trip offline or not be able to come online to generate electricity when it was critically needed. Simultaneously, BAs and TOPs were basing their operations and operations planning on inaccurate generation availabilities and capacities from the GO/GOPs because the data available to them did not include availability based on the GO/GOPs Minimum Ambient Operating Temperature. This inaccurate information caused the BA and TOP to over-estimate the available generation, which resulted in the need to use load shedding to balance the actual available generation and load. Based on the Joint FERC-NERC Report, in many cases generation plants: (1) did not know their minimum operating temperature and how wind speed would lead to accelerated heat loss from the critical plant equipment ; (2) reported inaccurate minimum operating temperatures; (3) recorded minimum operating temperatures that had been set when the plant was commissioned and did not reflect current plant capability or winterization.; (4) did not utilize their cold weather maintenance practices that were in place to meet the minimum operating temperature. During the critical load time, many plants were in the mode of having to unfreeze equipment and make weather proofing modifications in real time to keep plant equipment from freezing or re-freezing. This subsequently caused generation to not be available during critical peak times,

causing the GO/GOPs, BA and TOP to be unaware of the state of the generation resources.

Goals (Describe what must be accomplished in order to meet the above need. This section would become the Requirements in a Reliability Standard.)

The goals of the SAR are:

- GO/GOPs are to define "Minimum Ambient Operating Temperature" for a generating unit including effects from wind speed.
- To require GO/GOPs to report their plant's availability based on this Minimum Ambient Operating Temperature to the BA and TOP before the winter season and during the winter season if plant availability is impacted by expected cold weather conditions.
- GO/GOPs must ensure plant winterization plans are created, maintained, implemented and monitored to help ensure generating facilities can operate at their respective Minimum Ambient Operating Temperature.

Objectives and/or Potential Future Metrics (Describe what the potential measure or criteria for success may be for determining the successful implementation of this request. Provide ideas for potential metrics to be developed and monitored in the future relative to this request, if any.)

During cold weather events, generation plants will perform (or be available) as reported for the Minimum Ambient Operating Temperature and provide their capability as determined by the generation plant to the BA and TOP

The SDT should be cautious to ensure that this Standard addresses that GO/GOPs determine their Minimum Ambient Operating Temperature and communicates plant availability to the BA/TOP based on this. This Standard should not be crafted in such a way that finds GO/GOPs in violation if a unit fails for reasons other than a cold weather event.

The SDT should also ensure that GO/GOPs are not automatically in violation when it is determined that they did determine their Minimum Ambient Operating Temperature and they did create, maintain, implement and then monitor a valid winterization plan. It will be a challenge for the SDT to exclude those GO/GOPs that upon review, did indeed implement these requirements and only experienced an unanticipated equipment problem.

Detailed Description (In three paragraphs or more, provide a detailed description of the proposed actions a drafting team will be responsible for executing so that the team can efficiently implement this request. While you will check applicability boxes on the following page, this description must include proportional identification of to whom the standard should apply among industry participants.)

The standards modifications should extend applicability to GOP/GO where needed in addition to BA and TOP. The drafting team should develop a definition for a plant/unit's Minimum Ambient Operating Temperature including specifics regarding wind speed. The drafting team

should include results based requirements for a generator to have a winterization plan appropriate for their location, climate and plant design and the resources (time, staff, budget, etc.) to implement it in order to achieve the Minimum Ambient Operating Temperature. The drafting team should include coordination expectations (next-day and real-time) by the Generator Operator with the BA/TOP should they be unable to maintain plant/unit capability at the Minimum Ambient Operating Temperature limit. The drafting team should consider a requirement for a GO/GOP to notify the BA/TOP if forecasted weather conditions will impact plant availability based on the GO/GOPs Minimum Ambient Operating Temperature.

Initial candidate standards for consideration are: EOP-001, TOP-002-3, MOD-025-2, and, but this is not an exclusive list and the Drafting Team should recommend other standards requiring modification.

OPTIONAL: Technical Analysis Performed to Support Justification (Provide the results of any technical study or analysis performed to justify this request. Alternatively, if deemed necessary, propose a technical study or analysis that should be performed prior to a related standard development project being initiated in response to this request.)

See report "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011" located at http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf.

A review has been undertaken of the individual utilities and a group review on June 14, 2012 was performed for all of the recommendations. While certain entities agree there is a problem, they also contend that in certain instances, local jurisdictions have stepped in with regulations. However this issue is a continent-wide issue and, given the history of repeated generation shortfalls in southern states (as evidenced in the FERC-NERC Report), a more permanent institutionalization through standards is needed to address, on a permanent basis, the capability of generation to operate in cold weather.

Reliability Functions

The Standard(s) May Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Entity	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-	Purchases or sells energy, capacity, and necessary reliability-related

	Selling Entity	services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard(s) comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	

4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related Projects

Project ID and Title	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	

SPP	
WECC	

Exhibit B

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Draft Notes
Cold Weather Review Team Meeting

June 13, 2012 | 8:30 a.m.-4:00 p.m. ET

NERC Atlanta Office
3353 Peachtree Road, NE
Suite 600, North Tower
Atlanta, GA 30326

1. **Welcome—Herb Schrayshuen**
   - Herb Schrayshuen welcomed and thanked attendees for participating.
2. **Review NERC Antitrust Guidelines and Open Meeting Reminder—Herb Schrayshuen**
   - Herb Schrayshuen delivered the Antitrust Guidelines and Open Meeting Reminder to participants. No questions were raised.
3. **Review of Emergency Procedures—Herb Schrayshuen**
4. **Introductions—Herb Schrayshuen**
   - Meeting attendees:
     - Brenda Hampton, EFH Luminant
     - Darrell Piatt, FERC
     - Don Jones, Texas RE
     - Greg Darnell, Southern Company Services, Inc.
     - Howard Gugel, NERC
     - J.C. Culberson, III, ERCOT
     - John Wiseman, JEA
     - Michelle D'Antuono, Occidental
     - Mike Gentry, Salt River Project
     - Randy Crissman, New York Power Authority
     - Terry Coggins, Southern Company Services, Inc.
     - Tim Ponseti, Tennessee Valley Authority
     - David Hawkins, El Paso Electric Co. (via conference call)

- Jamie Webb, Lafayette Utilities System (via conference call)
- Stephen Solis, ERCOT (via conference call)
- Janet Eschenbrenner, El Paso Electric Co. (via conference call)

5. **Review Agenda—Herb Schrayshuen**
   - One modification to the agenda was offered regarding the addition of remarks by Mike Moon on compliance processes based on controls.
6. **Objectives—Herb Schrayshuen**
   - The identified objective was to determine what, if any, standards changes were needed in light of the event and recommendations of the joint FERC/NERC Report.
7. **Project Background—Herb Schrayshuen**
   - Herb Schrayshuen provided the outline of the efforts to date and urged the need for industry "ownership" of the task to deal with this risk issue.
8. **Field Investigation Findings*—Earl Shockley**
   - Earl Shockley provided a review of the joint event analysis with the FERC and the basis for the recommendations in the report.
9. **Compliance Processes Based on Controls—Mike Moon**
   - Mike Moon offered a detailed report on a new concept being proposed which is controls- based compliance verification.
10. **Report from ERCOT*—J.C. Culberson**
    - J.C. Culberson provided a recap of the cold weather event and ERCOT's handling of the event. It was noted that during an equally demanding cold snap the following week, load and generation were balanced successfully.
11. **Northern Climate Winterization-NYPA Programs and Lessons Learned*—Randy Crissman**
    - Randy Crissman presented some examples of the winter weatherization efforts implemented by NYPA.
12. **Roundtable Discussion**
    - The group reviewed the response to recommendations prepared by ERCOT. A list of comments and reactions was developed by the group and will be used as a basis for follow-on work as outlined in the action item list below.
    - There was general recognition that a comprehensive, institutionalized response to this risk issue was needed.

- The form of that response might include changes to standards, but could likely take the form of guidance to the industry, i.e., bulletins, alerts , and pre-seasonal reminders.

13. **Action Items**

- NERC staff to prepare notes of the meeting and circulate them for comments.
- NERC staff to complete and issue a copy of the comments recorded in agenda item 12.
- NERC staff to prepare a form for extending the "matrix" with space for each region to provide input comparable to that provided by ERCOT.
- Regional representatives to take the form forward and develop inputs similar to those put forward by ERCOT.
- Next steps will be handled by email or conference call.
- Scheduling detail with due dates will be provided in future communications.

The meeting was adjourned at 3:19 p.m. ET.

*Background materials provided.

From:	Elizabeth Heenan
To:	reg_corresp_notif
Subject:	NERC: FERC e-service in Docket No. AD11-9-000: Response of NERC to FERC OER Letter Re: Winterization and Related Issues
Date:	Thursday, July 05, 2012 4:05:56 PM
Attachments:	FINAL_Response_Cold_Weather_Event_complete.pdf

Good Afternoon,

Attached please find a NERC's Response to the FERC Office of Electric Reliability Letter to NERC regarding NERC's initiative to modify the Reliability Standards to address winterization and related issues, filed today with the Federal Energy Regulatory Commission in Docket No. AD11-9-000.

This email constitutes service pursuant to Rule 2010 of the Commission's regulations.

Thank you,

Elizabeth A. Heenan

Legal Assistant
North American Electric Reliability Corporation
1325 G Street NW, Suite 600
Washington, DC 20005
Cell: (202) 420-8795
Direct: (202) 644-8040

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Y

May 23, 2012

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: *North American Electric Reliability Corporation*
Docket No._____

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC" or "the Commission") regulations seeking approval of an interpretation to Requirement R1.1 to Reliability Standard CIP-006-4,[1] as set forth in **Exhibit A** to this petition, to become effective concurrent with the date of a FERC Order approving this petition.

This interpretation was approved by the NERC Board of Trustees on February 9, 2012. Upon approval, the standard will be referred to as CIP-006-3d or CIP-006-4d, whichever version of the standard is in effect at the time of FERC approval.[2]NERC's petition consists of the following:

[1] This interpretation applies to Versions 1, 2, 3, and 4 of the CIP-006 standard. For purposes of this filing, the standard will be referred to as CIP-006-4.
[2] At the time this request for interpretation was submitted to NERC, Version 1 of the CIP standards was in effect. The request was therefore processed referencing CIP-006-1. Subsequently, Versions 2, 3 and 4 of the CIP standards were approved by FERC. However, the changes in Versions 2, 3, and 4, relative to Version 1 of CIP-006, are not material to the substance of the interpretation request. Given that Version 3

- This transmittal letter;
- A table of contents for the filing;
- A narrative description explaining the interpretation and how it meets the reliability goal of the standard;
- Interpretation of Requirement R1.1 of CIP-006-4 (**Exhibit A**);
- Reliability Standard CIP-006-3d, that includes the appended interpretations of Requirement R1.1, submitted for approval (**Exhibit B1**);
- Reliability Standard CIP-006-4d, that includes the appended interpretations of Requirement R1.1, submitted for approval (**Exhibit B2**);
- Consideration of Comments for interpretations to Requirements R1.1 of CIP-006-4 (**Exhibit C**);
- The complete development record of the interpretation Requirement R1.1 of CIP-006-4 (**Exhibit D**); and
- A roster of the interpretation drafting team for the interpretations of Requirement R1.1 of CIP-006-4 **(Exhibit E**).

For the reasons stated above and in this petition, NERC respectfully requests that the Commission approve the interpretation presented herein for approval.

Respectfully submitted,

/s/ Willie L. Phillips
Willie L. Phillips
Attorney for North American Electric Reliability Corporation

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is currently-effective, and Version 4 will become effective on April 1, 2014, NERC will append the requested interpretation to Version 3 or Version 4 of the CIP-006 standard, whichever is in effect at the time of FERC approval of this interpretation, in lieu of Version 1. *See Order Approving Revised Reliability Standards for Critical Infrastructure Protection and Requiring Compliance Filing*, 128 FERC ¶ 61,291 (September 30, 2009); *Order on Compliance*, 130 FERC ¶ 61,271 (2010) (March 31, 2010); *Version 4 Critical Infrastructure Protection Reliability Standards*, Order No. 761, 139 FERC ¶ 61,058 (April 19, 2012).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket No. RM-__-000)**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF INTERPRETATION TO RELIABILITY STANDARD CIP-006 – CYBER SECURITY — PHYSICAL SECURITY OF CRITICAL CYBER ASSETS

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May 23, 2012

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Exhibit A — Interpretation of Requirement R1.1 of CIP-006-4

Exhibit B1 —Reliability Standard CIP-006-3, that includes the appended interpretation of Requirement R1.1, submitted for approval

Exhibit B2 —Reliability Standard CIP-006-4, that includes the appended interpretation of Requirement R1.1, submitted for approval

Exhibit C — Consideration of Comments for interpretation to Requirement R1.1 of CIP-006-4

Exhibit D — Complete Record of Development of the Interpretation of Requirement R1.1 of CIP-006-4

Exhibit E — Roster of the interpretation drafting team for the Interpretation of Requirement R.1.1 of CIP-006-4

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[3] hereby requests the Federal Energy Regulatory Commission ("FERC" or "Commission") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[4] and Section 39.5 of FERC's Regulations,[5] a proposed interpretation to Reliability Standard CIP-006-4[6] — Cyber Security — Physical Security of Critical Cyber Assets, Requirement R1.1, to become effective concurrent with the date of a FERC Order approving this petition.[7]

No modification to the language contained in this specific requirement is being proposed through the interpretation. The NERC Board of Trustees approved the interpretation to CIP-006-4 on February 9, 2012. NERC requests that FERC approve the interpretation to Reliability Standard CIP-006-3 or CIP-006-4, to cover the different versions of the standard as they currently exist or become effective, and make the interpretation effective immediately upon approval in accordance with FERC's procedures.

Upon Commission approval of the interpretation, the standard will be referred to as CIP-006-3d or CIP-006-4d — Cyber Security — Physical Security of Critical Cyber Assets, whichever version of the standard is in effect at the time of FERC approval. For ease of reference, the interpretation will be referred to as CIP-006-4d in this filing.

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[3] NERC was certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000 *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[4] 16 U.S.C. 824o (2006).

[5] 18 C.F.R. § 39.5 (2011).

[6] The proposed interpretation applies to versions 1, 2, 3, and 4 of the standard. For purposes of this filing, the standard will be referred to as CIP-006-4.

[7] Capitalized terms not otherwise defined, shall have the meaning set forth in the *NERC Glossary of Terms Used in NERC Reliability Standards*, available at: http://www.nerc.com/files/Glossary_of_Terms.pdf.

Exhibit A to this petition sets forth the interpretation of Requirement R1.1 to CIP-006-4. **Exhibit B1** to this petition contains proposed Reliability Standard CIP-006-3d, which includes the appended interpretation of Requirement R1.1. **Exhibit B2** to this petition contains proposed Reliability Standard CIP-006-4d, which includes the appended interpretation of Requirement R1.1. **Exhibit C** contains the drafting team's consideration of industry comments for the interpretation to Requirement R1.1. **Exhibit D** contains the complete development history of the Interpretation of Requirement R1.1 of CIP-006-4. **Exhibit E** contains the roster of the interpretation drafting team that drafted the interpretation of Requirement R1.1.

NERC is also filing this interpretation with applicable governmental authorities in Canada.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[8]

Gerald W. Cauley
President and Chief Executive Officer
3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326-1001

David N. Cook*
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III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[9] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the bulk power system, and with the duties of certifying an electric reliability organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. Section 215 states that all users, owners and operators of the bulk power system in the United States will be subject to FERC-approved Reliability Standards.

b. Basis for Approval of Proposed Reliability Standard Interpretation

[8] Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

[9] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005) (codified at 16 U.S.C. § 824o).

The proposed Reliability Standard contains an interpretation of a requirement within a Commission-approved Reliability Standard, but does not represent a new or modified Reliability Standard. The proposed Reliability Standard interpretation provides additional clarity with regard to the intent of the Reliability Standard. Therefore, NERC requests that the Commission approve the proposed interpretation.

c. Reliability Standards Development Procedure and Interpretation

All persons who are directly or materially affected by the reliability of the North American bulk power system are permitted to request an interpretation of a Reliability Standard, as discussed in NERC's *Standard Processes Manual*,[10] which is incorporated into the NERC Rules of Procedure as Appendix 3A.

The process for responding to a valid request for interpretation requires NERC to assemble a team with the relevant expertise to address the interpretation request. The interpretation drafting team is then required to draft a response to the request for interpretation and then present that response for industry ballot. If approved by the ballot pool and the NERC Board of Trustees, the interpretation is appended to the Reliability Standard and filed for approval with FERC and applicable governmental authorities in Canada. And once the affected Reliability Standard undergoes its next substantive revision, the interpretation will be incorporated into the Reliability Standard, as appropriate.

[10] FERC approved the new *Standard Processes Manual* in the *Order Approving Petition and Directing Compliance Filing*, (132 FERC ¶ 61,200 (2010), which replaced NERC's *Reliability Standards Development Procedure Version 7* in its entirety. NERC developed these interpretations in accordance with the *Reliability Standards Development Procedure Version 7* until the *Standard Processes Manual* was approved on September 3, 2010. NERC's *Reliability Standards Development Procedure* is available at: http://www.nerc.com/fileUploads/File/Standards/RSDP_V6_1_12Mar07.pdf. The Standard Processes Manual is available at: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20100903.pdf.

The standing CIP interpretation drafting team was appointed to develop the response to the instant request for interpretation regarding Requirement R1.1 of CIP-006-4. The proposed interpretation included as **Exhibit A** was approved by the ballot pool on December 19, 2011, with a ballot pool quorum of 88.02 percent and weighted segment approval of 96.04 percent. It was approved by the NERC Board of Trustees on February 9, 2012.

IV. Proposed Reliability Standard CIP-006-4 Cyber Security — Physical Security of Critical Cyber Assets Requirement R1.1

The Commission approved Reliability Standard CIP-006-1 in Order No. 706,[11] Reliability Standard CIP-006-2 in the September 30, 2009 Order,[12] Reliability Standard CIP-006-3 in the March 31, 2010 Order, [13] and Reliability Standard CIP-006-4 in Order No. 761.[14]

This filing includes the proposed Reliability Standard CIP-006-3d that contains the appended interpretation in **Exhibit B1**, and proposed Reliability Standard CIP-006-4d that contains the appended interpretation in **Exhibit B2**. In Section IV(a), below, NERC summarizes the justification for the proposed interpretation of Requirements R1.1 of the standard, and explains the development of the interpretation. Section IV(b) describes the stakeholder ballot results and provides an explanation of how stakeholder comments were considered and addressed by the interpretation drafting team assembled to develop the interpretation. The interpretation drafting team's considerations of comments for the

[11] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040, at PP 24 and 581 (2008), *order on clarification*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, 126 FERC ¶ 61,229 (2009).
[12] *Order Approving Revised Reliability Standards for Critical Infrastructure Protection and Requiring Compliance Filing*, 128 FERC ¶ 61,291 (September 30, 2009).
[13] *Order on Compliance*, 130 FERC ¶ 61,271(March 31, 2010).
[14] *Version 4 Critical Infrastructure Protection Reliability Standards*, Order No. 761, 139 FERC ¶ 61,058 (April 19, 2012).

interpretation is contained in **Exhibit C**. The complete development record for the interpretation, set forth in **Exhibit D,** includes the request for the interpretation, the response to the request for the interpretation, the ballot pool, and the final ballot results by registered ballot body members, stakeholder comments received during the balloting and an explanation of how those comments were considered. **Exhibit E** contains the roster of the team members who developed the proposed interpretation.

a. Justification for Approval of Interpretation

The stated purpose of Reliability Standard CIP-006-4 — Cyber Security — Physical Security of Critical Cyber Assets is to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Requirement R1 of CIP-006-4 provides:

> **R1.** Physical Security Plan —The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:
>
> > **R1.1.** All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

In April 2008, Progress Energy requested an interpretation of Requirement R1 of CIP-006-1.[15] Specifically, Progress Energy sought clarification with respect to the following language in CIP-006-4, Requirement R1.1:

[15] At the time this request for interpretation was submitted to NERC, Version 1 of the CIP standards was in effect. The request was therefore processed referencing CIP-006-1. Subsequently, Versions 2, 3 and 4 of the CIP standards were approved by FERC. However, the changes in Versions 2, 3, and 4, relative to Version 1 of CIP-006, are not material to the substance of the interpretation request. Given that Version 3 is currently-effective, and Version 4 will become effective on April 1, 2014, NERC will append the requested interpretation to Version 3 or Version 4 of the CIP-006 standard, whichever is in effect at the time of FERC approval of this interpretation, in lieu of Version 1. *See Order Approving Revised Reliability Standards for Critical Infrastructure Protection and Requiring Compliance Filing*, 128 FERC ¶ 61,291

Request:

Progress Energy requests a formal interpretation of CIP-006-1Requirement R1.1.

In CIP-006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

> *R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,*
> *R3.2. The Cyber Asset uses a routable protocol within a control center; or,*
> *R3.3. The Cyber Asset is dial-up accessible.*

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

In response to Progress Energy's interpretation request, the interpretation drafting team developed, and the industry stakeholders approved, the following interpretation:

(September 30, 2009); *Order on Compliance,* 130 FERC ¶ 61,271 (2010) (March 31, 2010); *Version 4 Critical Infrastructure Protection Reliability Standards*, Order No. 761, 139 FERC ¶ 61,058 (April 19, 2012).

Response:

CIP-006-1, Requirement R1.1 applies to "Cyber Assets," and the first test in determining whether it applies to wiring is to determine whether wiring is a "Cyber Asset." The definition of "Cyber Asset" in the NERC Glossary of Terms Used in Reliability Standards includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," Requirement R1.1 of CIP-006-1 does not apply to wiring.

This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 1. The interpretation in CIP-006-3c, appendix 1, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).

The interpretation of Requirement R1.1 of CIP-006-4 is consistent with the stated purpose of the Reliability Standard, which is to ensure that Critical Cyber Assets are protected. As part of a physical security program, the standard requires the creation and maintenance of a Physical Security Plan that addresses protection of Cyber Assets within a Physical Security Perimeter. In this context, the interpretation discusses the distinction between a Cyber Asset and underlying components of Cyber Assets that are not themselves classified Cyber Assets. Since the requirement only applies to a Cyber Asset, and wiring is not a Cyber Asset, the requirement does not apply to wiring. Accordingly, the interpretation clarifies that Requirement R1.1 of CIP-006-4 does not apply to wiring.

In finding that wiring is not a Cyber Asset, and thus not subject to the requirement, the interpretation drafting team determined that the definition of Cyber Asset in the *Glossary of Terms Used in NERC Reliability Standards* does not include communication mediums (*i.e.*, wiring).[16]

[16] *NERC Glossary of Terms Used in NERC Reliability Standards*, at p. 14, available at: http://www.nerc.com/files/Glossary_of_Terms.pdf.

A "communication network," which is included in the definition of a Cyber Asset, is typically a set of devices and a population of data, but not the wires or any other supporting component. For example, as noted by members of the interpretation drafting team, a "communication network" uses electricity and power cables. Although electricity and power cables are essential components of a communication network, they are not classified as Cyber Assets. Moreover, while the term "data" is included in the definition of Cyber Asset, the use of wiring to transmit data does not automatically transform wiring into a Cyber Asset.[17] Even so, NERC notes that CIP-005 requires the identification and protection of the ESP inside which all Critical Cyber Assets reside, as well as all access points on the perimeter.

Assuming *arguendo* that "wiring" is a Cyber Asset, wiring would then be subject to all Reliability Standards that apply to Cyber Assets. Such a reading of NERC's Cyber Asset definition would lead to an unintended application of the CIP standards and the wasting of limited industry resources. Therefore, the proposed interpretation is consistent with the definition of Cyber Asset and the Reliability Standard's purpose.[18]

b. Summary of the Reliability Standard Development Proceedings

NERC presented the interpretation of CIP-006-4, Requirement R1.1 for a first initial ballot from August 7, 2008, through August 16, 2008, and achieved a quorum of 88.18 percent with a weighted affirmative approval of 21.52 percent. There were 142

[17] *Id*.
[18] This interpretation also clarifies a separate question from a previously-approved interpretation to the same requirement. The proposed interpretation is limited to whether the requirement applies at all (in this case, to "wiring"). The previously approved interpretation assumes that the standard applies, and then provides clarity on the "alternative measures" component of CIP-006-4, Requirement R1.1, after determining that a fully enclosed six-wall border cannot be established around the applicable Cyber Asset.

negative ballots submitted in the initial ballot, and 97 of those ballots included a comment, which initiated the need for another initial ballot.

A second draft interpretation was developed and posted for initial ballot from November 30, 2009, to October 12, 2009. Stakeholders supported the draft interpretation, which achieved a quorum of 79.92 percent with a weighted affirmative approval of 74.47 percent. There were 46 negative ballots submitted in the second initial ballot, and 30 of those ballots included a comment; however, work on the interpretation was delayed based on reprioritization of the total standards workload in accordance with guidance from the NERC Board of Trustees issued November 2009.

In April 2011, the Standards Committee approved and issued the *NERC Guidelines for Interpretation Drafting Teams*, and the Standards Committee directed that work resume on the interpretation.[19] A project team assembled from members of the CIP interpretation drafting team reviewed and responded to the comments received during the last successive ballot and made revisions to the interpretation. The interpretation drafting team ultimately determined that the second draft interpretation did not conform to the new guidelines. Consequently, the interpretation drafting team revised the interpretation to be limited to the question asked: whether CIP-006-1, Requirement R1.1, applies to the aspects of wiring that comprises the ESP.

An updated draft of the interpretation was posted for successive ballot on October 12, 2011, with the ballot occurring from November 11 through November 21, 2011. The ballot achieved a 95.99% approval, with a quorum of 83.53%. There were 9 negative

[19] *NERC Guidelines for Interpretation Drafting Teams*, available at: http://www.nerc.com/files/Guidelines_for_Interpretation_Drafting_Teams_Approved_April_2011.pdf.

ballots submitted in the successive ballot, and 5 of those ballots included a comment, which initiated the need for a recirculation ballot.

A recirculation ballot was held from December 9, 2011 to December 19, 2011, and the interpretation was approved by stakeholders, achieving 96.04 percent approval with a quorum of 88.02 percent.

As demonstrated in the summary of comments presented below, some commenters noted disagreement with the standard drafting team's interpretation that wiring is not a Cyber Asset. Some balloters commented on more than one issue. More specifically, the reasons cited for the negative ballots included the following:

- 1 balloter did not believe the Request for Interpretation was clear enough to formulate an interpretation and that Progress Energy should have been afforded an opportunity to reformulate its question. The interpretation drafting team and majority of balloters agree, however, that the interpretation was able to provide clarity to the meaning of the requirement through its analysis.
- 1 balloter indicated that the interpretation did not provide enough clarity and should be addressed in future versions of the standard. The interpretation drafting team and balloters agree, however, that the interpretation was able to provide clarity to the meaning of the requirement through its analysis.
- 1 balloter indicated that the interpretation is flawed because it defines wiring as a Cyber Asset and expands the requirement, and that the "six-wall" border issue should not be addressed. It is presumed that this

balloter perhaps read an earlier draft of the interpretation when commenting.

- 1 balloter noted that a wire is the transport medium for the data, and data is a Cyber Asset. CIP-006-3, R1.1, requires data to be protected; to protect the data, the wire must also be protected. The interpretation drafting team determined that wire is an underlying component of a Cyber Asset and therefore not a Cyber Asset), which is consistent with CIP-006-3c, R1.1's requirement to protect data.
- 1 balloter noted that wiring is an essential component of the hardware comprising a network, further supporting the need to protect the wiring. The interpretation drafting team noted that it is outside the scope of the language of the definition of "Cyber Asset," and CIP-006-4c, R1.1's application is limited to Cyber Assets.

c. Future Action

Reliability Standard CIP-006-4c was approved by Commission on April 19, 2012, in Docket No. RM11-11-000. Upon Commission approval of the requested interpretation, the interpretation shall remain in effect until such time as the interpretation can be incorporated into a future revision of the standard.

V. CONCLUSION

NERC respectfully requests that FERC approve the interpretation to FERC-approved Reliability Standard CIP-006-4— Cyber Security — Physical Security of Critical Cyber Assets, Requirement R1.1, as set out in **Exhibit A**, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of FERC's regulations. NERC requests that this interpretation be made effective immediately upon issuance of FERC's order in this proceeding.

Respectfully submitted,

/s/ *Willie L. Phillips*

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 23rd day of May, 2012.

/s/ Willie L. Phillips
Willie L. Phillips
Attorney for North American Electric Reliability Corporation

Exhibit A

Interpretation of Requirement R1.1 of CIP-006-4

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:
Progress Energy requests a formal interpretation of CIP-006-1. R1.1.

In CIP_006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

The following revised interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the CIP Interpretation Drafting Team's Project 2008-10 Interpretation Drafting Team in response to industry comments received from the second initial ballot:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Revised Response:

CIP-006-1, Requirement R1.1 applies to "Cyber Assets," and the first test in determining whether it applies to wiring is to determine whether wiring is a "Cyber Asset."
The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," Requirement R1.1 of CIP-006-1 does not apply to wiring.

This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 1. The interpretation in CIP-006-3c, appendix 1, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).

Exhibit B1

Reliability Standard CIP-006-3, that includes the appended interpretation of Requirement R1.1, submitted for approval

A. Introduction

1. Title: Cyber Security — Physical Security of Critical Cyber Assets

2. Number: CIP-006-3d

3. Purpose: Standard CIP-006-3 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-006-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Interchange Authority

4.1.4 Transmission Service Provider

4.1.5 Transmission Owner

4.1.6 Transmission Operator

4.1.7 Generator Owner

4.1.8 Generator Operator

4.1.9 Load Serving Entity

4.1.10 NERC

4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-006-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.

R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.

R1.6. A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:

R1.6.1. Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.

R1.6.2. Continuous escorted access of visitors within the Physical Security Perimeter.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized

access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-3. One or more of the following monitoring methods shall be used:

- Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.

R7. Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not make exceptions in its cyber security policy to the creation, documentation, or maintenance of a physical security plan.

1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-3 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by NERC Board of Trustees	
1	January 18, 2008	FERC Order issued approving CIP-006-1	
	February 12, 2008	Interpretation of R1 and Additional Compliance Information Section 1.4.4 adopted by NERC Board of Trustees	Project 2007-27
2		Updated version number from -1 to -2 Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.	Project 2008-06
2	May 6, 2009	Adopted by NERC Board of Trustees	
	August 5, 2009	Interpretation of R4 adopted by NERC Board of Trustees	Project 2008-15
2	September 30, 2009	FERC Order issued approving CIP-006-2	
3	November 18, 2009	Updated version number from -2 to -3 Revised Requirement 1.6 to add a Visitor Control program component to the Physical Security Plan, in response to FERC order issued September 30, 2009. In Requirement R7, the term "Responsible Entity" was capitalized. Updated Requirements R1.6.1 and R1.6.2 to be responsive to FERC Order RD09-7	Project 2009-21
3	December 16, 2009	Adopted by NERC Board of Trustees	
	February 16, 2010	Interpretation of R1 and R1.1 adopted by NERC Board of Trustees	Project 2009-13
3	March 31, 2010	FERC Order issued approving CIP-006-3	
2a/3a	July 15, 2010	FERC Order issued approving the Interpretation of R1 and R1.1. Updated version numbers from -2/-3 to -2a/-3a.	
4	January 24, 2011	Adopted by NERC Board of Trustees	
3c/4c	May 19, 2011	FERC Order issued approving two interpretations: 1) Interpretation of R1 and Additional Compliance Information Section 1.4.4; and 2) Interpretation of R4.	

		Updated version number from -3/-4 to -3c/-4c.	
3d/4d	February 9, 2012	Interpretation of R1.1 adopted by NERC Board of Trustees	Project 2008-10

Appendix 1

Requirement Number and Text of Requirement
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following: R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.
Question
If a completely enclosed border cannot be created, what does the phrase, "to control physical access" require? Must the alternative measure be physical in nature? If so, must the physical barrier literally prevent physical access e.g. using concrete encased fiber, or can the alternative measure effectively mitigate the risks associated with physical access through cameras, motions sensors, or encryption? Does this requirement preclude the application of logical controls as an alternative measure in mitigating the risks of physical access to Critical Cyber Assets?
Response
For Electronic Security Perimeter wiring external to a Physical Security Perimeter, the drafting team interprets the Requirement R1.1 as not limited to measures that are "physical in nature." The alternative measures may be physical or logical, on the condition that they provide security equivalent or better to a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.

Appendix 2

Interpretation of Requirement R1.1.

Request: *Are dial-up RTUs that use non-routable protocols and have dial-up access required to have a six-wall perimeters or are they exempted from CIP-006-1 and required to have only electronic security perimeters? This has a direct impact on how any identified RTUs will be physically secured.*

Interpretation:

Dial-up assets are Critical Cyber Assets, assuming they meet the criteria in CIP-002-1, and they must reside within an Electronic Security Perimeter. However, physical security control over a critical cyber asset is not required if that asset does not have a routable protocol. Since there is minimal risk of compromising other critical cyber assets dial-up devices such as Remote Terminals Units that do not use routable protocols are not required to be enclosed within a "six-wall" border.

CIP-006-1 — Requirement 1.1 requires a Responsible Entity to have a physical security plan that stipulate cyber assets that are within the Electronic Security Perimeter also be within a Physical Security Perimeter.

R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

CIP-006-1 — Additional Compliance Information 1.4.4 identifies dial-up accessible assets that use non-routable protocols as a special class of cyber assets that are not subject to the Physical Security Perimeter requirement of this standard.

1.4. Additional Compliance Information

1.4.4 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006 for that single access point at the dial-up device.

Appendix 3

The following interpretation of CIP-006-1a — Cyber Security — Physical Security of Critical Cyber Assets, Requirement R4 was developed by the standard drafting team assigned to Project 2008-14 (Cyber Security Violation Severity Levels) on October 23, 2008.

Request:

1. *For physical access control to cyber assets, does this include monitoring when an individual leaves the controlled access cyber area?*
2. *Does the term, "time of access" mean logging when the person entered the facility or does it mean logging the entry/exit time and "length" of time the person had access to the critical asset?*

Interpretation:

No, monitoring and logging of access are only required for ingress at this time. The term "time of access" refers to the time an authorized individual enters the physical security perimeter.

Requirement Number and Text of Requirement

R4. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

R4.1. Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.

R4.2. Video Recording: Electronic capture of video images of sufficient quality to determine identity.

R4.3. Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.

Appendix 4[1]

Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:

Progress Energy requests a formal interpretation of CIP-006-1. R1.1.

In CIP_006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

- *R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,*
- *R3.2. The Cyber Asset uses a routable protocol within a control center; or,*
- *R3.3. The Cyber Asset is dial-up accessible.*

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets

R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

The following revised interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the CIP Interpretation Drafting Team's Project 2008-10 Interpretation Drafting Team in response to industry comments received from the second initial ballot:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Revised Response:

CIP-006-1, Requirement R1.1 applies to "Cyber Assets," and the first test in determining whether it applies to wiring is to determine whether wiring is a "Cyber Asset."

The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," Requirement R1.1 of CIP-006-1 does not apply to wiring.

This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 1. The interpretation in CIP-006-3c, appendix 1, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).

Exhibit B2

Reliability Standard CIP-006-4, that includes the appended interpretation of Requirement R1.1, submitted for approval

A. Introduction

1. Title: Cyber Security — Physical Security of Critical Cyber Assets

2. Number: CIP-006-4d

3. Purpose: Standard CIP-006-4 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-4 should be read as part of a group of standards numbered Standards CIP-002-4 through CIP-009-4.

4. Applicability:

4.1. Within the text of Standard CIP-006-4, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Interchange Authority

4.1.4 Transmission Service Provider

4.1.5 Transmission Owner

4.1.6 Transmission Operator

4.1.7 Generator Owner

4.1.8 Generator Operator

4.1.9 Load Serving Entity

4.1.10 NERC

4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-006-4:

4.2.1 Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 In nuclear plants, the systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F. R. Section 73.54

4.2.4 Responsible Entities that, in compliance with Standard CIP-002-4, identify that they have no Critical Cyber Assets

5. Effective Date: The first day of the eighth calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the ninth calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.

R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-4 Requirement R4.

R1.6. A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:

R1.6.1. Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.

R1.6.2. Continuous escorted access of visitors within the Physical Security Perimeter.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4 Requirements R2 and R3; Standard CIP-006-4 Requirements R4 and R5; Standard CIP-007-4; Standard CIP-008-4; and Standard CIP-009-4.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-4. One or more of the following monitoring methods shall be used:

- Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.

R7. Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-4.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.2. The RE shall serve as the CEA with the following exceptions:

1.2.1 For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

1.2.2 For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2.3 For Responsible Entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2.4 For the ERO, a third-party monitor without vested interest in the outcome for the ERO shall serve as the Compliance Enforcement Authority.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not make exceptions in its cyber security policy to the creation, documentation, or maintenance of a physical security plan.

1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-4 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by NERC Board of Trustees	
1	January 18, 2008	FERC Order issued approving CIP-006-1	
	February 12, 2008	Interpretation of R1 and Additional Compliance Information Section 1.4.4 adopted by NERC Board of Trustees	Project 2007-27
2		Updated version number from -1 to -2 Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.	Project 2008-06
2	May 6, 2009	Adopted by NERC Board of Trustees	
	August 5, 2009	Interpretation of R4 adopted by NERC Board of Trustees	Project 2008-15
2	September 30, 2009	FERC Order issued approving CIP-006-2	
3	November 18, 2009	Updated version number from -2 to -3 Revised Requirement 1.6 to add a Visitor Control program component to the Physical Security Plan, in response to FERC order issued September 30, 2009. In Requirement R7, the term "Responsible Entity" was capitalized. Updated Requirements R1.6.1 and R1.6.2 to be responsive to FERC Order RD09-7	Project 2009-21
3	December 16, 2009	Adopted by NERC Board of Trustees	
	February 16, 2010	Interpretation of R1 and R1.1 adopted by NERC Board of Trustees	Project 2009-13
3	March 31,	FERC Order issued approving CIP-006-3	

	2010		
2a/3a	July 15, 2010	FERC Order issued approving the Interpretation of R1 and R1.1. Updated version numbers from -2/-3 to -2a/-3a.	
4	January 24, 2011	Adopted by NERC Board of Trustees	
3c/4c	May 19, 2011	FERC Order issued approving two interpretations: 1) Interpretation of R1 and Additional Compliance Information Section 1.4.4; and 2) Interpretation of R4. Updated version number from -3/-4 to -3c/-4c.	
3d/4d	February 9, 2012	Interpretation of R1.1 adopted by NERC Board of Trustees	Project 2008-10

Appendix 1

Requirement Number and Text of Requirement
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following: R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.
Question
If a completely enclosed border cannot be created, what does the phrase, "to control physical access" require? Must the alternative measure be physical in nature? If so, must the physical barrier literally prevent physical access e.g. using concrete encased fiber, or can the alternative measure effectively mitigate the risks associated with physical access through cameras, motions sensors, or encryption? Does this requirement preclude the application of logical controls as an alternative measure in mitigating the risks of physical access to Critical Cyber Assets?
Response
For Electronic Security Perimeter wiring external to a Physical Security Perimeter, the drafting team interprets the Requirement R1.1 as not limited to measures that are "physical in nature." The alternative measures may be physical or logical, on the condition that they provide security equivalent or better to a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.

Appendix 2

Interpretation of Requirement R1.1.

Request: *Are dial-up RTUs that use non-routable protocols and have dial-up access required to have a six-wall perimeters or are they exempted from CIP-006-1 and required to have only electronic security perimeters? This has a direct impact on how any identified RTUs will be physically secured.*

Interpretation:

Dial-up assets are Critical Cyber Assets, assuming they meet the criteria in CIP-002-1, and they must reside within an Electronic Security Perimeter. However, physical security control over a critical cyber asset is not required if that asset does not have a routable protocol. Since there is minimal risk of compromising other critical cyber assets dial-up devices such as Remote Terminals Units that do not use routable protocols are not required to be enclosed within a "six-wall" border.

CIP-006-1 — Requirement 1.1 requires a Responsible Entity to have a physical security plan that stipulate cyber assets that are within the Electronic Security Perimeter also be within a Physical Security Perimeter.

R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

CIP-006-1 — Additional Compliance Information 1.4.4 identifies dial-up accessible assets that use non-routable protocols as a special class of cyber assets that are not subject to the Physical Security Perimeter requirement of this standard.

1.4. Additional Compliance Information

1.4.4 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006 for that single access point at the dial-up device.

Appendix 3

The following interpretation of CIP-006-1a — Cyber Security — Physical Security of Critical Cyber Assets, Requirement R4 was developed by the standard drafting team assigned to Project 2008-14 (Cyber Security Violation Severity Levels) on October 23, 2008.

Request:

1. *For physical access control to cyber assets, does this include monitoring when an individual leaves the controlled access cyber area?*
2. *Does the term, "time of access" mean logging when the person entered the facility or does it mean logging the entry/exit time and "length" of time the person had access to the critical asset?*

Interpretation:

No, monitoring and logging of access are only required for ingress at this time. The term "time of access" refers to the time an authorized individual enters the physical security perimeter.

Requirement Number and Text of Requirement

R4. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

R4.1. Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.

R4.2. Video Recording: Electronic capture of video images of sufficient quality to determine identity.

R4.3. Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.

Appendix 4[1]

Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:

Progress Energy requests a formal interpretation of CIP-006-1. R1.1.

In CIP_006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

- *R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,*
- *R3.2. The Cyber Asset uses a routable protocol within a control center; or,*
- *R3.3. The Cyber Asset is dial-up accessible.*

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets

R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

The following revised interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the CIP Interpretation Drafting Team's Project 2008-10 Interpretation Drafting Team in response to industry comments received from the second initial ballot:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter***.** *Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Revised Response:

CIP-006-1, Requirement R1.1 applies to "Cyber Assets," and the first test in determining whether it applies to wiring is to determine whether wiring is a "Cyber Asset."

The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," Requirement R1.1 of CIP-006-1 does not apply to wiring.

This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 1. The interpretation in CIP-006-3c, appendix 1, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).

Exhibit C

Consideration of Comments for interpretation to Requirement R1.1 of CIP-006-4

Project 2008-10
Interpretation - CIP-006 - Cyber Security — Physical Security of Cyber Security Assets

Registered Ballot Body

Related Files

Status:
A recirculation ballot of the interpretation ended on December 19, 2011. The interpretation was approved by the ballot pool with a quorum of 88.02% and weighted segment approval of 96.04%. The interpretation will be presented to the NERC Board of Trustees for adoption in February 2012 and if adopted, filed with regulators for approval.

Background:
Progress Energy asked if Electronic Security Perimeter wiring external to a Physical Security Perimeter must be protected within a six-wall boundary.

Draft	Action	Dates	Results	Consideration of Comments
Interpretation of CIP-006-x R1 for Progress Energy Draft Interpretation Clean | Redline to Last Posting **Supporting Materials:** CIP-006-3C	Recirculation Ballot Info>> Vote>>	12/09/11 - 12/19/11 (closed)	Summary>> Full Record>>	
Interpretation of CIP-006-x R1 for Progress Energy Draft Interpretation Clean | Redline to Last Posting **Supporting Materials:** Unofficial Comment Form CIP-006-3C	Successive Ballot Vote>>	11/11/11 - 11/21/11 (closed)	Summary>> Full Record>>	
	Formal Comment Period Info>>	10/12/11 - 11/21/11 (closed)		Consideration of Comments**(3)**

	Submit Comments>>			
	Join Ballot Pool>>	10/12/11 - 11/10/11 (closed)		
Progress Energy CIP-006-1, Requirement R1.1 - Automatic Generation Control Revised Interpretation Request for Interpretation	Initial Ballot Info>> | Vote>>	09/30/09 – 10/12/09 (closed)	Summary>> Full Record>>	Consideration of Comments**(2)**
	Pre-ballot Review Info>> | Join>>	08/31/09 – 09/30/09 (closed)		
Progress Energy CIP-006-1, Requirement R1.1 - Automatic Generation Control Interpretation Request for Interpretation	Initial Ballot Vote>>	08/07/08 – 08/16/08 (closed)	Full Record>>	Consideration of Comments**(1)**
	Pre-ballot Window Info>> | Join>>	07/08/08 – 08/07/08 (closed)		
To download a file click on the file using your right mouse button, then save it to your computer in a directory of your choice.				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — CIP-006-1 — Progress Energy Request for Interpretation (Project 2008-10)

Summary Consideration: There are five themes that emerged from the industry comments:

1) Wiring does not rely upon or utilize a routable protocol and thus cannot be a cyber asset any more than a power cable is. The NERC definition of cyber asset does not include the language "including the wiring that comprises the physical media supporting the network."

Response: The interpretation response team has reviewed its response and considers the wiring to be a component of the communication network, which is a cyber asset, as defined in the NERC Glossary. As such, the network wiring needs to be protected.

2) This is far too important to resolve via an interpretation. This needs to be addressed in the revisions to the CIP standards and subject to the full stakeholder process.

Response: We agree that this is an important issue, and it will be considered as part of the standards' revision in the Cyber Security Order 706 (CSO706) project (Project 2008-06). However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this request for interpretation (RFI) from Progress Energy.

3) The interpretation exceeds the process rules by changing the requirements of standard, adds concepts not consistent with other NERC guidance, speculates on the intent of the standard, and adds confusion and ambiguity with respect to compliance. It also opens the door for other non-physical "alternatives" to compliance with the requirements of CIP-006.

Response: While the drafting team disagrees it altered any requirements to the standard via the interpretation, the team acknowledges a lack of clarity regarding alternative measures. In drafting the revised interpretation, the team interprets the phrase "alternative measures" to include use of combined/complementary physical and logical approaches to achieve the same or better protection for Electronic Security Perimeter (ESP) wiring that is external to the Physical Security Perimeter (PSP).

4) The wire is not within the ESP; therefore it does not need to be protected. The wire is nothing more than a communication link specifically excluded by CIP-005, R1.3.

Response: The request clearly asked about wiring within an ESP.

5) The cost (dollars, time) to protect wiring in a campus setting far exceeds the benefit derived by doing so. The challenges of having to comply with all of the CIP-006 requirements are an impossible and unreasonable task. The decision to protect wiring should be based upon a proper risk determination process.

Response: The interpretation response team attempted to offer alternative methods for compliance without undue financial burden in the initial interpretation response. In drafting the revised interpretation, the team interprets the phrase "alternative measures" to include use of combined/complementary physical and logical approaches to achieve the same or better protection.

Entity	Segment	Vote	Comment
Allegheny Power	1	Negative	Allegheny Energy is concerned with the SAR drafting team interpretation that wiring within an ESP be considered a Cyber Asset or Critical Cyber Asset. Allegheny Energy agrees that the wiring (and information

Entity	Segment	Vote	Comment
			transmitted by such wiring) within an ESP needs to be protected; however, Allegheny Energy does not agree that the wiring needs to be classified and protected as a defined cyber asset. NERC defines cyber assets as programmable electronic devices and communication networks including hardware, software, and data and does not include the language “including the wiring that comprises the physical media supporting the network”. Allegheny Energy believes the best method to determine protection measures for the wiring (and information transmitted by such wiring) is to create a holistic approach to communication network and data communication link protection through the Standards process that specifically addresses these issues. This new Standard could address communication network and data communication link security issues, including copper cabling, fiber optic cabling, and wireless implementations. By the interpretation stating that network wiring is a cyber asset or potentially a critical cyber asset in an effort to physically secure the wiring, this statement would additionally impose all of the requirements of the CIP standard that are applicable to cyber assets and in essence make entities non-compliant since many requirements cannot be accomplished for wiring.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. For ESP wiring that is external to the PSP: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or monitoring to detect unauthorized access or physical tampering. The RFI response drafting team agrees that this is an important issue and it will be considered as part of the standards’ revision in the Cyber Security Order 706 (CSO706) project.			
Ameren Services Company	1	Negative	We do not agree with this interpretation. We feel that the language in the first sentence of the response, "including the wiring that comprises the physical media supporting the network," could be viewed to include aspects that are not covered in the CIP 002 - 009. Broad interpretation of the response would significantly impact the compliance burden. In addition, CIP 006 R1.1 states: "Where a completely enclosed (six-wall) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." This interpretation does not make it clear whether or not that part of the CIP-006 requirement 006 is still valid, and seems to supersede the CIP standard in this regard.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within			

Entity	Segment	Vote	Comment
an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
American Electric Power	1	Negative	Physical protection (given the relatively controlled locations of some of the data paths in question) should be determined by a risk-based assessment. This would be particularly focused on the likelihood of intrusion given the overall physical environment and other factors (cables buried, guard forces, monitoring cameras, etc.), some of which may qualify as acceptable alternative measures. We believe that this topic should be addressed during the formal development of the next iteration of CIP standards to clarify requirements and include risk factors and a rational, realistic approach. For example, securing a facility housing coal handling systems makes complete sense from a potential intrusion perspective. This is less the case with the cabling running externally from the facility to the control room, often buried and not easily or in obtrusively accessible. Because of the factor listed above, AEP is casting a negative vote for this interpretation. We would prefer that it be addressed fully during the development of the next set of NERC CIP standards.
Response: The RFI response drafting team agrees that this is an important issue and it is presently being considered as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A methodology for determining the appropriate protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Associated Electric	1	Negative	Wiring meets none of the requirements of CIP-002-R3, the wiring does not communicate itself with anything, it is merely a communications conduit or channel, therefore the standard does not apply to it anymore than it

Entity	Segment	Vote	Comment
Cooperative, Inc.			would apply to the ac power wiring. While it is appropriate to protect access to all wiring inside the ESP, I do not believe that the intent of the standard is to consider wiring a CCA and subject it to all of the CIP requirements, many of which can not even be implemented or do not apply. These points were presented very well (and I am in complete agreement with) in the document by Mr. Tim Conway of NiSource, “Wiring as a CCA”.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Brazos Electric Power Cooperative, Inc.	1	Negative	Further clarity should be added to the last sentence to address the interpretation request as follows: Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures as it extends from the ESP up to the Physical Security Perimeter. Then there is the question about what is defined as "tampering".
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering. The RFI response drafting team views tampering to include, but is not limited to, unauthorized access, disruption, or alteration.			
Consolidated Edison Co. of New York	1	Negative	The interpretation is not clear and may modify the intention of the Standard, in our opinion, and needs more work. The existing Standard requirement clearly states, "...all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.

Entity	Segment	Vote	Comment
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
FirstEnergy Energy Delivery	1	Negative	FE thanks the SAR team for their efforts in developing an interpretation for CIP-006-1 Req. R1.1 in response to Progress Energy's request. However, we have cast a Negative vote for the following reasons and ask the team to consider our comments and suggested revision. We feel that the proposed interpretation fails to provide the industry with a clear direction related to the question posed by Progress Energy. As stated, the interpretation largely restates the definition of a Cyber Asset contained in the NERC Glossary of Terms, and a re-statement of CIP-006 R1.1. The interpretation states that "The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." However, the actual definition from the NERC Glossary states that "Cyber Assets include programmable electronic devices and communication networks including hardware, software, and data." Further, in the CIP standards development process the communications paths were deliberately excluded from the scope of the Standards, especially third party communication assets. Accordingly, we concur with the aspect of the interpretation that implies that the communications hardware devices and closets that include critical cyber assets should be secured inside the PSP, but that the physical utility-owned wiring should not be classified as Cyber Asset as the interpretation indicates. This would be consistent with the explicit exclusion of the third party communication assets embodied within the standards. We agree that the definition includes the data as a Cyber Asset, but do not agree that the definition includes the physical wiring as a Cyber Asset. Accordingly as a potential modification to the interpretation, we suggest a revision to the interpretation as follows: "The definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team asserts that physical media (wiring) is a component of a communication network within an ESP and shall be secured inside the Physical Security Perimeter. The communication assets excluded from the standards are the Cyber Assets associated with communication networks and data communication links between			

Entity	Segment	Vote	Comment
discrete ESPs. There is no explicit reference within the standards to third-party communications. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Hydro One Networks, Inc.	1	Negative	Hydro One Networks Inc. is casting a Negative vote with the following comment: The interpretation is not clear and may modify the intention of the Standard. It needs more work. The existing Standard requirement clearly states, "...all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter," which must be protected. While the wires connecting two ESPs need to be protected it should not make one PSP of both. Appropriate conduit or similar protection as appropriate should be acceptable.
Response: The equipment configuration described in this comment wherein two physically separate Cyber Assets that are individually classified as having its own ESP would indeed not require physical access protection for the interconnecting wiring. However, the situation as described by the requestor is different. The configuration indicated by the requestor involves physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.			
Manitoba Hydro	1	Negative	Manitoba Hydro agrees with the part of the interpretation provided by the SAR drafting team that protection of the data transmitted over wires within an Electronic Security Perimeter as the intent of the requirement. This provides more flexibility to meet the standard by allowing not only physical protection of the wire, but also alternative protective measures for the data such as encryption. Responsible Entities should take reasonable measures to protect the data within an Electronic Security Perimeter. However, Manitoba Hydro does not agree with the part of the interpretation provided by the SAR drafting team that “the definition of a Cyber Asset includes both the data and communication networks, including the wiring that comprises the physical media supporting the network.” It should be made clear that the wiring within an Electronic Security Perimeter is considered as part of the Cyber Asset (programmable device or communication network) and that wiring is not itself a Cyber Asset. Since the term communication network is not a NERC defined or clearly understood industry term, the interpretation should not use communication network (or network) as part of any clarifying statement.
Response: The RFI response drafting team agrees and submits a revised RFI response. The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. However, the			

Entity	Segment	Vote	Comment
drafting team disagrees with removal of the term communication network in the RFI response as it is already referenced in the NERC Glossary definition of a Critical Cyber Asset.			
National Grid	1	Negative	The interpretation is not clear and may modify the intention of the Standard. The existing Standard requirement clearly states, "...all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures for ESP wiring that is external to the PSP may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
New Brunswick Power Transmission Corporation	1	Negative	The interpretation is not clear and may modify the intention of the Standard, in our opinion, and needs more work. The existing Standard requirement clearly states, "…all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Orange and Rockland Utilities, Inc.	1	Negative	Orange and Rockland cannot support CIP-006 R1.1 and requests further clarification of "alternative protection measures" encompassing the wiring that comprises the "physical media" supporting the network.
Response: The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures for ESP wiring that is external to the PSP may include, but are not			

Entity	Segment	Vote	Comment
limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Pacific Gas and Electric Company	1	Negative	As written the interpretation is too broad. The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within the pertinent parts of a given facility or campus.
Response: The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border: alternative physical control measures for ESP wiring that is external to the PSP may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
PacifiCorp	1	Negative	"The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus." "If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances."
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets "alternative measures" for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: "Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering. The drafting team believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected not to include such language.			
Potomac Electric	1	Negative	Pepco is a subsidiary of PHI. PHI feels that the interpretation is not clear and the response itself is subject to interpretation. This lack of clarity is the basis for PHI's rejection. PHI also believes that communication systems

Entity	Segment	Vote	Comment
Power Co.			should be protected. The Answer to Question 11 of the FAQ associated with these standards states that communication systems are not covered by these standards.

Response:

The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The asset owner is encouraged to reconsider the design of a communication network that extends the ESP across third-party communications systems and networks.

The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection.

CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.

Question 11 of the FAQ for standard CIP-002-1 – Cyber Security – Critical Cyber Assets (reproduced below) refers to Section A 4.2.2 regarding the exclusion of Cyber Assets associated with communication networks and data communication links between discrete ESPs. Communications within the ESP are covered by these standards.

CIP-006-1 The asset owner is encouraged to reconsider the design of a communication network that extends the ESP across third-party communications systems and networks.

11. FAQ - Question: *Do communication-related Cyber Assets for Critical Cyber Assets require protection under the Cyber Security Standards?*

Answer: Communications is not covered under this standard because communications are often leased by the Responsible Entities and the technologies for existing Cyber Assets do not always support encryption or other possible security alternatives. Asset owners are encouraged, whenever possible, to provide communications or communication systems with the same protection as their associated Critical Cyber Asset.

PP&L, Inc.	1	Negative	The definition of a Cyber Asset includes both the data and the routable protocol-based communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures. Alternative protection measures could include 24 x7 monitoring, alerting, and logging of attempts at or actual compromise of the network. Supporting information: Based on CIP-002, R3, the definition introduced by the Interpretation should be limited to the "routable protocol-based" communication networks associated with Cyber Assets.

Response:

The RFI response team agrees with the comment that the objective is to protect the data. To do so requires measures to prevent tampering of Cyber Assets. However, the RFI response team disagrees with the last point. The drafting team asserts that the requirement R1.1 does not limit application of alternative measures only to “routable protocol-based communication networks” and therefore doing so is unjustified.

Entity	Segment	Vote	Comment
Puget Sound Energy, Inc.	1	Negative	Definition of Cyber Asset: We do not believe the existing definition of "Cyber Asset" should include wiring. From the most recent (February 12, 2008) NERC "Glossary of Terms Used in Reliability Standards": "Cyber Assets - Programmable electronic devices and communication networks including hardware, software, and data." Wires are not programmable, are not software, and are not data. While they are physical media, it is highly questionable if they could be considered hardware as our understanding is that hardware devices are what software runs on. If we were to extend the definition to include a wire strictly because it carries data, at what point do we consider a telephone pole a Cyber Asset because it carries wires which carry data? If the definition does include wiring, how then do wireless communications media fit into the definition in the context of physical protection of Cyber Assets? Wireless is neither hardware, software, or data and, with regards to this interpretation, physical protection of airborne electrons is not practical/possible with today's technology. Alternative Protective Measures: As most facilities which house Critical Cyber Assets were constructed prior to the CIP standard adoption by FERC, many such facilities have a common wiring infrastructure for both Critical Cyber Assets and assets that are not in scope for CIP compliance. We believe it is unreasonable to require every wire be traced and extracted from common conduit, cable bundles, or other common pathway for the purposes of re-enclosing them in a CIP-specific conduit or other “six-wall” perimeter. The very act of performing this work will introduce an increased reliability risk. If wiring is to be included in the definition of Cyber Asset, we feel that a “completely enclosed (“six-wall”) border” cannot be established for most wiring infrastructures given the above. Therefore, the "alternative measures to control physical access to the Critical Cyber Assets" phrase from CIP-006 R1.1 must be used. The definition for Critical Cyber Assets require that a Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or, the Cyber Asset uses a routable protocol within a control center; or, the Cyber Asset is dial-up accessible, and wiring has no such attributes. Given that CIP-006 R1.1 talks about both Cyber Assets and Critical Cyber Assets, can the interpretation team comment on the above? We would also like clarification on whether "alternative protective measures" includes situations that only deploy purely logical controls of data transiting the wire. As the interpretation team has stated, “The intent is to protect the data transmitted over the network within the ESP”, would an ESP that spans an entity’s entire infrastructure and only employs logical “alternative protective measures”, be an acceptable response to this interpretation? Summary: We commend the interpretation team for wanting to address data in motion, but the appropriate venue to address this issue is NERC Project 2008-06 as CIP-006 R1.1 prescribes requirements for physical protection of Cyber Assets (or just Critical Cyber Assets when a “six-wall” perimeter cannot be established) within an ESP. Additionally, based on our assessment of the term Cyber Asset, we believe requirements to protect communications media are beyond the scope of the existing CIPs. Outstanding RFI How does the Project 2008-10 interpretation for Progress Energy relate to the previous interpretation request (below) from October 10, 2007 by Puget Sound Energy? --- 1) We are requesting an interpretation of the term “externally connected” as used in 005.R1.1. Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s) We request an interpretation which allows encrypted connections over frame relay within a single ESP. Note in the diagram above the routers are not considered “access points” to the ESP, but rather are contained within it. 2) We are requesting clarification of CIP-006-1 R1.1: Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely

Entity	Segment	Vote	Comment
			enclosed ("six wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets. The standard does not explicitly require a given ESP to be fully contained by a single PSP. We request a clarifying interpretation which allows an ESP to span multiple PSPs provided that communications within the ESP are protected sufficiently to prevent unauthorized access. Commentary: With the use of encrypted tunnels and physical protection of the tunnel endpoints, we believe that secure, CIPS compliant ESPs can be designed which span multiple PSPs. It should be noted that 005.R1.3 defines communication links between ESPs as an "access point", which in turn requires port/protocol restrictions at the access point (005.R2.2). However, OSI layer 3 controls won't solve what is fundamentally an OSI layer 2 concern. Specifically, port and protocol restrictions at the endpoints of a frame relay connection will not adequately mitigate the risk of exposure to packets being manipulated at OSI Layer 2. Hence, our desire to use encrypted tunnels to assure packet integrity and source authenticity thereby addressing the layer 2 concerns. Thank you for the opportunity to comment.
Response: The RFI response team agrees with the comment that the main objective is to protect the data. To do so requires measures to prevent tampering of Cyber Assets. In regard to wiring, the RFI response drafting team asserts that the definition of Cyber Asset in the NERC Glossary indeed includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets "alternative measures" to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. With respect to the commentary about a single ESP spanning multiple PSPs, the specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside the ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 applies. The drafting team is not familiar with the October 10, 2007 RFI by Puget Sound Energy.			
Salt River Project	1	Negative	In cases where the building hosting the Critical Asset is under control of the Registered Entity, the building itself should serve as the six sided physical container. The possibility of an employee, contractor or guest pulling up a floor panel or ceiling tile, finding the right cable or fiber, and then having a way to tap or monitor the line is not a credible threat.
Response:			

Entity	Segment	Vote	Comment
The building hosting the Critical Asset, when under the control of the Responsible Entity, is a qualified Physical Security Perimeter only when access is controlled per CIP-006-1 and all personnel with unescorted access have met the applicable requirements of the CIP standards, including completion of personnel risk assessments and training. If the entire building is not a qualified PSP, then alternative measures must be applied to protect wiring not enclosed within the qualified PSP(s) within the building.			
Seattle City Light	1	Negative	The reasoning for this vote is as follows: As noted in the Progress Energy submittal to NERC, they have cited the requirements for Critical Cyber Assets (CCAs) to be contained within the Electronic Security Perimeter (ESP) and for the ESP to be contained within the Physical Security Perimeter. However, a scenario can easily develop whereby CCA's are connected via cable/wiring and the affected wiring runs outside of the ESP and sometimes outside of the Physical Security Perimeter. In some instances the wiring could be underground, in cable trays, and even via poles and towers. Therefore, the key issue to recognize is that the cables/wires may be in circumstances whereby complete encapsulation (i.e., to achieve the "6-sided wall" mandate) would be extraordinarily expensive, extremely difficult, and in many cases not add any added physical protection due to the location of the wire/cable and distance away from unauthorized tampering. Also, if the cables are still within the physical security perimeter but outside the ESP, then added protection is not necessarily value added from a security standpoint because physical access is still afforded but not accepted in the interpretation. Our recommendation is that the interpretation take into account the security buffer between the Electronic Security Boundary and the Physical Security Boundary for cables/wires. Secondly, it is also recommended that protection of the data is paramount and that some logical controls should be taken into account for data protection even though the cable may be external to the ESP. Thirdly, encapsulating cable with conduit, cages or other "6-sided wall" protective measures may not be reasonable for the security value add and that the interpretation should take into account the physical location of the wires/cables that prevent an unauthorized party from tampering with the physical layer of the equipment.

Response:

The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.

The scenario described in this comment wherein two physically separate Cyber Assets that are individually classified as each having its own ESP would indeed not require physical access protection for the connective wiring.

The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. These measures can account for data protection.

The recommendation to address data in motion is currently included in the work of the CSO706 Project.

Entity	Segment	Vote	Comment
Sierra Pacific Power Co.	1	Negative	This interpretation seems to expand the applicability of the CIP Requirements outside the bounds of the Critical Assets.
Response: The RFI response drafting team does not expand the applicability of the CIP requirements but states the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset.			
Southern California Edison Co.	1	Negative	Southern California Edison Company (SCE) SCE appreciates the opportunity to provide comments on the NERC Standards Development team's proposed interpretation for CIP-006-1's Requirement 1.1 ("Proposed Interpretation"). SCE cast a negative vote on the Proposed Interpretation because it causes additional confusion and could result in unreasonable and impractical consequences that would not improve the security of the Cyber Assets or the Electronic Security Perimeter. SCE believes issues identified by Progress Energy should be addressed during the review of CIP-006 scheduled to take place in 2009. Supporting reasons for this position are provided below. The proposed interpretation states that "Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." SCE shares a concern raised by WECC in their position paper that if the physical media used to transport critical data is considered a Critical Cyber Asset, then it would require all of the requisite physical protections specified in the existing CIP standards. SCE feels physical media supporting the network cannot be subject to the physical protections specified in CIP standards. For example, if a network cable runs from a Critical Cyber Asset situated within an identified Physical Security Perimeter to a point or through any area that is outside the identified Physical Security Perimeter, it is not clear that taking measures to protect the cable from tampering, and potentially having to monitor access to the cable, would be an appropriate way to secure the network. Access to SCE's communications network, and the data which streams across it, is strictly controlled by an Electronic Security Perimeter which personnel and equipment/ application(s) are given narrow access rites dependent on their usage requirements. The allowance of "alternative protective measures" for physical media supporting the network is also not clearly defined, and could even be interpreted to allow for logical protections without physical protection of Cyber Assets. This clearly would not be an appropriate outcome as pointed out in WECC's position paper as well. The uncertainty created by the interpretation's reference to alternative protective measures is another reason SCE voted against the interpretation. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances. In closing, it is SCE's opinion that the Proposed Interpretation and the issues brought-up in relation to the actual definition of Cyber Asset be fully addressed and incorporated into the revised CIP-006 standard. Pursuant to NERC's Reliability Standards Development Plan an effort to revise the CIP standards will be initiated in 2009.
Response: The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that			

Entity	Segment	Vote	Comment
is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, the request from Progress Energy must be addressed in the formal Interpretation process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The drafting team recognizes there are instances that pose technical and/or costly challenges to protection of Cyber Assets and clarifies that the current requirement includes the use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. To the commenter's point regarding more prescriptive and specific language, the drafting team believes that it could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Southern Company Services, Inc.	1	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. - The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The phrase "alternative measures" in the Requirement R1.1 of CIP-006-2 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
Southwest Transmission Cooperative, Inc.	1	Negative	"The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus." "If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances."
Response:			

Entity	Segment	Vote	Comment
The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team believes alternative measures is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible.			
Tampa Electric Co.	1	Negative	Tampa Electric Company’s Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry’s attention and attempting to clarify this issue. Tampa Electric Company has several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach may be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security “ such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: ? These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. ? The primary DCS vendors in our environment have stated to us that they do not offer or support an approved mechanism for firewalling within the DCS network or encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. ? The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, Tampa Electric recommends that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations . We believe that the Standard Authorization Request should be modified to address concerns and issues related to: ? Unauthorized access to the ESP through access to physical cabling. ? Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. ? Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.

Entity	Segment	Vote	Comment
Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets “alternative measures” to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Tennessee Valley Authority	1	Negative	While we agree that physical and electronic perimeters must be the same or the data must protected as it traverses physical perimeters, TVA doesn't think that the interpretation provides sufficient detail to guide compliance.
Response: The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. The RFI response drafting team is limited in its ability to provide more explicit guidance and believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Tucson Electric Power Co.	1	Negative	TEP supports the following provided by WECC: "The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus." "If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances."
Response: The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to			

Entity	Segment	Vote	Comment
avoid such language.			
Westar Energy	1	Negative	Disagree with the concept that wire is a Cyber Asset.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset.			
Western Area Power Administration	1	Negative	The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to "wires within a given facility or campus" and therefore doing so is unjustified. The drafting team has clarified what it interprets "alternative measures" to mean in the revised response and believes the phrase "alternative measures" is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Xcel Energy, Inc.	1	Negative	While Xcel Energy generally supports what we understand to be the intent of the interpretation, we feel it is not clear and could create further ambiguity. An interpretation should be clear and not create further room for interpretation. As explained to us by a member of the Cyber Security Order 706 SAR Drafting Team, the interpretation is designed to address the situation where there are potentially two separate physical security perimeters (PSP) with assets that are part of the same ESP -- such as two separate rooms, a data center and an operations center, that both have critical cyber assets and individual physical security perimeters. You could still have one ESP for the single building -- however, since the wiring connecting the assets in each of these rooms leaves the physical security perimeters, you need to protect the wiring with a physical boundary (conduit), or encrypt the data. We feel strongly that this interpretation, as written, could be implemented and/or enforced inconsistent with what the drafting team intended, and recommend a new draft of the interpretation, including a diagram, be developed. Also, since this interpretation will likely have a substantial impact on

Entity	Segment	Vote	Comment
			entities, an implementation plan should be considered.
Response: The RFI response drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope. The team understands the desire for more specificity and prescription such as in a diagram but believes that could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
British Columbia Transmission Corporation	2	Negative	The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of “alternative protective measures” is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: The RFI response team asserts that requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
California ISO	2	Negative	The interpretation adds requirements that are not already part of the standard. CIP-006-1 describes the requirements for physical access controls. An interpretation of a standard should not be confused with “what should have been done”. The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including explicit reference to data in transit over communications links between discrete perimeters, the interpretation moves into an area which the standard intentionally does not address. Conflicts: the interpretation crosses multiple standards CIP-006-1, R1.1 "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." CIP-005-1, R1.3: "Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s)."

Entity	Segment	Vote	Comment
			Glossary: "Cyber Assets: Programmable electronic devices and communication networks including hardware, software, and data." The reference in CIP-005, R1.3 describes "communication links"; in reality, those links are the "wiring" that the interpretation request is describing; thus, they are not within the Electronic Security Perimeter and do not need to be within a Physical Security perimeter.
Response: The RFI response drafting team recognizes that while data in transit is fundamentally the asset to be protected, it agrees that the CSO706 Project is where it should be addressed. Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
Independent Electricity System Operator	2	Negative	Although directionally the IESO is in favour of the intent of the interpretation, we believe the current interpretation wording may effectively modify the intention of the standard, which is inconsistent with NERC standard development protocol, and hence the interpretation needs more work. CIP-006-1, R1.1 states: "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures TO CONTROL PHYSICAL ACCESS(emphasis added) to the Critical Cyber Assets." the interpretation states: The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring OR ALTERNATIVE PROTECTIVE MEASURES(emphasis added). Whereas the standard clearly requires physical access control, the interpretation effectively relaxes this requirement with the words either through physical protection of the wiring or alternate protective measures where the resultant implication is that the alternate protective measures are non-physical, hence a relaxation of the standard. Although we believe the standard should be revised to allow alternative protective measures, that is not the issue being balloted.
Response: The RFI response drafting team respectfully disagrees that the scope of alternative measures does not include logical approaches. The drafting team concurs that the intent is to protect the data that travels over the wiring and asserts that either physical or logical measures are capable of achieving the desired objective.			
ISO New England, Inc.	2	Negative	There are three significant issues with this Interpretation which resulted in a negative vote: (1) the interpretation adds requirements that are not already part of the Standard, the Standard intentionally did not originally address data in transit over communication links; (2)the interpretation creates conflicts between CIP-006 R1.1 and CIP-005, R1.3, which clearly states that communication links connecting discrete ESPs shall not be considered part of the ESP; and (3) we believe that the current Standard is clear enough and this interpretation simply creates more confusion in the industry, we have not had any problems in understanding or implementing

Entity	Segment	Vote	Comment
			the Requirements in this Standard.
Response: (1) The notion of data in transit, while at the core of the protection purpose, is more appropriately addressed in the ongoing CSO706 Project. This interpretation does not add a requirement to protect communication links, or the data transiting thereon, that are outside of the ESP. (2) Although the drafting team is limited to respond to this request from Progress Energy, to the point about "communication links" cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP. (3) The drafting team is compelled by process to respond to this RFI from Progress Energy.			
Midwest ISO, Inc.	2	Negative	The FAQ developed along with the original CIP standards specifically state that the standards are not intended to address the wires between facilities. While we agree that the suggested interpretation is a good idea for a future improvement to the standard, the interpretation process is intended to clarify what the standard says as originally drafted, not what we would like the standard to say.
Response: The FAQ is a guidance document and is not mandatory and enforceable as NERC standards are. However, question #11 (reproduced below) refers to assets that are not owned by the Responsible Entity, such as third party telecommunications company equipment. This interpretation does not add a requirement to protect communication links, or the data transiting thereon, that are outside of the ESP. In this instance, the wiring referenced by Progress Energy is clearly within a single ESP. **11. FAQ - Question:** *Do communication-related Cyber Assets for Critical Cyber Assets require protection under the Cyber Security Standards?* **Answer:** Communications is not covered under this standard because communications are often leased by the Responsible Entities and the technologies for existing Cyber Assets do not always support encryption or other possible security alternatives. Asset owners are encouraged, whenever possible, to provide communications or communication systems with the same protection as their associated Critical Cyber Asset.			
PJM Interconnection, L.L.C.	2	Negative	PJM has the following concerns: Procedural: the interpretation adds requirements that are not already part of the standard. CIP-006-1 describes the requirements for physical access controls. An interpretation of a standard should not be confused with "what should have been done". The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including an explicit reference to data in transit over communications links between discrete perimeters, the interpretation moves into an area which the standard intentionally does not address. Conflicts: the interpretation crosses multiple standards CIP-006-1, R1.1 "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." CIP-005-1, R1.3: "Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s)." Glossary: "Cyber Assets: Programmable

Entity	Segment	Vote	Comment
			electronic devices and communication networks including hardware, software, and data." The reference in CIP-005, R1.3 describes "communication links"; in reality, those links are the "wiring" that the interpretation request is describing; thus, they are not within the Electronic Security Perimeter and do not need to be within a Physical Security perimeter. Necessity: the definitions and descriptions contained within the published standard seem clear; the issue has posed no significant problems for SWG member organizations to understand or implement.
Response: The RFI response drafting team recognizes that while data in transit is fundamentally the asset to be protected, it agrees that the CSO706 Project is where it should be addressed. This interpretation does not add a requirement to protect communication links, or the data transiting thereon, that are outside of the ESP. The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
Alabama Power Company	3	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. - The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The phrase “alternative measures” in the Requirement R1.1 of CIP-006-2 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
American Electric Power	3	Negative	Although we agree that a true "systems" approach to data protection would also include the data paths, we are concerned about an element that we believe should be included in any determination of communication path physical security. Physical protection (given the relatively controlled locations of some of the data paths in question) should be determined by a risk-based assessment. This would be particularly focused on the likelihood of intrusion given the overall physical environment and other factors (cables buried, guard forces, monitoring cameras, etc.), some of which may qualify as acceptable alternative measures. We believe that this topic should be addressed during the formal development of the next iteration of CIP standards to clarify requirements and include risk factors and a rational, realistic approach. For example, securing a facility housing coal handling systems makes complete sense from a potential intrusion perspective. This is less the case with the cabling running externally from the facility to the control room, often buried and not easily or in obtrusively

Entity	Segment	Vote	Comment
			accessible. Because of the factor listed above, AEP is casting a negative vote for this interpretation. We would prefer that it be addressed fully during the development of the next set of NERC CIP standards.
Response: The RFI response drafting team agrees that this is an important issue and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Consolidated Edison Co. of New York	3	Negative	The interpretation is not clear, may modify the intention of the Standard, and needs more work. The existing Standard requirement clearly states, "..all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Consumers Energy	3	Negative	Consumers Energy’s understanding of the requirements of CIPS-005-1 and CIPS-006-1 as they were being developed and as they exist today allowed for discrete non-contiguous physical security perimeters to protect cyber assets contained within a single electronic security perimeter, presumably by excluding the communication network and data passing over the communication network as being defined as Cyber Assets requiring physical protection. We believe that this view is consistent with good utility practice utilized at a number of North America’s control centers and generating plants. In extending the definition of Cyber Asset to include data and the communication network, the Interpretation clearly goes beyond the scope intended by the original drafters of the Standards. CIP-002-1 R3, Critical Cyber Asset Identification, refers to several examples of possible Critical Cyber Assets, all of which can be considered computer systems or devices possessing a central processing unit. Seven of the nine requirements in CIP-007-1 refer to Cyber Assets and clearly are intended to apply to computer systems, and none of the nine requirements specifically address network cables or data. Had the original intent of the standards been to include the communication networks within an electronic security perimeter as Cyber Assets requiring physical protection we would have expected the standard to address appropriate protection where six-wall physical protection (complete with access control

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			and monitoring) is not necessary (such as with buried portions of the network) or practical (such as within raceways or conduit). Additionally, the time required to re-wire such networks so as to provide six-wall physical protection is significantly longer than the time required to provide six-wall physical protection to the access points to Cyber Assets within the Electronic Security Perimeter. Further, had the original intent of the standards been to include data that passes over the communication network, the standard should have discussed the issues associated with transporting, storing and restoring back-up tapes and other removable media so as to protect cyber assets in the event the back-up data is re-introduced to the electronic security perimeter. We suggest the actual intent of the CIP Standards is to define as a Cyber Asset only those devices with a central processing unit. These are the devices susceptible to remote attack and compromise. We believe the primary intent of the present version of the CIP Standards is to protect against remote compromise of those assets. The apparent intent of the Interpretation, to require all network cabling be protected by a six-wall boundary, goes beyond the intent of the CIP Standards as they were developed and implemented. CIP-006-1 R1.1 states "ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter." This does not require a piece of hardware without a CPU, such as a network cable, to reside within a six-wall boundary. Consumers Energy argues that protecting communication network cabling residing in an area entirely within the reasonable and prudent control of the Responsible Entity is beyond the scope of the present CIP Standards. Had the intent of the requirement been to include all communication network and data as Cyber Assets requiring physical protection, the wording should have stated such. If the apparent intent of the Interpretation, to require network cabling to be contained within a six-wall boundary, is accepted, there will be no distinction between "in-house" cabling and connections carried through public networks. This ignores the different threat exposure of the two types of communication circuits. This Interpretation will divert money and other resources from mitigating higher threat exposures, such as man-in-the-middle attacks on unencrypted external communications circuits, to this lower threat exposure. We propose the following wording to replace the existing interpretation: Response: The Physical Security Perimeter is required to protect the access points to Critical Cyber Assets within the Electronic Security Perimeter. For dedicated communication networks within a discrete Electronic Security Perimeter under the normal reasonable and prudent control of the Responsible Entity, all elements of such network do not require to be contained within the Physical Security Perimeter so long as all access points to the Critical Cyber Assets within the Electronic Security Perimeter are also within a Physical Security Perimeter. CIP-005-1 R1.1 refers to any externally connected communication end point (for example, dial-up modems) as specifically identified as an access point to the Electronic Security Perimeter. The use of "externally connected" in this context refers to communication facilities outside the control of the Responsible Entity. Examples of such connections would include dial-up or leased telephone or data circuits, commercial packet-switched networks, wireless networks, or the Internet. Examples of connections not considered to be "external" would include local area networks between floors in a building or between buildings in a campus environment.
Response: The RFI response drafting team believes the commenter's presumption that protection is not required for wiring between "discrete non-contiguous physical security perimeters" is not justified. The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a			

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single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 justifiably applies. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP. The drafting team believes that the other concerns raised by the commenter, including transfer of backup tapes and other removable media, is best addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project.			
Cowlitz County PUD	3	Negative	Cowlitz County PUD No.1 (District) finds the interpretation does not clarify the intent of the Standard. Extension of the "6-wall" physical security perimeter with conduit would require an accounting for all access points (condulets or conduit bodies) and appropriate access monitoring. Simple use of conduit does not offer the best protection of data as it can be easily compromised. The verbiage "or alternative protective measures" needs clarification - or alternative physical and/or logical protective measures - to protect the original intent of the Standard. The District's position is that logical protective measures (such as loss of continuity alarms) will in many cases better protect data from malicious tampering than physical protective measures.
Response: The RFI response drafting team clarifies CIP-006 R1.1 which states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Duke Energy Carolina	3	Negative	Thank you for the opportunity to vote on this interpretation. We think that the interpretation is unclear. A new NERC Cyber Security drafting team is in the process of being assembled, and Duke Energy believes that this issue is best addressed in a comprehensive manner by the new Cyber Security drafting team. The manner of protecting data from tampering when it is transmitted over networks should be clearly defined in the new Cyber Security Standard, and any newly prescribed protection methods must be properly related to other requirements in the standards where that is appropriate.
Response: The RFI response drafting team agrees that this is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			

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FirstEnergy Solutions	3	Negative	FE thanks the SAR team for their efforts in developing an interpretation for CIP-006-1 Req. R1.1 in response to Progress Energy's request. However, we have cast a Negative vote for the following reasons and ask the team to consider our comments and suggested revision. We feel that the proposed interpretation fails to provide the industry with a clear direction related to the question posed by Progress Energy. As stated, the interpretation largely restates the definition of a Cyber Asset contained in the NERC Glossary of Terms, and a re-statement of CIP-006 R1.1. The interpretation states that "The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." However, the actual definition from the NERC Glossary states that ""Cyber Assets include programmable electronic devices and communication networks including hardware, software, and data." Further, in the CIP standards development process the communications paths were deliberately excluded from the scope of the Standards, especially third party communication assets. Accordingly, we concur with the aspect of the interpretation that implies that the communications hardware devices and closets that include critical cyber assets should be secured inside the PSP, but that the physical utility-owned wiring should not be classified as Cyber Asset as the interpretation indicates. This would be consistent with the explicit exclusion of the third party communication assets embodied within the standards. We agree that the definition includes the data as a Cyber Asset, but do not agree that the definition includes the physical wiring as a Cyber Asset. Accordingly as a potential modification to the interpretation, we suggest a revision to the interpretation as follows: "The definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: The RFI response drafting team asserts that physical media (wiring) is a component of a communication network within an ESP and shall be secured inside the Physical Security Perimeter. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Georgia Power Company	3	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. -

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			The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The RFI response drafting team has clarified that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The phrase “alternative measures” in the Requirement R1.1 of CIP-006-2 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
Gulf Power Company	3	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. - The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The RFI response drafting team has clarified that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The phrase “alternative measures” in the Requirement R1.1 of CIP-006-2 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
Hydro One Networks, Inc.	3	Negative	Hydro One Networks Inc. is casting a Negative vote with the following comment: The interpretation is not clear and may modify the intention of the Standard. It needs more work. The existing Standard requirement clearly states, "..all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter," which must be protected. While the wires connecting two ESPs need to be protected it should not make one PSP of both. Appropriate conduit or similar protection as appropriate should be acceptable.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the			

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connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 justifiably applies. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. Appropriate conduit, as suggested by the commenter, is an acceptable physical protection.			
Lincoln Electric System	3	Affirmative	Any wiring within the electronic security perimeter must be protected by a six-wall physical security perimeter. Wiring external to the electronic security perimeter constitutes a "communications link", and therefore does not need to be protected by the physical security perimeter. It appears that some confusion on this issue stems from the fact that Progress Energy's original question isn't even possible - it pertains to wiring within the electronic security perimeter, but outside the physical security perimeter. According to Requirement 1.1, the electronic security perimeter must be a subset of the physical security perimeter. Therefore, any wiring within the electronic security perimeter must also fall within the physical security perimeter by default.
Response: The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside the ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 applies.			
Madison Gas and Electric Co.	3	Negative	We disagree with the interpretation because it adds language that needs further interpretation and does not address our confusion in the Standard regarding when data traveling over a network needs to be protected and when it does not. The interpretation implies the measures referenced in CIP006, R1.1, focus on preventing physical access that would allow data to be tampered with in transit. Can we assume the focus is not on preventing physical access that allows data to be gathered/inspected, but rather to prevent tampering with the data? If so, would using optical fibers carrying data communication between two physical security perimeters be a sufficient physical control, assuming fiber provides a higher level of security to protect the data from tampering. Do optical fibers contained within a continuous, fully-jacketed cable, the only end points of which are contained within separate six-sided physical security perimeters, meet the requirements of the Standard under this interpretation? If not, what constitutes the physical security perimeter and what constitutes a physical access point? Please provide guidance, including examples, on the "alternative protective measures" that would be acceptable to meet the standard. The standards are confusing because of the explicit exemption under the Introduction section, Item 4.2.2, of each standard that excludes "Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters." We assume "communication networks" and "communication links between discrete ESP's" are two different things, since they are referenced separately in other parts of the Standard. Communication links between discrete ESP's are referenced in CIP-005, R1.3, as being outside of the ESP. This reference does not help to clarify the exemption. In addition, communication networks are not referenced in CIP-005, R1.3, or anywhere else except in the definition of Cyber Assets. To say that communication networks are exempt from the Standard implies the data traveling on those networks are also exempt. If this is incorrect, what is NERC's interpretation of the

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			explicit exemption? From a protection standpoint, if there is a difference between the wire and the data traveling across the wire, that needs to be explicitly defined. Where does the Standard state whether data traveling between ESP's does or does not have to be protected?
Response: The RFI response drafting team agrees that protection of data in motion is an important issue and is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. This request from Progress Energy must be addressed in the formal Interpretation process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team disagrees with the commenter that the exemption in R4.2.2 applies because the specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 indeed applies. In the revised response to Progress Energy, the drafting team interprets alternative measures to include approaches that are physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Manitoba Hydro	3	Negative	Manitoba Hydro agrees with the part of the interpretation provided by the SAR drafting team that protection of the data transmitted over wires within an Electronic Security Perimeter as the intent of the requirement. This provides more flexibility to meet the standard by allowing not only physical protection of the wire, but also alternative protective measures for the data such as encryption. Responsible Entities should take reasonable measures to protect the data within an Electronic Security Perimeter. However, Manitoba Hydro does not agree with the part of the interpretation provided by the SAR drafting team that "the definition of a Cyber Asset includes both the data and communication networks, including the wiring that comprises the physical media supporting the network." It should be made clear that the wiring within an Electronic Security Perimeter is considered as part of the Cyber Asset (programmable device or communication network) and that wiring is not itself a Cyber Asset. Since the term communication network is not a NERC defined or clearly understood industry term, the interpretation should not use communication network (or network) as part of any clarifying statement.
Response: The RFI response drafting team agrees and submits a revised interpretation response stating the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset.			

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However, the drafting team disagrees with removal of the term communication network in the RFI response as it already referenced in the NERC Glossary.			
MidAmerican Energy Co.	3	Negative	MidAmerican Energy believes that this interpretation expands the requirements of the standard inappropriately.
Response: The RFI response drafting team does not expand the meaning of but rather interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Mississippi Power	3	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. - The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The phrase “alternative measures” in the Requirement R1.1 of CIP-006-1 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
New York Power Authority	3	Negative	The interpretation is not clear and may modify the intention of the Standard, in our opinion, and needs more work. The existing Standard requirement clearly states, "... all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimieter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a			

Entity	Segment	Vote	Comment
completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Niagara Mohawk (National Grid Company)	3	Negative	The interpretation is not clear and may modify the intention of the Standard and therefore needs more work. The existing Standard requirement clearly states, "..all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimieter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Platte River Power Authority	3	Negative	The interpretation would be acceptable if language is added similar to what is suggested below: The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering. Where (“six-wall”) physical protection of the wiring cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to			

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physical tampering.			
Public Utility District No. 2 of Grant County	3	Affirmative	
Salt River Project	3	Negative	In cases where the building hosting the Critical Asset is under control of the Registered Entity, the building itself should serve as the six sided physical container. The possibility of an employee, contractor or guest pulling up a floor panel or ceiling tile, finding the right cable or fiber, and then having a way to tap or monitor the line is not a credible threat.
Response: The building hosting the Critical Asset, when under the control of the Responsible Entity, is a qualified Physical Security Perimeter only when access is controlled per CIP-006-1 and all personnel with unescorted access have met the applicable requirements of the CIP standards, including completion of personnel risk assessments and training. If the entire building is not a qualified PSP, then alternative measures must be applied to protect wiring not enclosed within the qualified PSP(s) within the building.			
Seattle City Light	3	Negative	The reasoning for this vote is as follows: As noted in the Progress Energy submittal to NERC, they have cited the requirements for Critical Cyber Assets (CCAs) to be contained within the Electronic Security Perimeter (ESP) and for the ESP to be contained within the Physical Security Perimeter. However, a scenario can easily develop whereby CCA's are connected via cable/wiring and the affected wiring runs outside of the ESP and sometimes outside of the Physical Security Perimeter. In some instances the wiring could be underground, in cable trays, and even via poles and towers. Therefore, the key issue to recognize is that the cables/wires may be in circumstances whereby complete encapsulation (i.e., to achieve the "6-sided wall" mandate) would be extraordinarily expensive, extremely difficult, and in many cases not add any added physical protection due to the location of the wire/cable and distance away from unauthorized tampering. Also, if the cables are still within the physical security perimeter but outside the ESP, then added protection is not necessarily value added from a security standpoint because physical access is still afforded but not accepted in the interpretation. Our recommendation is that the interpretation take into account the security buffer between the Electronic Security Boundary and the Physical Security Boundary for cables/wires. Secondly, it is also recommended that protection of the data is paramount and that some logical controls should be taken into account for data protection even though the cable may be external to the ESP. Thirdly, encapsulating cable with conduit, cages or other "6-sided wall" protective measures may not be reasonable for the security value add and that the interpretation should take into account the physical location of the wires/cables that prevent an unauthorized party from tampering with the physical layer of the equipment.
Response: The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.			

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The scenario described by the commenter wherein two physically separate Cyber Assets that are individually classified as each having its own ESP would indeed not require physical access protection for the connective wiring. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. These measures can account for data protection. The recommendation to address data in motion is currently included in the work of the CSO706 Project.			
Tampa Electric Co.	3	Negative	Tampa Electric Company’s Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry’s attention and attempting to clarify this issue. Tampa Electric Company has several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach may be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: • These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. • The primary DCS vendors in our environment do not offer or support an approved mechanism for encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. • The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, Tampa Electric recommends that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective

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			based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations . We believe that the Standard Authorization Request should be modified to address concerns and issues related to: • Unauthorized access to the ESP through access to physical cabling. • Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. • Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.
Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets "alternative measures" to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project.			
Wisconsin Public Service Corp.	3	Negative	The interpretation for CIP-006 significantly expands the scope of the standard and needs to go through through the SAR process. The inclusion of communications network wiring is a shift from previous industry understanding and is contrary to responses for Frequently Asked Questions posted on the NERC website. Standard CIP-002-1 — Cyber Security — Critical Cyber Assets 11. Question: Do communication-related Cyber Assets for Critical Cyber Assets require protection under the Cyber Security Standards? Answer: Communications is not covered under this standard because communications are often leased by the Responsible Entities and the technologies for existing Cyber Assets do not always support encryption or other possible security alternatives. Asset owners are encouraged, whenever possible, to provide communications or communication systems with the same protection as their associated Critical Cyber Asset. Standard CIP-005-1 Cyber Security — Electronic Security 2. Question: I am connected to other partners Electronic Security Perimeters through a Wide Area Network (WAN) connection. What is now included in the Electronic Security Perimeter? Is the connection to the partner included? Answer: The standard states that where discrete Electronic Security Perimeters are connected by communication lines, the communication lines are not included in the Electronic Security Perimeter. 15. Question: Is a physically isolated and dedicated network required for connections between Electronic Security Perimeters? Answer: No, physical isolation is not required, nor is a dedicated link required. The standard does not specify any requirement for communication between discrete Electronic Security Perimeters, since this is currently beyond the scope of these standards. It

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			is possible for the data between discrete perimeters to be carried over a shared infrastructure such as a shared WAN, or to be carried over dedicated links. However, the Responsible Entity must ensure that the access control devices (such as firewalls) at the access points to the Electronic Security Perimeters do not permit unauthorized access to the Electronic Security Perimeters and the Cyber Assets within them. When data is carried over a shared infrastructure, the Responsible Entity should ensure as well that the data has not been changed in transit. Logical or virtual separation of the data in a shared infrastructure can be accomplished by using existing technologies such as virtual circuits and communication tunnels. Encryption or other data integrity checking technologies can also ensure that data is not changed in transit, provided performance and latency requirements for the applications are satisfied. Standard CIP-006-1 — Cyber Security — Physical Security 20. Question: Does the standard require entities to protect telecommunications services and facilities that serve physical security system assets? Answer: CIP-002 through CIP-009 do not address telecommunications.
Response: The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. The RFI response team clarifies in a revised interpretation response that physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. Protection of communication systems that reside within an ESP is required. The Frequently Asked Questions posted on the NERC website is a guidance document and is not mandatory and enforceable as NERC standards are. However, question #11 (reproduced below) refers to assets that are not owned by the Responsible Entity such as third-party telecommunications company equipment. **11. FAQ - Question:** *Do communication-related Cyber Assets for Critical Cyber Assets require protection under the Cyber Security Standards?* **Answer:** Communications is not covered under this standard because communications are often leased by the Responsible Entities and the technologies for existing Cyber Assets do not always support encryption or other possible security alternatives. Asset owners are encouraged, whenever possible, to provide communications or communication systems with the same protection as their associated Critical Cyber Asset. In addition, the figure associated with Question 2 for CIP-005-1 (Page 12 of the FAQ) specifically addresses the commenter's concerns regarding interconnectivity of ESP's over Wide Area Networks. This interpretation does not change the exclusion of communication networks outside of an ESP from the standard. In this instance the wiring is clearly stated by Progress Energy to be within a single ESP.			
Xcel Energy, Inc.	3	Negative	While Xcel Energy generally supports what we understand to be the intent of the interpretation, we feel it is not clear and could create further ambiguity. An interpretation should be clear and not create further room for interpretation. As explained to us by a member of the Cyber Security Order 706 SAR Drafting Team, the interpretation is designed to address the situation where there are potentially two separate physical security perimeters (PSP) with assets that are part of the same ESP -- such as two separate rooms, a data center and an operations center, that both have critical cyber assets and individual physical security perimeters. You could still have one ESP for the single building -- however, since the wiring connecting the assets in each of these

Entity	Segment	Vote	Comment
			rooms leaves the physical security perimeters, you need to protect the wiring with a physical boundary (conduit), or encrypt the data. We feel strongly that this interpretation, as written, could be implemented and/or enforced inconsistent with what the drafting team intended, and recommend a new draft of the interpretation, including a diagram, be developed. Also, since this interpretation will likely have a substantial impact on entities, an implementation plan should be considered.
Response: The RFI response drafting team has clarified what it interprets "alternative measures" to mean in the revised response and believes the phrase "alternative measures" is neutral in its scope. The team understands the desire for more specificity and prescription, such as in a diagram, but believes that could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Alliant Energy Corp. Services, Inc.	4	Negative	CIP-005 - R1.3 specifically excludes the connecting cabling from the CIP standards. There can not be such conflicting statements between standards.
Response: Although the drafting team is limited to respond to this request from Progress Energy, to the point about "communication links" cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
Consumers Energy	4	Negative	Consumers Energy's understanding of the requirements of CIPS-005-1 and CIPS-006-1 as they were being developed and as they exist today allowed for discrete non-contiguous physical security perimeters to protect cyber assets contained within a single electronic security perimeter, presumably by excluding the communication network and data passing over the communication network as being defined as Cyber Assets requiring physical protection. We believe that this view is consistent with good utility practice utilized at a number of North America's control centers and generating plants. In extending the definition of Cyber Asset to include data and the communication network, the Interpretation clearly goes beyond the scope intended by the original drafters of the Standards. CIP-002-1 R3, Critical Cyber Asset Identification, refers to several examples of possible Critical Cyber Assets, all of which can be considered computer systems or devices possessing a central processing unit. Seven of the nine requirements in CIP-007-1 refer to Cyber Assets and clearly are intended to apply to computer systems, and none of the nine requirements specifically address network cables or data. Had the original intent of the standards been to include the communication networks within an electronic security perimeter as Cyber Assets requiring physical protection we would have expected the standard to address appropriate protection where six-wall physical protection (complete with access control and monitoring) is not necessary (such as with buried portions of the network) or practical (such as within raceways or conduit). Additionally, the time required to re-wire such networks so as to provide six-wall physical protection is significantly longer than the time required to provide six-wall physical protection to the access points to Cyber Assets within the Electronic Security Perimeter. Further, had the original intent of the standards been to include data that passes over the communication network, the standard should have discussed the issues associated with transporting, storing and restoring back-up tapes and other removable media so as to protect cyber assets in the event the back-up data is re-introduced to the electronic security perimeter. We

Entity	Segment	Vote	Comment
			suggest the actual intent of the CIP Standards is to define as a Cyber Asset only those devices with a central processing unit. These are the devices susceptible to remote attack and compromise. We believe the primary intent of the present version of the CIP Standards is to protect against remote compromise of those assets. The apparent intent of the Interpretation, to require all network cabling be protected by a six-wall boundary, goes beyond the intent of the CIP Standards as they were developed and implemented. CIP-006-1 R1.1 states "ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter." This does not require a piece of hardware without a CPU, such as a network cable, to reside within a six-wall boundary. Consumers Energy argues that protecting communication network cabling residing in an area entirely within the reasonable and prudent control of the Responsible Entity is beyond the scope of the present CIP Standards. Had the intent of the requirement been to include all communication network and data as Cyber Assets requiring physical protection, the wording should have stated such. If the apparent intent of the Interpretation, to require network cabling to be contained within a six-wall boundary, is accepted, there will be no distinction between "in-house" cabling and connections carried through public networks. This ignores the different threat exposure of the two types of communication circuits. This Interpretation will divert money and other resources from mitigating higher threat exposures, such as man-in-the-middle attacks on unencrypted external communications circuits, to this lower threat exposure. We propose the following wording to replace the existing interpretation: Response: The Physical Security Perimeter is required to protect the access points to Critical Cyber Assets within the Electronic Security Perimeter. For dedicated communication networks within a discrete Electronic Security Perimeter under the normal reasonable and prudent control of the Responsible Entity, all elements of such network do not require to be contained within the Physical Security Perimeter so long as all access points to the Critical Cyber Assets within the Electronic Security Perimeter are also within a Physical Security Perimeter. CIP-005-1 R1.1 refers to " any externally connected communication end point (for example, dial-up modems) " as specifically identified as an access point to the Electronic Security Perimeter. The use of "externally connected" in this context refers to communication facilities outside the control of the Responsible Entity. Examples of such connections would include dial-up or leased telephone or data circuits, commercial packet-switched networks, wireless networks, or the Internet. Examples of connections not considered to be "external" would include local area networks between floors in a building or between buildings in a campus environment.

Response:

The RFI response drafting team believes the commenter's presumption that protection is not required for wiring between "discrete non-contiguous physical security perimeters" is not justified. The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 justifiably applies.

The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected.

Although the drafting team is limited to respond to this request from Progress Energy, to the point about "communication links" cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.

Entity	Segment	Vote	Comment
The drafting team believes that the other concerns raised by the commenter, including transfer of backup tapes and other removable media, is best addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project.			
Madison Gas and Electric Co.	4	Negative	We disagree with the interpretation because it adds language that needs further interpretation and does not address our confusion in the Standard regarding when data traveling over a network needs to be protected and when it does not. The interpretation implies the measures referenced in CIP006, R1.1, focus on preventing physical access that would allow data to be tampered with in transit. Can we assume the focus is not on preventing physical access that allows data to be gathered/inspected, but rather to prevent tampering with the data? If so, would using optical fibers carrying data communication between two physical security perimeters be a sufficient physical control, assuming fiber provides a higher level of security to protect the data from tampering. Do optical fibers contained within a continuous, fully-jacketed cable, the only end points of which are contained within separate six-sided physical security perimeters, meet the requirements of the Standard under this interpretation? If not, what constitutes the physical security perimeter and what constitutes a physical access point? Please provide guidance, including examples, on the "alternative protective measures" that would be acceptable to meet the standard. The standards are confusing because of the explicit exemption under the Introduction section, Item 4.2.2, of each standard that excludes "Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters." We assume "communication networks" and "communication links between discrete ESP's" are two different things, since they are referenced separately in other parts of the Standard. Communication links between discrete ESP's are referenced in CIP-005, R1.3, as being outside of the ESP. This reference does not help to clarify the exemption. In addition, communication networks are not referenced in CIP-005, R1.3, or anywhere else except in the definition of Cyber Assets. To say that communication networks are exempt from the Standard implies the data traveling on those networks are also exempt. If this is incorrect, what is NERC's interpretation of the explicit exemption? From a protection standpoint, if there is a difference between the wire and the data traveling across the wire, that needs to be explicitly defined. Where does the Standard state whether data traveling between ESP's does or does not have to be protected?
Response: The RFI response drafting team agrees that protection of data in motion is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. This request from Progress Energy must be addressed in the formal interpretation process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team disagrees with the commenter that exemption in R4.2.2 applies because the specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-			

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006-1 indeed applies. In the revised response to Progress Energy, the drafting team interprets alternative measures to include approaches that are physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Seattle City Light	4	Negative	The reasoning for this vote is as follows: As noted in the Progress Energy submittal to NERC, they have cited the requirements for Critical Cyber Assets (CCAs) to be contained within the Electronic Security Perimeter (ESP) and for the ESP to be contained within the Physical Security Perimeter. However, a scenario can easily develop whereby CCA's are connected via cable/wiring and the affected wiring runs outside of the ESP and sometimes outside of the Physical Security Perimeter. In some instances the wiring could be underground, in cable trays, and even via poles and towers. Therefore, the key issue to recognize is that the cables/wires may be in circumstances whereby complete encapsulation (i.e., to achieve the "6-sided wall" mandate) would be extraordinarily expensive, extremely difficult, and in many cases not add any added physical protection due to the location of the wire/cable and distance away from unauthorized tampering. Also, if the cables are still within the physical security perimeter but outside the ESP, then added protection is not necessarily value added from a security standpoint because physical access is still afforded but not accepted in the interpretation. Our recommendation is that the interpretation take into account the security buffer between the Electronic Security Boundary and the Physical Security Boundary for cables/wires. Secondly, it is also recommended that protection of the data is paramount and that some logical controls should be taken into account for data protection even though the cable may be external to the ESP. Thirdly, encapsulating cable with conduit, cages or other "6-sided wall" protective measures may not be reasonable for the security value add and that the interpretation should take into account the physical location of the wires/cables that prevent an unauthorized party from tampering with the physical layer of the equipment.
Response: The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006. The scenario described by the commenter wherein two physically separate Cyber Assets that are individually classified as each having its own ESP would indeed not require physical access protection for the connective wiring. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. These measures can account for data protection. The recommendation to address data in motion is currently included in the work of the CSO706 Project.			

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Seminole Electric Cooperative, Inc.	4	Negative	Seminole endorses the comments of Tampa Electric Company as replicated below: Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry's attention and attempting to clarify this issue. We have several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach my be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: ? These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. ? The primary DCS vendors in our environment do not offer or support an approved mechanism for encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. ? The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, we recommend that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations . We believe that the Standard Authorization Request should be modified to address concerns and issues related to: ? Unauthorized access to the ESP through access to physical cabling. ? Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. ? Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.

Response:

The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets "alternative measures" to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden.

Entity	Segment	Vote	Comment
However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Wisconsin Energy Corp.	4	Negative	Interpetation is overreaching
Response: The RFI response drafting team does not expand the meaning of but rather interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
WPS Resources Corp.	4	Negative	The interpretation for CIP-006 significantly expands the scope of the standard and needs to go through through the SAR process. The inclusion of communications network wiring is a shift from previous industry understanding and is contrary to responses for Frequently Asked Questions posted on the NERC website.
Response: The RFI response drafting team does not expand the meaning of but rather interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
AEP Service Corp.	5	Negative	Although we agree that a true "systems" approach to data protection would also include the data paths, we are concerned about an element that we believe should be included in any determination of communication path physical security. Physical protection (given the relatively controlled locations of some of the data paths in question) should be determined by a risk-based assessment. This would be particularly focused on the likelihood of intrusion given the overall physical environment and other factors (cables buried, guard forces, monitoring cameras, etc.), some of which may qualify as acceptable alternative measures. We believe that this topic should be addressed during the formal development of the next iteration of CIP standards to clarify requirements and include risk factors and a rational, realistic approach. For example, securing a facility housing coal handling systems makes complete sense from a potential intrusion perspective. This is less the case with the cabling running externally from the facility to the control room, often buried and not easily or inobtrusively accessible. Because of the factor listed above, AEP is casting a negative vote for this interpretation. We would prefer that it be addressed fully during the development of the next set of NERC CIP standards.
Response:			

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The RFI response drafting team agrees that this is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Allegheny Energy Supply Company, LLC	5	Negative	Allegheny Energy is concerned with the SAR drafting team interpretation that wiring within an ESP be considered a Cyber Asset or Critical Cyber Asset. Allegheny Energy agrees that the wiring (and information transmitted by such wiring) within an ESP needs to be protected; however, Allegheny Energy does not agree that the wiring needs to be classified and protected as a defined cyber asset. NERC defines cyber assets as programmable electronic devices and communication networks including hardware, software, and data and does not include the language “including the wiring that comprises the physical media supporting the network”. Allegheny Energy believes the best method to determine protection measures for the wiring (and information transmitted by such wiring) is to create a holistic approach to communication network and data communication link protection through the Standards process that specifically addresses these issues. This new Standard could address communication network and data communication link security issues, including copper cabling, fiber optic cabling, and wireless implementations. By the interpretation stating that network wiring is a cyber asset or potentially a critical cyber asset in an effort to physically secure the wiring, this statement would additionally impose all of the requirements of the CIP standard that are applicable to cyber assets and in essence make entities non-compliant since many requirements cannot be accomplished for wiring.
Response: The RFI response drafting team agrees that this is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. As such the RFI response drafting team has clarified that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
City of Tallahassee	5	Negative	CIP-005-1, R1.3 states: "Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s)."

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			Since it is not within the Electronic Security Perimeter, it does NOT need to be within a Physical Security perimeter that is required in CIP-006-1, R1.1. (Glossary) Cyber Assets: "Programmable electronic devices and communication networks including hardware, software, and data." I disagree that this includes the "wires". The "communication links connecting" are the "wires" and they are excluded per CIP-005, R1.3. We cannot have one standard saying the wires are included and another saying they are not!
Response: Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
Colmac Clarion/Piney Creek LP	5	Affirmative	Appears to adequately require either 'six boundary' enclosure or entity description of protective measures on wiring or components outside of same. Doesn't require that entity methods equal six wall protection however.
Response: Thank you for your comment. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Consumers Energy	5	Negative	Consumers Energy’s Comments to Accompany a “No” Vote on NERC 2008-10 August 6, 2008 **2008-10 Goes Beyond the Intent of the Standards** In extending the definition of Cyber Asset to include data and the communication network, the Interpretation clearly goes beyond the scope intended by the drafters of the Standards. CIP-002-1 R3, Critical Cyber Asset Identification, refers to several examples of possible Critical Cyber Assets, all of which can be considered computer systems, devices possessing a central processing unit. Seven of the nine requirements in CIP-007-1 refer to Cyber Assets and clearly are intended to apply to computer systems, not network cables or data. **Data and Cables Would Become Critical Cyber Assets** If this interpretation passes, network cables and data will be considered Cyber Assets. Since it is difficult to conceive of an Asset that uses a network where data and networks are not essential to the operation of that Asset, data and network cabling will become Critical Cyber Assets. This will be true for control centers, generating plants and substations. **Data as a Critical Cyber Asset** The act of identifying data as a Critical Cyber Asset has far-reaching implications. Will removable media such as backup tapes need to be stored within an Electronic Security Perimeter? How can media so protected be

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			moved to an off-site storage location? **Actual Intent - Cyber Asset Has CPU** Consumers Energy suggests the actual intent of the CIP Standards is to define as a Cyber Asset only those devices with a central processing unit. These are the devices susceptible to remote attack and compromise. Consumers Energy further suggests the primary intent of the present version of the CIP Standards is to protect against remote compromise. **Intent of Interpretation Goes Too Far for This Stage** Consumers Energy also suggests that the apparent intent of the Interpretation, to require all network cabling be protected by a six-wall boundary, goes beyond the intent of the CIP Standards in their present form. CIP-006-1 R1.1 states “ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter.” This does not require a piece of hardware without a CPU, such as a network cable, to reside within a six-wall boundary. Consumers Energy argues that protecting network cabling residing in an area entirely within the control of the Responsible Entity is beyond the scope of the present CIP Standards. Had the intent of the requirement been to include all connections outside the ESP, the wording should have stated such. Threats and Priorities If the apparent intent of the Interpretation, to require network cabling to be contained within a six-wall boundary, is accepted, there will be no distinction between “in-house” cabling and connections carried through public networks. This ignores the different threat exposure of the two types of communication circuits. This Interpretation will divert money and other resources from mitigating higher threat exposures, such as man-in-the-middle attacks on unencrypted external communications circuits, to this lower threat exposure. **Proposed Rewording** Consumers Energy proposes the following wording to replace the existing interpretation: Response: CIP-006-1 R1.1 refers to “any externally connected communication end point (for example, dial-up modems)” as specifically identified as an access point to the Electronic Security Perimeter. The use of “externally connected” in this context refers to communication facilities outside the control of the Responsible Entity. Examples of such connections would include dial-up or leased telephone or data circuits, commercial packet-switched networks, wireless networks, or the Internet. Examples of connections not considered to be ”external” would include local area networks between floors in a building or between buildings in a campus environment.

Response:

On the matter of wiring, it is clear that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset.

The RFI response drafting team agrees and acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also notes that Critical Cyber Asset classification is an important issue and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. Therefore, the

Entity	Segment	Vote	Comment
matter of data protection is not directly address by this RFI response. The drafting team does not agree that protection of only Cyber Assets with CPUs is the intent of the CIP standards. The drafting team believes that the requirement clearly states that “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. The RFI response drafting team appreciates the suggested replacement wording, but believes it does not meet the objective of CIP-006-1.			
Detroit Edison Company	5	Negative	The following are Detroit Edison's reasons for voting No: The NERC Glossary defines Cyber Assets as “Programmable electronic devices and communication networks including hardware, software, and data”. Detroit Edison believes that this definition relating to the network is to include active devices that comprise the network, not the transmission media itself. Thus routers, switches, hubs, etc. are cyber assets, wiring is not. Detroit Edison's opinion on protecting cabling between physical security perimeters fully contained within an otherwise adequately secured facility is that the cable is sufficiently protected following guidance provided by NIST. Additional protection can be provided by covering the cable trays where they are easily accessible. "NIST SP800-53 PE-4 Access Control For Transmission Medium, Supplemental Guidance: Physical protections applied to information system distribution and transmission lines help prevent accidental damage, disruption, and physical tampering. Additionally, physical protections are necessary to help prevent eavesdropping or in transit modification of unencrypted transmissions. Protective measures to control physical access to information system distribution and transmission lines include: (i) locked wiring closets; (ii) disconnected or locked spare jacks; and/or (iii) protection of cabling by conduit or cable trays." Note that conduit and cable tray is specified as adequate protection by NIST however, if the interpretation is approved as written a completely enclosed six wall boundary would be required. Does this mean that all conduit bodies, pull boxes, cable tray covers, and open cable trays would become access points subject to CIP-006? "FERC Order 706 paragraph 224: Congressional Representatives state that NIST research prepared a technical report comparing the proposed CIP Reliability Standards with SP 800-53. This technical report found that an organization conforming to the baseline set of security controls in SP 800-53 will also comply with the management, operational and technical security requirements of the CIP Reliability Standards, though the converse may not be true." Detroit Edison believes that the outer barrier cable jacket, designed and manufactured to protect the data transport media within the jacket, represents a comprehensive six wall cable barrier and furthermore, completely enclosing wiring between physical security perimeters with a second protective measure such as a conduit, would be unduly burdensome, increase the risk of creating adjacency hazards and would not significantly improve the security posture of the critical cyber assets in the electronic security perimeter. Detroit Edison further supports the use of alternative protective measures such as data encryption where technically feasible, over the use of conduit,

Entity	Segment	Vote	Comment
			which significantly provides enhanced security over the use of conduit alone.
Response: On the matter of wiring, it is clear that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The examples of cable protection cited in the comment appear to be viable physical approaches; however, the conclusion that a six-wall bounded physical solution is the only acceptable one is not accurate. The Requirement R1.1 of CIP-006-1 clearly states that “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
FirstEnergy Solutions	5	Negative	FE thanks the SAR team for their efforts in developing an interpretation for CIP-006-1 Req. R1.1 in response to Progress Energy's request. However, we have cast a Negative vote for the following reasons and ask the team to consider our comments and suggested revision. We feel that the proposed interpretation fails to provide the industry with a clear direction related to the question posed by Progress Energy. As stated, the interpretation largely restates the definition of a Cyber Asset contained in the NERC Glossary of Terms, and a re-statement of CIP-006 R1.1. The interpretation states that "The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." However, the actual definition from the NERC Glossary states that “Cyber Assets include programmable electronic devices and communication networks including hardware, software, and data." Further, in the CIP standards development process the communications paths were deliberately excluded from the scope of the Standards, especially third party communication assets. Accordingly, we concur with the aspect of the interpretation that implies that the communications hardware devices and closets that include critical cyber assets should be secured inside the PSP, but that the physical utility-owned wiring should not be classified as Cyber Asset as the interpretation indicates. This would be consistent with the explicit exclusion of the third party communication assets embodied within the standards. We agree that the definition includes the data as a Cyber Asset, but do not agree that the definition includes the physical wiring as a Cyber Asset. Accordingly as a potential modification to the interpretation, we suggest a revision to the interpretation as follows: "The definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: The RFI response drafting team asserts that physical media (wiring) is a component of a communication network within an ESP and shall be secured inside the Physical Security Perimeter.			

Entity	Segment	Vote	Comment
The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Lincoln Electric System	5	Affirmative	Any wiring within the electronic security perimeter must be protected by a six-wall physical security perimeter. Wiring external to the electronic security perimeter constitutes a "communications link", and therefore does not need to be protected by the physical security perimeter. It appears that some confusion on this issue stems from the fact that Progress Energy's original question isn't even possible - it pertains to wiring within the electronic security perimeter, but outside the physical security perimeter. According to Requirement 1.1, the electronic security perimeter must be a subset of the physical security perimeter. Therefore, any wiring within the electronic security perimeter must also fall within the physical security perimeter by default.
Response: Thank you for your comment. The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.			
Manitoba Hydro	5	Negative	Manitoba Hydro agrees with the part of the interpretation provided by the SAR drafting team that protection of the data transmitted over wires within an Electronic Security Perimeter as the intent of the requirement. This provides more flexibility to meet the standard by allowing not only physical protection of the wire, but also alternative protective measures for the data such as encryption. Responsible Entities should take reasonable measures to protect the data within an Electronic Security Perimeter. However, Manitoba Hydro does not agree with the part of the interpretation provided by the SAR drafting team that "the definition of a Cyber Asset includes both the data and communication networks, including the wiring that comprises the physical media supporting the network." It should be made clear that the wiring within an Electronic Security Perimeter is considered as part of the Cyber Asset (programmable device or communication network) and that wiring is not itself a Cyber Asset. Since the term communication network is not a NERC defined or clearly understood industry term, the interpretation should not use communication network (or network) as part of any clarifying statement.
Response: The RFI response drafting team agrees and submits a revised interpretation response stating the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. However, the drafting team disagrees with removal of the term communication network in the RFI response, as it already referenced in the NERC Glossary.			

Entity	Segment	Vote	Comment
Northern States Power Co.	5	Negative	While Xcel Energy generally supports what we understand to be the intent of the interpretation, we feel it is not clear and could create further ambiguity. An interpretation should be clear and not create further room for interpretation. As explained to us by a member of the Cyber Security Order 706 SAR Drafting Team, the interpretation is designed to address the situation where there are potentially two separate physical security perimeters (PSP) with assets that are part of the same ESP -- such as two separate rooms, a data center and an operations center, that both have critical cyber assets and individual physical security perimeters. You could still have one ESP for the single building -- however, since the wiring connecting the assets in each of these rooms leaves the physical security perimeters, you need to protect the wiring with a physical boundary (conduit), or encrypt the data. We feel strongly that this interpretation, as written, could be implemented and/or enforced inconsistent with what the drafting team intended, and recommend a new draft of the interpretation, including a diagram, be developed. Also, since this interpretation will likely have a substantial impact on entities, an implementation plan should be considered.
Response: The RFI response drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope. The team understands the desire for more specificity and prescription, such as in a diagram, but believes that could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Pacific Gas and Electric Company	5	Negative	The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of “alternative protective measures” i not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			

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PPL Generation LLC	5	Negative	Response: The definition of a Cyber Asset includes both the data and the routable protocol-based communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures. Alternative protection measures could include 24 x7 monitoring, alerting, and logging of attempts at or actual compromise of the network. Supporting information: Based on CIP-002, R3, the definition introduced by the Interpretation should be limited to the "routable protocol-based" communication networks associated with Cyber Assets.
Response: The RFI response team agrees with the comment that the objective is to protect the data. To do so requires measures to prevent tampering of Cyber Assets. However, the RFI response team disagrees with the last point. The drafting team asserts that the requirement R1.1 does not limit application of alternative measures only to “routable protocol-based communication networks” and therefore doing so is unjustified.			
Reliant Energy Services	5	Negative	Reliant Energy is in agreement with the following comment posted by First Energy at 3:54 pm on August 13, on PJM’ NERC Standard e-Room. That is; “he definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly; the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: On the matter of wiring, it is clear that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team agrees that protection can be provided through alternative measures that include use of a combined/complementary physical and logical approach to achieve the same or better protection.			
Salt River Project	5	Negative	In cases where the building hosting the Critical Asset is under control of the Registered Entity, the building itself should serve as the six sided physical container. The possibility of an employee, contractor or guest pulling up a floor panel or ceiling tile, finding the right cable or fiber, and then having a way to tap or monitor the line is not a credible threat
Response: The building hosting the Critical Asset, when under the control of the Responsible Entity, is a qualified Physical Security Perimeter only when access is controlled per CIP-006-1 and all personnel with unescorted access have met the applicable requirements of the CIP standards, including completion of personnel risk assessments and training. If the entire building is not a qualified PSP, then alternative measures must be applied to protect wiring not enclosed within the qualified PSP(s) within the building.			

Entity	Segment	Vote	Comment
Southern California Edison Co.	5	Negative	Southern California Edison Company (SCE) SCE appreciates the opportunity to provide comments on the NERC Standards Development team' proposed interpretation for CIP-006-1's Requirement 1.1 (Proposed Interpretation). SCE cast a negative vote on the Proposed Interpretation because it causes additional confusion and could result in unreasonable and impractical consequences that would not improve the security of the Cyber Assets or the Electronic Security Perimeter. SCE believes issues identified by Progress Energy should be addressed during the review of CIP-006 scheduled to take place in 2009. Supporting reasons for this position are provided below. The proposed interpretation states that Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." CE shares a concern raised by WECC in their position paper that if the physical media used to transport critical data is considered a Critical Cyber Asset, then it would require all of the requisite physical protections specified in the existing CIP standards. SCE feels physical media supporting the network cannot be subject to the physical protections specified in CIP standards. For example, if a network cable runs from a Critical Cyber Asset situated within an identified Physical Security Perimeter to a point or through any area that is outside the identified Physical Security Perimeter, it is not clear that taking measures to protect the cable from tampering, and potentially having to monitor access to the cable, would be an appropriate way to secure the network. Access to SCE's communications network, and the data which streams across it, is strictly controlled by an Electronic Security Perimeter which personnel and equipment/ application(s) are given narrow access rights dependent on their usage requirements. The allowance of "alternative protective measures" for physical media supporting the network is also not clearly defined, and could even be interpreted to allow for logical protections without physical protection of Cyber Assets. This clearly would not be an appropriate outcome as pointed out in WECC's position paper as well. The uncertainty created by the interpretation's reference to alternative protective measures is another reason SCE voted against the interpretation. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances. In closing, it is SCE's opinion that the Proposed Interpretation and the issues brought-up in relation to the actual definition of Cyber Asset be fully addressed and incorporated into the revised CIP-006 standard. Pursuant to NERC's Reliability Standards Development Plan an effort to revise the CIP standards will be initiated in 2009.

Response:

The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project.

However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.

The drafting team recognizes there are instances that pose technical and/or costly challenges to protection of Cyber Assets and clarifies that the current

Entity	Segment	Vote	Comment
Requirement includes the use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. To the commenter's point regarding more prescriptive and specific language, the drafting team believes that it could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Tampa Electric Co.	5	Negative	Tampa Electric Company's Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry's attention and attempting to clarify this issue. Tampa Electric Company has several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach may be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: • These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. • The primary DCS vendors in our environment have stated to us that they do not offer or support an approved mechanism for firewalling within the DCS network or encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. • The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, Tampa Electric recommends that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations. We believe

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			that the Standard Authorization Request should be modified to address concerns and issues related to: • Unauthorized access to the ESP through access to physical cabling. • Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.
Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets "alternative measures" to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Tennessee Valley Authority	5	Negative	The factors, which lead to this conclusion, are the exponential increase in scope and cost for the implementation of physical security applied to the communication media.
Response: CIP-006-1 requires all Cyber Assets within an ESP to be enclosed within a PSP. The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets "alternative measures" to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden.			
U.S. Bureau of Reclamation	5	Negative	This issue raises a question as to the NERC requirements for the physical protection of critical cyber assets that fall outside of readily defined Physical Security Perimeters (PSPs). The connection between the two PSPs is a communications line employing a routable protocol and may be based on microwave, radio, copper, or fiber technologies. For circuits that go between physical structures separated by more than several feet, the 6 wall requirement is impractical. NERC's response to the question raised was consistent with their overall requirements in the sense that they did not relax protection requirements for Critical Cyber Assets (specifically wiring) external to an Electronic Security Perimeter (ESP). Reclamation will be significantly impacted by this interpretation for its Critical Cyber Systems that extend over several physical sites. Specifically in cases where those sites are interconnected with communications circuits employing "routable protocols." In those instances, since physical protection of the circuits will be impractical or impossible, Reclamation will need to employ "alternate protective measures" on communications lines interconnecting the physically distinct sites. We suggest NERC reconsider their requirements in cases where interconnections between sites remain within the same "control system" and where those interconnections are carried over privately owned circuits. The

Entity	Segment	Vote	Comment
			requirements NERC has outlined make very good sense (and we support them) where the connections go to external entities or where they are carried over public networks. We have no desire to change this aspect of the requirements. We are requesting special consideration be given to private networks between physical and electronic perimeters where those networks are owned/operated by the entities in question.
Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets “alternative measures” to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. The RFI response team is limited to interpreting the requirement of the existing standard. The request for consideration of private networks is best addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project.			
AEP Marketing	6	Negative	Physical protection (given the relatively controlled locations of some of the data paths in question) should be determined by a risk-based assessment. This would be particularly focused on the likelihood of intrusion given the overall physical environment and other factors (cables buried, guard forces, monitoring cameras, etc.), some of which may qualify as acceptable alternative measures. We believe that this topic should be addressed during the formal development of the next iteration of CIP standards to clarify requirements and include risk factors and a rational, realistic approach. For example, securing a facility housing coal handling systems makes complete sense from a potential intrusion perspective. This is less the case with the cabling running externally from the facility to the control room, often buried and not easily or in obtrusively accessible. Because of the factor listed above, AEP is casting a negative vote for this interpretation. We would prefer that it be addressed fully during the development of the next set of NERC CIP standards.
Response: The RFI response drafting team agrees that this is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Consolidated Edison Co. of New York	6	Negative	The interpretation is not clear and may modify the intention of the Standard and needs more work. The existing Standard requirement clearly states, "..all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring			

Entity	Segment	Vote	Comment
needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
FirstEnergy Solutions	6	Negative	FE thanks the SAR team for their efforts in developing an interpretation for CIP-006-1 Req. R1.1 in response to Progress Energy's request. However, we have cast a Negative vote for the following reasons and ask the team to consider our comments and suggested revision. We feel that the proposed interpretation fails to provide the industry with a clear direction related to the question posed by Progress Energy. As stated, the interpretation largely restates the definition of a Cyber Asset contained in the NERC Glossary of Terms, and a re-statement of CIP-006 R1.1. The interpretation states that "The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." However, the actual definition from the NERC Glossary states that Cyber Assets include programmable electronic devices and communication networks including hardware, software, and data." Further, in the CIP standards development process the communications paths were deliberately excluded from the scope of the Standards, especially third party communication assets. Accordingly, we concur with the aspect of the interpretation that implies that the communications hardware devices and closets that include critical cyber assets should be secured inside the PSP, but that the physical utility-owned wiring should not be classified as Cyber Asset as the interpretation indicates. This would be consistent with the explicit exclusion of the third party communication assets embodied within the standards. We agree that the definition includes the data as a Cyber Asset, but do not agree that the definition includes the physical wiring as a Cyber Asset. Accordingly as a potential modification to the interpretation, we suggest a revision to the interpretation as follows: "The definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: The RFI response drafting team asserts that physical media (wiring) is a component of a communication network within an ESP and shall be secured inside the Physical Security Perimeter. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple			

Entity	Segment	Vote	Comment
physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Lincoln Electric System	6	Affirmative	Any wiring within the electronic security perimeter must be protected by a six-wall physical security perimeter. Wiring external to the electronic security perimeter constitutes a "communications link", and therefore does not need to be protected by the physical security perimeter. It appears that some confusion on this issue stems from the fact that Progress Energy's original question isn't even possible - it pertains to wiring within the electronic security perimeter, but outside the physical security perimeter. According to Requirement 1.1, the electronic security perimeter must be a subset of the physical security perimeter. Therefore, any wiring within the electronic security perimeter must also fall within the physical security perimeter by default.
Response: Thank you for your comment. The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.			
Madison Gas and Electric Co.	6	Negative	We disagree with the interpretation because it adds language that needs further interpretation and does not address our confusion in the Standard regarding when data traveling over a network needs to be protected and when it does not. The interpretation implies the measures referenced in CIP006, R1.1, focus on preventing physical access that would allow data to be tampered with in transit. Can we assume the focus is not on preventing physical access that allows data to be gathered/inspected, but rather to prevent tampering with the data? If so, would using optical fibers carrying data communication between two physical security perimeters be a sufficient physical control, assuming fiber provides a higher level of security to protect the data from tampering. Do optical fibers contained within a continuous, fully-jacketed cable, the only end points of which are contained within separate six-sided physical security perimeters, meet the requirements of the Standard under this interpretation? If not, what constitutes the physical security perimeter and what constitutes a physical access point? Please provide guidance, including examples, on the "alternative protective measures" that would be acceptable to meet the standard. The standards are confusing because of the explicit exemption under the Introduction section, Item 4.2.2, of each standard that excludes "Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters." We assume "communication networks" and "communication links between discrete ESP's" are two different things, since they are referenced separately in other parts of the Standard. Communication links between discrete ESP's are referenced in CIP-005, R1.3, as being outside of the ESP. This reference does not help to clarify the exemption. In addition, communication networks are not referenced in CIP-005, R1.3, or anywhere else except in the definition of Cyber Assets. To say that communication networks are exempt from the Standard implies the data traveling on those networks are also exempt. If this is incorrect, what is NERC's interpretation of the explicit exemption? From a protection standpoint, if there is a difference between the wire and the data traveling across the wire, that needs to be explicitly defined. Where does the Standard state whether data traveling between ESP's does or does not have to be protected?

Entity	Segment	Vote	Comment
Response: The RFI response drafting team agrees that protection of data in motion is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. This request from Progress Energy must be addressed in the formal interpretation process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team disagrees with the commenter that exemption in R4.2.2 applies because the specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 indeed applies. In the revised response to Progress Energy, the drafting team interprets alternative measures to include approaches that are physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Manitoba Hydro	6	Negative	Manitoba Hydro agrees with the part of the interpretation provided by the SAR drafting team that protection of the data transmitted over wires within an Electronic Security Perimeter as the intent of the requirement. This provides more flexibility to meet the standard by allowing not only physical protection of the wire, but also alternative protective measures for the data such as encryption. Responsible Entities should take reasonable measures to protect the data within an Electronic Security Perimeter. However, Manitoba Hydro does not agree with the part of the interpretation provided by the SAR drafting team that "the definition of a Cyber Asset includes both the data and communication networks, including the wiring that comprises the physical media supporting the network." It should be made clear that the wiring within an Electronic Security Perimeter is considered as part of the Cyber Asset (programmable device or communication network) and that wiring is not itself a Cyber Asset. Since the term communication network is not a NERC defined or clearly understood industry term, the interpretation should not use communication network (or network) as part of any clarifying statement.
Response: The RFI response drafting team agrees and submits a revised interpretation response stating the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. However, the drafting team disagrees with removal of the term communication network in the RFI response, as it already referenced in the NERC Glossary.			
PP&L, Inc.	6	Negative	Response: The definition of a Cyber Asset includes both the data and the routable protocol-based communication network, including the wiring that comprises the physical media supporting the network. The

Entity	Segment	Vote	Comment
			intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures. Alternative protection measures could include 24 x7 monitoring, alerting, and logging of attempts at or actual compromise of the network. Supporting information: Based on CIP-002, R3, the definition introduced by the Interpretation should be limited to the "routable protocol-based" communication networks associated with Cyber Assets.
Response: The RFI response team agrees with the comment that the objective is to protect the data. To do so requires measures to prevent tampering of Cyber Assets. However, the RFI response team disagrees with the last point. The drafting team asserts that the requirement R1.1 does not limit application of alternative measures only to “routable protocol-based communication networks” and therefore doing so is unjustified.			
Salt River Project	6	Negative	In cases where the building hosting the Critical Asset is under control of the Registered Entity, the building itself should serve as the six sided physical container. The possibility of an employee, contractor or guest pulling up a floor panel or ceiling tile, finding the right cable or fiber, and then having a way to tap or monitor the line is not a credible threat
Response: The building hosting the Critical Asset, when under the control of the Responsible Entity, is a qualified Physical Security Perimeter only when access is controlled per CIP-006-1 and all personnel with unescorted access have met the applicable requirements of the CIP standards, including completion of personnel risk assessments and training. If the entire building is not a qualified PSP, then alternative measures must be applied to protect wiring not enclosed within the qualified PSP(s) within the building.			
Southern California Edison Co.	6	Negative	Southern California Edison Company (SCE) SCE appreciates the opportunity to provide comments on the NERC Standards Development team’s proposed interpretation for CIP-006-1’s Requirement 1.1 (Proposed Interpretation). SCE cast a negative vote on the Proposed Interpretation because it causes additional confusion and could result in unreasonable and impractical consequences that would not improve the security of the Cyber Assets or the Electronic Security Perimeter. SCE believes issues identified by Progress Energy should be addressed during the review of CIP-006 scheduled to take place in 2009. Supporting reasons for this position are provided below. The proposed interpretation states that “Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network.” SCE shares a concern raised by WECC in their position paper that if the physical media used to transport critical data is considered a Critical Cyber Asset, then it would require all of the requisite physical protections specified in the existing CIP standards. SCE feels physical media supporting the network cannot be subject to the physical protections specified in CIP standards. For example, if a network cable runs from a Critical Cyber Asset situated within an identified Physical Security Perimeter to a point or through any area that is outside the identified Physical Security Perimeter, it is not clear that taking measures to protect the cable from tampering, and potentially having to monitor access to the cable, would be an appropriate way to secure the network. Access to SCE’s communications network, and the data which streams across it, is strictly controlled by an

Entity	Segment	Vote	Comment
			Electronic Security Perimeter which personnel and equipment/ application(s) are given narrow access rights dependent on their usage requirements. The allowance of "alternative protective measures" for physical media supporting the network is also not clearly defined, and could even be interpreted to allow for logical protections without physical protection of Cyber Assets. This clearly would not be an appropriate outcome as pointed out in WECC's position paper as well. The uncertainty created by the interpretation's reference to alternative protective measures is another reason SCE voted against the interpretation. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances. In closing, it is SCE's opinion that the Proposed Interpretation and the issues brought-up in relation to the actual definition of Cyber Asset be fully addressed and incorporated into the revised CIP-006 standard. Pursuant to NERC's Reliability Standards Development Plan an effort to revise the CIP standards will be initiated in 2009.
Response: The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The drafting team recognizes there are instances that pose technical and/or costly challenges to protection of Cyber Assets and clarifies that the current Requirement includes the use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. To the commenter's point regarding more prescriptive and specific language, the drafting team believes that it could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Tampa Electric Co.	6	Negative	Tampa Electric Company's Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry's attention and attempting to clarify this issue. Tampa Electric Company has several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach may be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level

Entity	Segment	Vote	Comment
			of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: ? These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. ? The primary DCS vendors in our environment have stated to us that they do not offer or support an approved mechanism for firewalling within the DCS network or encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. ? The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, Tampa Electric recommends that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations . We believe that the Standard Authorization Request should be modified to address concerns and issues related to: ? Unauthorized access to the ESP through access to physical cabling. ? Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. ? Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.
Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets “alternative measures” to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Xcel Energy, Inc.	6	Negative	While Xcel Energy generally supports what we understand to be the intent of the interpretation, we feel it is not clear and could create further ambiguity. An interpretation should be clear and not create further room for interpretation. As explained to us by a member of the Cyber Security Order 706 SAR Drafting Team, the interpretation is designed to address the situation where there are potentially two separate physical security perimeters (PSP) with assets that are part of the same ESP -- such as two separate rooms, a data center and an operations center, that both have critical cyber assets and individual physical security perimeters. You could

Entity	Segment	Vote	Comment
			still have one ESP for the single building -- however, since the wiring connecting the assets in each of these rooms leaves the physical security perimeters, you need to protect the wiring with a physical boundary (conduit), or encrypt the data. We feel strongly that this interpretation, as written, could be implemented and/or enforced inconsistent with what the drafting team intended, and recommend a new draft of the interpretation, including a diagram, be developed. Also, since this interpretation will likely have a substantial impact on entities, an implementation plan should be considered.
Response: The RFI response drafting team has clarified what it interprets "alternative measures" to mean in the revised response and believes the phrase "alternative measures" is neutral in its scope. The team understands the desire for more specificity and prescription, such as in a diagram, but believes that could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
California Energy Commission	9	Negative	The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to "wires within a given facility or campus" and therefore doing so is unjustified. The drafting team has clarified what it interprets "alternative measures" to mean in the revised response and believes the phrase "alternative measures" is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Commonwealth of Massachusetts Department of Public Utilities	9	Negative	The interpretation should not include speculation as to the intent of the reliability standard.
Response:			

Entity	Segment	Vote	Comment
The RFI response drafting team does not speculate but rather interprets the standard as permitting "alternative measures" to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Oregon Public Utility Commission	9	Negative	The interpretation should not include speculation as to the intent of the standard. The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: The RFI response drafting team does not speculate but rather interprets the standard as permitting "alternative measures" to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response, and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset and would thus not qualify in and of itself as a Critical Cyber Asset. The drafting team believes the phrase "alternative measures" is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Electric Reliability Council of Texas, Inc.	10	Negative	This interpretation is an issue that should be handled through the full Standard review process.
Response: The RFI response drafting team agrees that this is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is			

Entity	Segment	Vote	Comment
among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Midwest Reliability Organization	10	Negative	MRO Response: CIP-005-1, R1.3 states: "Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s)." Since it is not within the Electronic Security Perimeter, it does NOT need to be within a Physical Security perimeter that is required in CIP-006-1, R1.1. (Glossary) Cyber Assets: "Programmable electronic devices and communication networks including hardware, software, and data." The MRO disagrees that this includes the "wires". The "communication links connecting" are the "wires" and they are excluded per CIP-005, R1.3. We cannot have one standard saying the wires are included and another saying they are not!
Response: Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
SERC Reliability Corporation	10	Negative	The interpretation indicates that the definition of a Cyber Asset includes the wiring that comprises the physical media supporting the [communications] network -- although this is not included in the NERC Glossary definition. The interpretation goes on to state that the intent is to protect the “data” transmitted over the network within the Electronic Security Perimeter rather than to protect “the facilities, systems, and equipment which if destroyed, degraded, compromised or otherwise rendered unavailable, would affect the reliability of the Bulk Electric System as a whole, not risk to a Responsible Entity’s individual asset” as described in Security Guidelines for the Electric Sector: Identifying Critical Assets. The interpretation merely restates the requirement of CIP-006-1, R1.1 to take (either Physical Security Perimeter or alternative) measures to control physical access of Critical Cyber Assets and adds confusion to the standard by introducing concepts contrary to other reference material provided by NERC.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			

Entity	Segment	Vote	Comment
Southwest Power Pool	10	Negative	SPP believes the concerns raised in this interpretation are too important to let lie in an interpretation. Although the interpretation provides additional guidance about the intent of the standard, it is not good practice to keep the requirement as written. A rewrite of R1.1 under a clear scope is a better way for the industry to understand the intent.
Response: The RFI response drafting team agrees that this is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Western Electricity Coordinating Council	10	Negative	“The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus.” “If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of “alternative protective measures” is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.”
Response: The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Interpretation - CIP-006 - Cyber Security — Physical Security of Cyber Security Assets (Project 2008-10)
Date of Initial Ballot: September 30, 2009 – October 12, 2009

Summary Consideration:

The interpretation drafting team thanks all who commented during the last posting of the revised interpretation for their interest and feedback. Commenters from the last posting of the revised interpretation provided constructive comments and concerns. The interpretation drafting team identified two general themes in the comments:

1. **Disagreement concerning whether wiring is a "Cyber Asset." Several commenters expressed concern that interpreting wiring within the definition of "Cyber Asset" expanded the requirements of the standard; and**
2. **That CIP-006-1, requirement R1.1 does not specifically discuss particular options that may be used as alternatives to a completely enclosed ("six-wall" border) and should not be addressed by this interpretation.**

In response to the comments received and reflective of the team's revisions to the interpretation, the interpretation drafting team responded as follows:

The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.

The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Edward P. Cox	AEP Marketing	6	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), AEP has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Brock Ondayko	AEP Service Corp.	5	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), AEP has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Jason L. Murray	Alberta Electric System Operator	2	Negative	The AESO agrees that use of encryption and other logical access control methods may be sufficient in some cases, however that is not what the standard calls for. Logical access controls cannot provide physical protection, and the standard clearly calls for physical protection. Thus, this interpretation would have the effect of changing the standard. Standards are not to be changed through an interpretation. If the standard needs to be changed, then the AESO recommends that a drafting team be assembled to propose changes to the standard requirements.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Negative	Wiring itself does not possess programmable intelligence, is not a cyber asset, and should not require the protection as detailed in CIP-006-1, R1. This level of protection will require entities to make considerable investments into atypical cable protection methods without a correpsonding gain in protection of the cyber assets within the ESP or the reliability of the Bulk Electric System.
Response: Thank you for your comment. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring. The drafting team has revised the interpretation.				

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	Requirement R1.1 does not specifically discuss wiring. However, the interpretation results in expanding this requirement.
Response: Thank you for your comment. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring. The drafting team has revised the interpretation.				
Paul B. Johnson	American Electric Power	1	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), AEP has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Raj Rana	American Electric Power	3	Negative	n reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), AEP has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Jason Shaver	American Transmission Company, LLC	1	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), ATC has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Neither Requirement R1.1 (CIP-006-1) nor Requirement 3 (CIP-002-1) specifically discuss or identify wiring as a cyber asset which would need protection within a six wall barrier.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Paul Rocha	CenterPoint Energy	1	Negative	Upon further review of the interpretation provided for CIP_006-1 - R1.1, CenterPoint Energy agrees with the concerns of American Electric Power (AEP). The first part of R1.1 requires that "all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. " Therefore, it is our conclusion that the interpretation includes reference to a condition that should not occur if the entity is to be in compliance with CIP_006-1 - R1.1. Specifically, the statement pertaining to "wiring within the Electronic Security Perimeter that is external to a Physical Security Perimeter,..." should not occur (according to the requirements of R.1.1) and adds a level of complexity to what components/assets are covered and what is expected for compliance.
Response: Thank you for your comment. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring. The drafting team has revised the interpretation.				
Daniel Herring	Detroit Edison Company	4	Negative	Detroit Edison's opinion is this interpretation is unnecessary and that protecting cabling between physical security perimeters fully contained within an otherwise adequately secured facility is that the cable is sufficiently protected following guidance provided by NIST for use in our nuclear plants.
Response: The IDT thanks you for your comment. While the team believes that this comment suggests a good practice, it believes that the comment is beyond the scope of the interpretation.				
Jalal (John) Babik	Dominion Resources, Inc.	3	Negative	Dominion cannot approve this interpretation without fully understanding what is meant by "Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				

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Mike Garton	Dominion Resources, Inc.	5	Negative	Dominion cannot approve this interpretation without fully understanding what is meant by 'Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Louis S Slade	Dominion Resources, Inc.	6	Negative	Dominion cannot approve this interpretation without fully understanding what is meant by "Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
William L. Thompson	Dominion Virginia Power	1	Negative	Dominion cannot approve this interpretation without fully understanding what is meant by "Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Douglas E. Hils	Duke Energy Carolina	1	Negative	Thank you for the opportunity to vote on this interpretation. We think that the interpretation is unclear and believe that this issue is best addressed in a comprehensive manner in a revision to the CIP standards.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Walter Yeager	Duke Energy Carolina	6	Negative	Thank you for the opportunity to vote on this interpretation. We think that the interpretation is unclear and believe that this issue is best addressed in a comprehensive manner in a revision to the CIP standards."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is				

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Edward C Stein	Edward C Stein	8	Negative	So you have a system where you can detect when someone has gained "unauthorized access" and you discover that someone has gained unauthorized access, does this mean that you have violated some Standard somewhere. In today's world where the use of the internet is required to exchange market and transmission data to RTOs, I believe that it is impossible to protect yourself from a hacker. The interpretation is politically correct but is does not prevent hacking.
Response: The drafting team thanks you for your comment. While the team appreciates your concern, it believes that this issue is beyond the scope of the interpretation.				
Kent Saathoff	Electric Reliability Council of Texas, Inc.	10	Affirmative	For clarity, we suggest that NERC add a comment in guidelines or FAQs to reflect that steel conduits are acceptable as a 6-wall enclosure for wiring.
Response: The drafting team thanks you for your comment. While the team appreciates your concern, it believes that this issue is beyond the scope of the interpretation.				
John J. Blazekovich	Exelon Energy	1	Negative	Exelon believes that this interpretation, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the “alternative measures” question that is beyond the scope of this interpretation.				
Kim Warren	Independent Electricity System Operator	2	Negative	We reiterate our previous comment that although directionally the IESO is in favour of the intent of the interpretation, we believe the current interpretation wording may effectively modify the intention of the standard, which is inconsistent with NERC Reliability Standards Development Procedure. Whereas the standard clearly requires physical access control, the interpretation effectively relaxes and hence alters this requirement by permitting logical measures to control physical access. Although we believe the standard should be revised to allow alternative protective

Voter	Entity	Segment	Vote	Comment
				measures, that is not the issue being balloted. We believe revisions to CIP-006-1, Requirement R1.1 should be made in the future to specifically cater for logical measures to control physical access to the Critical Cyber Assets.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Elizabeth Howell	ITC Transmission	1	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), ITC has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Neither Requirement R1.1 (CIP-006-1) nor Requirement 3 (CIP-002-1) specifically discuss or identify wiring as a cyber asset which would need protection within a six wall barrier.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	The FAQ developed along with the original CIP standards specifically state that the standards are not intended to address the wires between facilities. While we agree that the suggested interpretation is a good idea for a future improvement to the standard, the interpretation process is intended to clarify what the standard says as originally drafted, not what we would like the standard to say. In the response to comments from the initial ballot, the drafting team pointed out that the FAQ is a reference document and not enforceable. While we agree this is true, it does point out what the intent of the drafting team was when writing the requirements and is thus critical to interpreting the CIP standards. Q11 in the FAQ is clear that the drafting team did not intend to include wiring. The drafting team stated that the requirement only applies to assets that are not owned by the Responsible Entity and that the Q11 in the FAQ only addressed non-owned assets. First, we assume that the drafting team is referring to leasing by thae statement "assets that are not owned" even though leasing is one form of ownership. Second, leasing of communications cirucits is only one example given in the answer to Q11 in the FAQ. Thus, we can't conclude that Q11 does not apply to all communication circuits. If

Voter	Entity	Segment	Vote	Comment
				the drafting team wants to apply the standard to the wiring in the request for interpretation, they need to submit a SAR to modify the standard.
Response: Thank you for your comment. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring. The drafting team has revised the interpretation.				
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Negative	Comments from the last ballot of this interpretation clearly show a strongly diverse set of opinions on the subject. While the RFI response drating team has done a diligent job of responding to those comments, it is clear that there will still be a strong divide on the issue. PSEG agrees with CAL ISO's position that this interpretation should not be "....what should have been done," Southern Company's position the "....it actually reresents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice....," ISO New England's position that "....the interpretation adds requirements that are not already part of the Standard...." and PJM's position that: "....the interpretation adds requirements that are not already part of the Standard. EIP-006 describes the requirements for physical access controls. An interpretation of a standard should not be confused with "what should have been done." The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including an explicit reference to data in transit over communication links between discrete perimeters, the interpretation moves into an area which the standard intentionally does no address." PSEG believes that the only appropriate was to reach agreement on Progress Energy's question is to submit a SAR to address the issue via the standards approval process. If the team is unwilling to have the question settled by the SAR process, then, at a minimum,an appropriate implementation schedule must also be issued."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Thomas Piascik	PSEG Power LLC	5	Negative	Comments from the last ballot of this interpretation clearly show a strongly diverse set of opinions for the subject. While the RFI response drafting team has done a diligent job of responding to those comments, it is clear that there will still be a strong divide on the issue. PSEG agrees with CAL ISO's position that this interpretation should not be "...what should have been done.", Southern Company's

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Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Kenneth D. Brown	Public Service Electric and Gas Co.	1	Negative	Comments from the last ballot of this interpretation clearly show a strongly diverse set of opinions for the subject. While the RFI response drafting team has done a diligent job of responding to those comments, it is clear that there will still be a strong divide on the issue. PSE&G agrees with CAL ISO's position that this interpretation should not be "...what should have been done.", Southern Company's position that "...it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice...", ISO New England's position that "...the interpretation adds requirements that are not already part of the Standard..." and PJM's position that "...the interpretation adds requirements that are not already part of the standard. CIP-006-1 describes the requirements for physical access controls. An interpretation of a standard should not be confused with "what should have been done". The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including an explicit reference to data in transit over communications links between discrete perimeters, the interpretation moves into an area which the standard intentionally does not address." PSE&G

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Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Negative	"Comments from the last ballot of this interpretation clearly show a strongly diverse set of opinions for the subject. While the RFI response drafting team has done a diligent job of responding to those comments, it is clear that there will still be a strong divide on the issue. PSEG agrees with CAL ISO's position that this interpretation should not be "...what should have been done.", Southern Company's position that "...it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice...", ISO New England's position that "...the interpretation adds requirements that are not already part of the Standard..." and PJM's position that: "...the interpretation adds requirements that are not already part of the standard. CIP-006-1 describes the requirements for physical access controls. An interpretation of a standard should not be confused with "what should have been done". The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including an explicit reference to data in transit over communications links between discrete perimeters, the interpretation moves into an area which the standard intentionally does not address." PSEG believes that the only appropriate way to have agreement of Progress Energy's question is submit a SAR to address the issue via the standards approval process. If the team is unwilling to have the question settled by the SAR process, then, at a minimum, an appropriate implementation schedule must also be issued."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not				

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explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Kyle M. Hussey	Public Utility District No. 2 of Grant County	1	Affirmative	I agree with this interpretation. This clarifies that wiring can not only be secured through physical means but also logical.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, approved appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Henry Delk, Jr.	SCE&G	1	Negative	SCE&G does not think the interpetation adds enough clarity. The issue should be addressed during development of the next set of NERC CIP Standards.
Response: Thank you for the comment. The Interpretation Drafting Team has revised the interpretation so that it limits itself to the specific question about wiring, and other issues raised regarding CIP-006-1 will be addressed in future versions.				
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G does not think the interpretation adds enough clarity. The issue should be addressed during development of the next set of NERC CIP standards.
Response: Thank you for the comment. The Interpretation Drafting Team has revised the interpretation so that it limits itself to the specific question about wiring, and other issues raised regarding CIP-006-1 will be addressed in future versions.				
Martin Bauer	U.S. Bureau of Reclamation	5	Affirmative	While Reclamation agrees with the interpretation, it is contingent on the basis that no TFE is required when Alternative Measures are deployed.
Response: Thank you for the comment. The Interpretation Drafting Team has revised the interpretation so that consideration of alternative measures and whether a TFE is required are beyond the scope of this Request for Interpretation.				
Allen Klassen	Westar Energy	1	Negative	Do not agree with wire as a cyber asset
Response: Thank you for your comment. The drafting team agrees and has revised the interpretation.				

Voter	Entity	Segment	Vote	Comment
Linda Horn	Wisconsin Electric Power Co.	5	Negative	Wisconsin Electric is concerned with the use of the term "effective security". This does not identify what type of physical protection is equivalent to six wall borders. Does cabling protected by metallic conduit constitute effective security? Communication networks utilizing fiber optic cabling is very difficult to splice in a tap allowing unapproved logical access. Does fiber optic cable require the same protective measures as copper? There are still questions or clarification required.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	Wisconsin Electric is concerned with the use of the term "effective security". This does not identify what type of physical protection is equivalent to six wall borders. Does cabling protected by metallic conduit constitute effective security? Communication networks utilizing fiber optic cabling is very difficult to splice in a tap allowing unapproved logical access. Does fiber optic cable require the same protective measures as copper? There are still questions or clarification required.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Interpretation of CIP-006-x for Progress Energy (Project 2008-10)

The CIP-006-x for Progress Energy Drafting Team thanks all commenters who submitted comments on the interpretation for CIP-006-x for Progress Energy (Project 2008-10). These standards were posted for a 45-day public comment period from October 12, 2011 through November 21, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 17 sets of comments, including comments from approximately 56 different people from approximately 31 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Project2008-10_CIP-006_Interpretation_Progress.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. The NERC Board of Trustees indicated that the interpretation process should not be used to address requests for a decision on "how" a reliability standard applies to a registered entity's particular facts and circumstances. Do you believe this request for an interpretation is asking for clarity on the meaning of a requirement or clarity on the application of a requirement? ..... *X*
2. The NERC Board of Trustees indicated that in deciding whether or not to approve a proposed interpretation, it will use a standard of strict construction and not seek to expand the reach of the standard to correct a perceived gap or deficiency in the standard. Do you believe this interpretation expands the reach of the standard? .... *X*
3. Do you agree with this interpretation? If not, why not. .... *X*
4. Are there any other comments you would like to add that haven't been covered in the previous questions, please add them here. .... *X*

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kevin Perry		SPP	10
2.	Shon Austin		SPP	10
3.	Ron Ciesiel		SPP	10

2.	Group	Connie Lowe	Electric Market Policy, Information Technology Risk Management	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Dodson		RFC	1
2.	Sean Iseminger		SERC	5
3.	Mike Garton		NPCC	5
4.	Michael Gildea		MRO	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
5. Louis Slade		RFC 6										
6. Michael Crowley		SERC 3										
3. Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC	8
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Chantel Haswell	FPL Group, Inc.		5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy Macdonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

4. Group	Nick Wehner	ACES Power Marketing Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1. James Jones		Arizona Electric Power Cooperative/Southwest Transmission Company	WECC 1, 4, 5										
5.	Group	Steve Diebold	Kansas City Power & Light	X		X		X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Michael Gammon	KCPL	SPP	1, 3, 5, 6									
2.	Scott Harris	KCPL	SPP	1, 3, 5, 6									
3.	Dean Larson	KCPL	SPP	1, 3, 5, 6									
4.	Bob Beachy	KCPL	SPP	1, 3, 5, 6									
5.	Brett Holland	KCPL	SPP	1, 3, 5, 6									
6.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
7.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
8.	Individual	Michael Falvo	Independent Electricity System Operator		X								
9.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
10.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Anthony Jablonski	ReliabilityFirst										X
13.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
14.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
15.	Individual	Chris Higgins / Forrest Krigbaum & BPA CIP Team	Bonneville Power Administration	X		X		X	X				
16.	Individual	Rebecca Moore Darrah	MISO		X								
17.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

1. **The NERC Board of Trustees indicated that the interpretation process should not be used to address requests for a decision on "how" a reliability standard applies to a registered entity's particular facts and circumstances. Do you believe this request for an interpretation is asking for clarity on the meaning of a requirement or clarity on the application of a requirement?**

Summary Consideration:

Many commenters noted the request for interpretation is asking for clarity on the application of a requirement, while others noted the request for interpretation is asking for clarity on the meaning of a requirement. In general, the Interpretation Drafting Team ("IDT") agrees the Request for Interpretation ("RFI") asks in part for clarity on the application of the requirement ("*Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP*"). The IDT notes, however, that whether the requirement applies requires clarity on the meaning of the requirement ("*It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary*"). The IDT interpreted that "wire" is not part of the definition of "Cyber Asset," and that CIP-006-3c, R1.1, only applies to Cyber Assets, which provides clarity on the meaning and the application of the requirement.

Organization	Yes or No	Question 1 Comment
Kansas City Power & Light	The request is asking for clarity on the application of a requirement.	In this instance the request is asking for clarity in the application of the requirement, however, the interpretation response involved both the meaning of requirement CIP-002-1, R3 and the application of that meaning with CIP-006-1, R1.1.
Response: Thank you for your response. The IDT agrees the RFI appears to ask, in part, for clarity on the application of the requirement to a particular circumstance; however, the RFI also asks for clarity on the meaning of the requirement.		
ReliabilityFirst	The request is asking for clarity on the application	The last sentence of the Request for Interpretation reads (emphasis added): Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP. The meaning of the requirement appears to be reasonably clear. Progress

Organization	Yes or No	Question 1 Comment
	of a requirement.	Energy is requesting a determination of how to apply the requirement to a specific situation.
Response: Thank you for your response; the IDT agrees. The IDT agrees the RFI appears to ask, in part, for clarity on the application of the requirement to a particular circumstance; however, the RFI also asks for clarity on the meaning of the requirement.		
Southern Company	The request is asking for clarity on the application of a requirement.	The request specifically asks about the applicability of wiring.
Response: Thank you for your response; the IDT agrees. The IDT agrees the RFI appears to ask, in part, for clarity on the application of the requirement to a particular circumstance; however, the RFI also asks for clarity on the meaning of the requirement.		
Xcel Energy	The request is asking for clarity on the meaning of a requirement.	This request is defining what is considered a Critical Asset and not how to protect the Critical Assets.
Response: Thank you for the comment. The IDT agrees the interpretation provides clarity on the meaning of the requirement by clarifying that wire is not a Cyber Asset.		
Independent Electricity System Operator	The request is asking for clarity on the application	

Organization	Yes or No	Question 1 Comment
	of a requirement.	
Oncor Electric Delivery Company LLC	The request is asking for clarity on the application of a requirement.	
Southwest Power Pool Regional Entity	The request is asking for clarity on the meaning of a requirement.	
Electric Market Policy, Information Technology Risk Management	The request is asking for clarity on the meaning of a requirement.	
Northeast Power Coordinating Council	The request is asking for clarity on the meaning of a requirement.	
ACES Power Marketing Standards Collaborators	The request is asking for clarity on the	

Organization	Yes or No	Question 1 Comment
	meaning of a requirement.	
Manitoba Hydro	The request is asking for clarity on the meaning of a requirement.	
Northeast Utilities	The request is asking for clarity on the meaning of a requirement.	
Duke Energy	The request is asking for clarity on the meaning of a requirement.	
American Electric Power	The request is asking for clarity on the meaning of a requirement.	
American Transsmission Company, LLC	The request is asking for clarity on the meaning of a	

Organization	Yes or No	Question 1 Comment
	requirement.	
Bonneville Power Administration		
MISO		

2. The NERC Board of Trustees indicated that in deciding whether or not to approve a proposed interpretation, it will use a standard of strict construction and not seek to expand the reach of the standard to correct a perceived gap or deficiency in the standard. Do you believe this interpretation expands the reach of the standard?

Summary Consideration:

Most balloters agree the interpretation does not expand the reach of the standard. However, one commenter expressed concern that the interpretation restricts the reach of the standard. In general, the IDT does not share this view, and notes that it must follow the guidelines set forth in the Guidelines for Interpretation Drafting Teams (available at: http://www.nerc.com/files/Guidelines_for_Interpretation_Drafting_Teams_Approved_April_2011.pdf). The IDT considered the requirement language in the standard as written in order to provide clarity on the meaning of the standard, and the IDT believes that the meaning of the standard informs the proper reach of the standard.

Organization	Yes or No	Question 2 Comment
ReliabilityFirst	The interpretation does not expand the reach of the standard.	However, this interpretation greatly restricts the reach of CIP-006-3c R1.
Response: Thank you for your comment. While the IDT appreciates this concern, it disagrees that the interpretation restricts the reach of the standard. Rather, the purpose of the interpretation is to consider the language as written, within the Guidelines for Interpretation Drafting Teams, and to provide clarity on the meaning of the standard.		
Xcel Energy	The interpretation does not expand the reach of the standard.	The interpretation provided defines more clearly what should be included in the scope of standard.

Organization	Yes or No	Question 2 Comment
Response: Thank you for the comment, The IDT appreciates that its analysis of the language provides clarity.		
Southwest Power Pool Regional Entity	The interpretation does not expand the reach of the standard.	
Electric Market Policy, Information Technology Risk Management	The interpretation does not expand the reach of the standard.	
Northeast Power Coordinating Council	The interpretation does not expand the reach of the standard.	
ACES Power Marketing Standards Collaborators	The interpretation does not expand the reach of the standard.	

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	The interpretation does not expand the reach of the standard.	
Southern Company	The interpretation does not expand the reach of the standard.	
Manitoba Hydro	The interpretation does not expand the reach of the standard.	
Independent Electricity System Operator	The interpretation does not expand the reach of the standard.	
Northeast Utilities	The interpretation	

Organization	Yes or No	Question 2 Comment
	does not expand the reach of the standard.	
Duke Energy	The interpretation does not expand the reach of the standard.	
American Electric Power	The interpretation does not expand the reach of the standard.	
Oncor Electric Delivery Company LLC	The interpretation does not expand the reach of the standard.	
American Transmission Company, LLC	The interpretation does not expand the reach of the	

Organization	Yes or No	Question 2 Comment
	standard.	
MISO	The interpretation does not expand the reach of the standard.	
Bonneville Power Administration		

3. Do you agree with this interpretation? If not, why not.

Summary Consideration:

By overwhelming majority, most balloters agreed with the IDT's interpretation. However, there were some important minority viewpoints that the team considered. Almost universally, the viewpoints and concerns raised by commenters who did not agree with the interpretation were previously evaluated and considered in some manner during the development of the interpretation. In the responses that follow, and summarized here, the IDT explains the team's conclusions in developing the interpretation and how the team considered the comments. The team appreciated all of the comments and thanks participants for their input.

First, some commenters expressed concern that this interpretation conflicts with the interpretation in Appendix 1 of CIP-006-3c (see clarifying discussion, below, regarding usage of "Appendix 1" v. "Appendix 3" in reference to the interpretation developed by Project 2009-13). The IDT disagrees that this interpretation conflicts with Appendix 1, because there may be other scenarios beyond wiring for which Appendix 1 applies. Appendix 1 and this interpretation address different questions. This interpretation addresses whether wire is a Cyber Asset and Appendix 1 addresses alternative measures to a "six-wall" border for Cyber Assets.

Another commenter was concerned the interpretation would change the way standards are read and weaken the standard, but the IDT notes in its response the distinction between lists separated by "but not limited to" and the definition of "Cyber Asset," which is the subject of this interpretation. Furthermore, the IDT respectfully disagrees the interpretation weakens the standard, because the purpose of the interpretation is to consider the language as written, within the Guidelines for Interpretation Drafting Teams, and to provide clarity on the meaning of the standard.

In response to a comment that wire is a transport medium necessitating classification as a Cyber Asset and that wiring is an essential component of a network, the IDT explains that it respectfully disagrees on the bases that a transport medium is not the same as a communication network (and therefore not a Cyber Asset to which the requirement applies) and that essentiality of a component is not the criteria for application of the requirement in question.

One commenter noted the interpretation incorrectly referenced Appendix 3 of CIP-006-3c, and that the correct reference should be Appendix 1. In its interpretation, the IDT referred to the interpretation developed by Project 2009-13. That interpretation is now posted on the NERC Web site as Appendix 1 of CIP-006-3c; however, the interpretation developed by Project 2009-13 was Appendix 3 in the version of CIP-006-3c that accompanied the information for this project's (Project 2008-10) formal comment and successive ballot period materials. The numbering of the appendices in CIP-006-3c changed in September, 2011 (but not the content). The IDT agrees with the commenter that the reference should be corrected to refer to the latest posted version of CIP-006-3c, which is Appendix 1. Additionally, the IDT believes that it is clear from the context of the interpretation and the comments received that any references to "Appendix 3," both by commenters and the previously-posted version of this interpretation (Project 2008-10), refer to

the interpretation developed by Project 2009-13. In response to the comment, the IDT has changed the reference in the interpretation, which does not affect the substance of the interpretation. For purposes of these responses to comments, the IDT construes references to Appendix 1 and to Appendix 3 as references to the interpretation developed by Project 2009-13. As such, it is using the corrected reference to Appendix 1 in its responses for consistency, even if the commenter references Appendix 3.

Organization	Yes or No	Question 3 Comment
ReliabilityFirst	No	1. This interpretation is in direct conflict with Appendix 3 of CIP-006-3c. If wiring is not considered part of a network, then Appendix 3 of CIP-006-3c is not needed.2. This interpretation changes the way standards are read, and will require every reliability standard to be reviewed and possibly re-written. For example, FAC-008-3 R2.4.1 gives the scope as including, but not limited to, six types of equipment. If this interpretation passes, then FAC-008-3 will be read prescriptively. Any device not specifically listed will be out of scope for the requirement.3. From a cyber security perspective, this interpretation fatally weakens the protections of CIP-006-3c and CIP-005-3a. Running network cable outside of a Physical Security Perimeter without some form of compensating measure is exposing the data from within an ESP to possible compromise and attack.

Response: Thank you for your comments. The IDT discussed and evaluated all of these concerns in its deliberations of developing the interpretation. The following explanations, which correspond with the numbering of your comments, discuss the IDT's consideration of your concerns:

1) **The IDT disagrees that this interpretation is in direct conflict with Appendix 1 of CIP-006-3c (See explanation of "Appendix 1" v. "Appendix 3" usage in the Summary Consideration to Question 3, above). There may be other scenarios beyond wiring for which Appendix 1 applies.**
2) **The IDT respectfully disagrees. In the example given of FAC-008-3, and in many other standards' requirements, the language includes the phrase, "but not limited to," which specifically precludes a prescriptive reading of the enumerated items. Furthermore, the IDT is not changing the scope of what is enumerated in determining what is a Cyber Asset; instead, it is clarifying that "wire" is not explicitly included within the meaning of "communication network," which is enumerated in the language of the definition of "Cyber Asset."**
3) **While the IDT appreciates this concern, it disagrees that the interpretation weakens the protections of CIP-006 and CIP-005**

Organization	Yes or No	Question 3 Comment
because it is not contrary to any requirement to protect data.		
Southwest Power Pool Regional Entity	No	SPP RE does not agree with this interpretation for two reasons. 1. The NERC Glossary defines a Cyber Asset as "Programmable electronic devices and communication networks including hardware, software, and data." The wire is the transport medium for the data, and data is a cyber asset. CIP-006-3 R1.1 requires data to be protected; to protect the data, the wire must also be protected. 2. Wiring can be viewed as an essential component of the hardware comprising a network, further supporting the need to protect the wiring.
Response: The IDT thanks you for your comments. The IDT considered and evaluated these concerns in its deliberations. The following explanations, which correspond with the numbering of your comments, discuss the IDT's consideration of your concerns: **1. The IDT determined that wire is an underlying component of a Cyber Asset, much like air is the transport medium in a wireless network. However, wire or air itself is not a "communication network" (and therefore not a Cyber Asset), which is not contrary to CIP-006-3c, R1.1's requirement to protect data.** **The IDT appreciates this concern, but notes that it is outside the scope of the language of the definition of "Cyber Asset," and CIP-006-3c, R1.1's application is limited to Cyber Assets. Power and facilities are also essential components, but whether they are essential is not the criteria for application of CIP-006-3c, R1.1, which is the subject of this interpretation. The purpose of the interpretation is to consider the language as written, within the Guidelines for Interpretation Drafting Teams, and to provide clarity on the meaning of the standard.**		
Kansas City Power & Light	No	The question raised by Progress Energy is not clear enough for an appropriate interpretive response. As a result, the interpretive response may be including assumptions that were not stated in the question posed by Progress Energy. At any rate, it is recommended that Progress Energy be afforded the opportunity to resubmit their question with additional information and circumstances regarding the communications mediums leaving the Physical Security Perimeter under consideration.

Organization	Yes or No	Question 3 Comment
Response: The IDT thanks you for your comment, but it disagrees that the request for interpretation is not clear enough for an interpretive response. The IDT believes it has provided clarity to the meaning of the requirement through its analysis.		
Southern Company	Yes	However, the interpretation incorrectly refers to Appendix 3 of CIP-006-3c. The language should be corrected to refer to Appendix 1 of CIP-006-3c.
Response: The IDT thanks you for this comment. In its reference to "Appendix 3," the IDT referred to the interpretation developed by Project 2009-13. That interpretation is now posted as Appendix 1 of CIP-006-3c; however, the interpretation developed by Project 2009-13 was labeled as Appendix 3 in the version of CIP-006-3c that accompanied the information for this project's (Project 2008-10) formal comment and successive ballot period materials on the Project 2008-10 project page. The numbering of the appendices in CIP-006-3c changed in September, 2011 (but not the content). The IDT agrees with the commenter that the reference should be corrected to refer to the latest posted version of CIP-006-3c, which is Appendix 1. Additionally, the IDT believes that it is clear from the context of the comments received that references to "Appendix 3," both by commenters and the previously-posted version of this interpretation (Project 2008-10), refer to the interpretation developed by Project 2009-13. In response, the IDT has changed the reference in the interpretation, which does not affect the substance of the interpretation.		
Electric Market Policy, Information Technology Risk Management	Yes	
Northeast Power Coordinating Council	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Manitoba Hydro	Yes	
Independent Electricity	Yes	

Organization	Yes or No	Question 3 Comment
System Operator		
Northeast Utilities	Yes	
Duke Energy	Yes	
American Electric Power	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transsmission Company, LLC	Yes	
MISO	Yes	
Xcel Energy	Yes	
Bonneville Power Administration		

4. Are there any other comments you would like to add that haven't been covered in the previous questions, please add them here.

Summary Consideration:

Some commenters expressed concern about the distinction between Appendix 1 of CIP-006-3c and this interpretation (See explanation of "Appendix 1" v. "Appendix 3" usage in reference to Project 2009-13 in the Summary Consideration to Question 3, above). This interpretation is distinct because it only addresses whether wire is a "Cyber Asset." The IDT notes that, while Appendix 1 may have used "wire" as an example, Appendix 1 applies only upon a determination that something is a Cyber Asset. This interpretation clarifies that wiring is not a Cyber Asset.

One commenter thought the interpretation should have been an initial ballot, but the IDT notes that a successive ballot is appropriate under the current NERC Standard Processes Manual when making a substantive change to the previously-posted interpretation.

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration		BPA thanks you for the opportunity to comment on Project 2008-10 Interpretation of CIP-006-1 R1 for Progress Energy. BPA has no comments or concerns at this time.
Response: Thank you for your participation		
MISO		In general, the Midwest Independent Transmission System Operator (the "MISO") supports the revised interpretation of CIP-006-1, Requirement R1.1 (the "2008-10 Interpretation") developed by the CIP Interpretation Drafting Team (the "IDT"). In particular, MISO agrees with the IDT that wiring does not meet the definition of "Cyber Asset" in the NERC Glossary of Terms Used in Reliability Standards and that Requirement R1.1 therefore does not apply to wiring. MISO is concerned, however, that there is an inconsistency between the 2008-10 Interpretation and the interpretation in CIP-006-3c, appendix 3 ("Appendix 3"). Appendix 3 states that "[f]or Electronic Security Perimeter wiring external to a Physical Security Perimeter, the drafting team interprets [ ] Requirement R1.1 as not limited to measures that are 'physical in nature'" (emphasis added). This language implies that wiring is subject to Requirement R1.1. The 2008-10 Interpretation, however, states unambiguously that

Organization	Yes or No	Question 4 Comment
		wiring is not a Cyber Asset and is not subject to Requirement R1.1. The IDT is clearly aware of this inconsistency, as it included the following language in the interpretation:This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 3. The interpretation in CIP-006-3c, appendix 3c, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).This limitation of the 2008-10 Interpretation does not, however, resolve the identified inconsistency because Appendix 3 explicitly addresses wiring, which means it is not "distinct" from the 2008-10 Interpretation. Thus, while MISO supports the approval of the 2008-10 Interpretation, MISO also urges the IDT to amend Appendix 3 or otherwise clarify that Appendix 3 does not apply to wiring.
Response: Thank you for your comment. The IDT disagrees that this interpretation is in direct conflict with Appendix 1 of CIP-006-3c (See explanation of "Appendix 1" v. "Appendix 3" usage in reference to Project 2009-13 in the Summary Consideration of Question 3, above). There may be other scenarios beyond wiring for which Appendix 1 applies. The purpose of the interpretation is to consider the language as written, within the Guidelines for Interpretation Drafting Teams, and to provide clarity on the meaning of the standard. The IDT notes that, while Appendix 1 may have used "wire" as an example, Appendix 1 applies only upon a determination that something is a Cyber Asset. This interpretation clarifies that wiring is not a Cyber Asset.		
ReliabilityFirst		This ballot should not be a successive ballot, but rather an initial ballot, as the text of the interpretation has been completely changed.
Response: The IDT thanks you for your comment, but notes that a successive ballot was called for pursuant to the NERC Standards Processes Manual. While the text completely changed, it was a substantive change necessitating a successive ballot.		
Southwest Power Pool Regional Entity		We disagree with the assertion: "This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 3. The interpretation in CIP-006-3c, appendix 3, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter

Organization	Yes or No	Question 4 Comment
		(ESP)."The interpretation in CIP-006-3C, Appendix 3 is directly applicable to Interpretation of CIP-006-1 Cyber Security - Physical Security of Critical Cyber Assets for Progress Energy. The interpretation found in Appendix 3 does provide for alternative means other than physical protection for instances in which physical protection is not technically feasible. Implementation of those alternative means addresses instances in which data must traverse beyond a traditional "six-wall" boundary.
Response: The IDT thanks you for your comment. This interpretation is distinct because it only addresses whether wire is a "Cyber Asset." The IDT notes that, while Appendix 1 may have used "wire" as an example, Appendix 1 applies only upon a determination that something is a Cyber Asset. This interpretation clarifies that wiring is not a Cyber Asset. There may be other scenarios beyond wiring for which Appendix 1 applies.		
Southern Company		We would seek guidance or direction on how this interpretation applies to all versions of the approved standards. If this guidance is already available, please include a preamble providing how the interpretation will apply to all approved versions of the CIP-006 standard (i.e. CIP versions 1 through 4).
Response: The IDT thanks you for your question. An approved interpretation will be applied as equally relevant to all prior and subsequent versions of the standard to the extent the language of the relevant requirement language is the same in substance. The IDT anticipates that this interpretation, subject to industry, NERC Board of Trustees, and FERC approval, will be equally applicable to CIP-006, Versions 1 through Version 4 (The IDT notes that Version 4 remains pending as of this response, and its answer here assumes approval as filed by NERC to FERC).		
Electric Market Policy, Information Technology Risk Management		
ACES Power Marketing Standards Collaborators		

Organization	Yes or No	Question 4 Comment
Manitoba Hydro		
Independent Electricity System Operator		
Northeast Utilities		
Duke Energy		
American Electric Power		
Oncor Electric Delivery Company LLC		
American Transsmission Company, LLC		
Xcel Energy		

END OF REPORT

Exhibit D

Complete Record of Development of the Interpretation of Requirement R1.1 of CIP-006-4

Project 2008-10
Interpretation - CIP-006 - Cyber Security — Physical Security of Cyber Security Assets

Registered Ballot Body

Related Files

Status:
A recirculation ballot of the interpretation ended on December 19, 2011. The interpretation was approved by the ballot pool with a quorum of 88.02% and weighted segment approval of 96.04%. The interpretation will be presented to the NERC Board of Trustees for adoption in February 2012 and if adopted, filed with regulators for approval.

Background:
Progress Energy asked if Electronic Security Perimeter wiring external to a Physical Security Perimeter must be protected within a six-wall boundary.

Draft	Action	Dates	Results	Consideration of Comments
Interpretation of CIP-006-x R1 for Progress Energy Draft Interpretation Clean(21) | Redline to Last Posting(22) **Supporting Materials:** CIP-006-3C(23)	Recirculation Ballot Info(24) Vote>>	12/09/11 - 12/19/11 (closed)	Summary(25) Full Record(26)	
Interpretation of CIP-006-x R1 for Progress Energy Draft Interpretation Clean(13) | Redline to Last Posting(14) **Supporting Materials:** Unofficial Comment Form(15) CIP-006-3C(16)	Successive Ballot Vote>>	11/11/11 - 11/21/11 (closed)	Summary(18) Full Record(19)	
	Formal Comment Period Info(17) Submit Comments>>	10/12/11 - 11/21/11 (closed)		Consideration of Comments(20)
	Join	10/12/11 -		

	Ballot Pool>>	11/10/11 (closed)		
Progress Energy CIP-006-1, Requirement R1.1 - Automatic Generation Control Revised Interpretation(6) Request for Interpretation(7)	Initial Ballot Info(8) | Vote>>	09/30/09 – 10/12/09 (closed)	Summary(10) Full Record(11)	Consideration of Comments(12)
	Pre-ballot Review Info(9) | Join>>	08/31/09 – 09/30/09 (closed)		
Progress Energy CIP-006-1, Requirement R1.1 - Automatic Generation Control Interpretation(1) Request for Interpretation(2)	Initial Ballot Vote>>	08/07/08 – 08/16/08 (closed)	Full Record(4)	Consideration of Comments(5)
	Pre-ballot Window Info(3) | Join>>	07/08/08 – 08/07/08 (closed)		
To download a file click on the file using your right mouse button, then save it to your computer in a directory of your choice.				

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:
Progress Energy requests a formal interpretation of CIP-006-1Requirement R1.1.

In CIP-006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

- *R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,*
- *R3.2. The Cyber Asset uses a routable protocol within a control center; or,*
- *R3.3. The Cyber Asset is dial-up accessible.*

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets

R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The following interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the Cyber Security Order 706 SAR Drafting Team on July 2, 2008:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter**.** Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Response: The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures.

From: Crews, David [mailto:david.crews@pgnmail.com]
Sent: Wednesday, April 02, 2008 5:05 PM
To: Gerry Adamski
Cc: Woods, Bruce; Goff, Edwin
Subject: Request for Interpretation CIP Standard

Progress Energy requests a formal interpretation of **CIP-006-1.** R1.1.

In **CIP_006-1**, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In **CIP-005-1,** Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In **CIP-002-1,** Requirement 3 states **"**Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

> **R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
>
> **R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
>
> **R3.3.** The Cyber Asset is dial-up accessible.

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Ballot Pool Opens for Interpretation

Now available at: http://www.nerc.com/~filez/standards/Project2008-10_CIP-006_RFI_Progress.html

Pre-ballot Window and Ballot Pool for Interpretation of CIP-006-1 Requirement R1.1 for Progress Energy

Progress Energy submitted a Request for an Interpretation of Requirement R1.1 in CIP-006-1 — Physical Security of Critical Cyber Assets. The request asked if electronic security perimeter wiring external to a physical security perimeter must be protected within a six-wall boundary.

The Interpretation clarifies that the definition of a cyber asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the electronic security perimeter and the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EDT) Thursday, August 7, 2008. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp-RFI_CIP-006_Progress_in@nerc.com

Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Ballot Results	
Ballot Name:	Request for Interpretation - CIP-006-1 - Progress Energy_in
Ballot Period:	8/7/2008 - 8/16/2008
Ballot Type:	Initial
Total # Votes:	194
Total Ballot Pool:	220
Quorum:	**88.18 % The Quorum has been reached**
Weighted Segment Vote:	21.52 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			#	Fraction	#	Fraction	#	
1 - Segment 1.	63	1	10	0.196	41	0.804	4	8
2 - Segment 2.	9	0.7	0	0	7	0.7	0	2
3 - Segment 3.	53	1	9	0.209	34	0.791	5	5
4 - Segment 4.	11	1	2	0.2	8	0.8	0	1
5 - Segment 5.	42	1	11	0.306	25	0.694	2	4
6 - Segment 6.	22	1	5	0.238	16	0.762	0	1
7 - Segment 7.	1	0	0	0	0	0	0	1
8 - Segment 8.	4	0.3	2	0.2	1	0.1	0	1
9 - Segment 9.	6	0.5	1	0.1	4	0.4	0	1
10 - Segment 10.	9	0.7	1	0.1	6	0.6	0	2
Totals	**220**	**7.2**	**41**	**1.549**	**142**	**5.651**	**11**	**26**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Negative	View
1	Ameren Services Company	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott Kinney	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Negative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy	Paul Rocha	Negative	

1	Central Maine Power Company	Brian Conroy		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Consolidated Edison Co. of New York	Edwin Thompson	Negative	View
1	Dominion Virginia Power	William L. Thompson	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	E.ON U.S. LLC	Larry Monday	Negative	
1	East Kentucky Power Coop.	George S. Carruba		
1	Entergy Corporation	George R. Bartlett		
1	FirstEnergy Energy Delivery	Robert Martinko	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	C. Martin Mennes	Negative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Idaho Power Company	Ronald D. Schellberg		
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Abstain	
1	National Grid	Michael J Ranalli	Negative	View
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Negative	View
1	New York Power Authority	Ralph Rufrano	Negative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Negative	
1	Northeast Utilities	David H. Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	View
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Lawrence R. Larson	Negative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Negative	View
1	PacifiCorp	Robert Williams	Negative	View
1	Potomac Electric Power Co.	Richard J. Kafka	Negative	View
1	PP&L, Inc.	Ray Mammarella	Negative	View
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Negative	View
1	Sacramento Municipal Utility District	Dilip Mahendra		
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Christopher M. Turner	Negative	View

1	Sierra Pacific Power Co.	Richard Salgo	Negative	View
1	Southern California Edison Co.	Dana Cabbell	Negative	View
1	Southern Company Services, Inc.	Horace Stephen Williamson	Negative	View
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Negative	View
1	Tampa Electric Co.	Thomas J. Szelistowski	Negative	View
1	Tennessee Valley Authority	Larry Akens	Negative	
1	Tucson Electric Power Co.	Ronald P. Belval	Negative	View
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Robert Temple	Negative	View
1	Xcel Energy, Inc.	Gregory L. Pieper	Negative	View
2	British Columbia Transmission Corporation	Phil Park	Negative	View
2	California ISO	David Hawkins	Negative	View
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Negative	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Terry Bilke	Negative	View
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Negative	View
3	Alabama Power Company	Robin Hurst	Negative	View
3	Allegheny Power	Bob Reeping		
3	Ameren Services Company	Mark Peters		
3	American Electric Power	Raj Rana	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Negative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Cheney	Joe Noland	Abstain	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Negative	View
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Negative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	Farmington Electric Utility System	Alan Glazner		
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Negative	View
3	Florida Municipal Power Agency	Michael Alexander		
3	Florida Power & Light Co.	W.R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Negative	View
3	Grays Harbor PUD	Wesley W Gray	Affirmative	

3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Gwen S Frazier	Negative	View
3	Hydro One Networks, Inc.	Michael D. Penstone	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	View
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	Madison Gas and Electric Co.	Darl Shimko	Negative	View
3	Manitoba Hydro	Ronald Dacombe	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Negative	View
3	New York Power Authority	Christopher Lawrence de Graffenried	Negative	View
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	View
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Negative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Negative	
3	Public Utility District No. 1 of Pend Oreille County	Sandy Hunt	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	View
3	Salt River Project	John T. Underhill	Negative	View
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Tampa Electric Co.	Ronald L. Donahey	Negative	View
3	Tennessee Valley Authority	Cynthia Herron	Negative	
3	Turlock Irrigation District	Casey Hashimoto	Negative	
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	
3	Wisconsin Public Service Corp.	James Maenner	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	View
4	Consumers Energy	David Frank Ronk	Negative	View
4	Florida Municipal Power Agency	Ralph Anderson		
4	LaGen	Richard Comeaux	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Negative	View
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	WPS Resources Corp.	Christopher Plante	Negative	View
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Allegheny Energy Supply Company, LLC	Robert Loy	Negative	View

5	Avista Corp.	Edward F. Groce	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Buckeye Power, Inc.	Kevin Koloini	Abstain	
5	City of Farmington	Clinton J Jacobs	Affirmative	
5	City of Tallahassee	Alan Gale	Negative	View
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	View
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Negative	
5	Constellation Generation Group	Michael F. Gildea	Affirmative	
5	Consumers Energy	James B Lewis	Negative	View
5	Detroit Edison Company	Ronald W. Bauer	Negative	View
5	Dynegy	Greg Mason		
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	Douglas Keegan		
5	Florida Power & Light Co.	Robert A. Birch		
5	Great River Energy	Cynthia E Sulzer	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	View
5	Louisville Gas and Electric Co.	Charlie Martin	Negative	
5	Madison Gas and Electric Co.	Steven Schultz		
5	Manitoba Hydro	Mark Aikens	Negative	View
5	New York Power Authority	Gerald Mannarino	Negative	
5	Northern States Power Co.	Liam Noailles	Negative	View
5	Orlando Utilities Commission	Richard Kinas	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PPL Generation LLC	Mark A. Heimbach	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Negative	View
5	Salt River Project	Glen Reeves	Negative	View
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	David Schiada	Negative	View
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tampa Electric Co.	Frank L Busot	Negative	View
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	Frank D Cuzzort	Negative	View
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Negative	View
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	
6	AEP Marketing	Edward P. Cox	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Dominion Resources, Inc.	Louis S Slade	Negative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Negative	View
6	Florida Municipal Power Agency	Robert C. Williams		

6	Great River Energy	Donna Stephenson	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	View
6	Louisville Gas and Electric Co.	Daryn Barker	Negative	
6	Madison Gas and Electric Co.	Jeffrey M Keebler	Negative	View
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	PP&L, Inc.	Thomas Hyzinski	Negative	View
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	
6	Salt River Project	Mike Hummel	Negative	View
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Southern California Edison Co.	Marcus V Lotto	Negative	View
6	Tampa Electric Co.	Jose Benjamin Quintas	Negative	View
6	Tennessee Valley Authority	Katherine E. York	Negative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
7	Eastman Chemical Company	Lloyd Webb		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Network & Security Technologies	Nicholas Lauriat	Negative	
8	Other	Michehl R. Gent		
8	Volkmann Consulting	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Negative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	Oregon Public Utility Commission	Jerome Murray	Negative	View
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Negative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Negative	View
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Larry Brusseau	Negative	View
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt		
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Negative	View
10	Southwest Power Pool	Charles H. Yeung	Negative	View
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — CIP-006-1 — Progress Energy Request for Interpretation (Project 2008-10)

Summary Consideration: There are five themes that emerged from the industry comments:

1) Wiring does not rely upon or utilize a routable protocol and thus cannot be a cyber asset any more than a power cable is. The NERC definition of cyber asset does not include the language "including the wiring that comprises the physical media supporting the network."

Response: The interpretation response team has reviewed its response and considers the wiring to be a component of the communication network, which is a cyber asset, as defined in the NERC Glossary. As such, the network wiring needs to be protected.

2) This is far too important to resolve via an interpretation. This needs to be addressed in the revisions to the CIP standards and subject to the full stakeholder process.

Response: We agree that this is an important issue, and it will be considered as part of the standards' revision in the Cyber Security Order 706 (CSO706) project (Project 2008-06). However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this request for interpretation (RFI) from Progress Energy.

3) The interpretation exceeds the process rules by changing the requirements of standard, adds concepts not consistent with other NERC guidance, speculates on the intent of the standard, and adds confusion and ambiguity with respect to compliance. It also opens the door for other non-physical "alternatives" to compliance with the requirements of CIP-006.

Response: While the drafting team disagrees it altered any requirements to the standard via the interpretation, the team acknowledges a lack of clarity regarding alternative measures. In drafting the revised interpretation, the team interprets the phrase "alternative measures" to include use of combined/complementary physical and logical approaches to achieve the same or better protection for Electronic Security Perimeter (ESP) wiring that is external to the Physical Security Perimeter (PSP).

4) The wire is not within the ESP; therefore it does not need to be protected. The wire is nothing more than a communication link specifically excluded by CIP-005, R1.3.

Response: The request clearly asked about wiring within an ESP.

5) The cost (dollars, time) to protect wiring in a campus setting far exceeds the benefit derived by doing so. The challenges of having to comply with all of the CIP-006 requirements are an impossible and unreasonable task. The decision to protect wiring should be based upon a proper risk determination process.

Response: The interpretation response team attempted to offer alternative methods for compliance without undue financial burden in the initial interpretation response. In drafting the revised interpretation, the team interprets the phrase "alternative measures" to include use of combined/complementary physical and logical approaches to achieve the same or better protection.

Entity	Segment	Vote	Comment
Allegheny Power	1	Negative	Allegheny Energy is concerned with the SAR drafting team interpretation that wiring within an ESP be considered a Cyber Asset or Critical Cyber Asset. Allegheny Energy agrees that the wiring (and information

Entity	Segment	Vote	Comment
			transmitted by such wiring) within an ESP needs to be protected; however, Allegheny Energy does not agree that the wiring needs to be classified and protected as a defined cyber asset. NERC defines cyber assets as programmable electronic devices and communication networks including hardware, software, and data and does not include the language “including the wiring that comprises the physical media supporting the network”. Allegheny Energy believes the best method to determine protection measures for the wiring (and information transmitted by such wiring) is to create a holistic approach to communication network and data communication link protection through the Standards process that specifically addresses these issues. This new Standard could address communication network and data communication link security issues, including copper cabling, fiber optic cabling, and wireless implementations. By the interpretation stating that network wiring is a cyber asset or potentially a critical cyber asset in an effort to physically secure the wiring, this statement would additionally impose all of the requirements of the CIP standard that are applicable to cyber assets and in essence make entities non-compliant since many requirements cannot be accomplished for wiring.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. For ESP wiring that is external to the PSP: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or monitoring to detect unauthorized access or physical tampering. The RFI response drafting team agrees that this is an important issue and it will be considered as part of the standards’ revision in the Cyber Security Order 706 (CSO706) project.			
Ameren Services Company	1	Negative	We do not agree with this interpretation. We feel that the language in the first sentence of the response, "including the wiring that comprises the physical media supporting the network," could be viewed to include aspects that are not covered in the CIP 002 - 009. Broad interpretation of the response would significantly impact the compliance burden. In addition, CIP 006 R1.1 states: "Where a completely enclosed (six-wall) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." This interpretation does not make it clear whether or not that part of the CIP-006 requirement 006 is still valid, and seems to supersede the CIP standard in this regard.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within			

Entity	Segment	Vote	Comment
an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
American Electric Power	1	Negative	Physical protection (given the relatively controlled locations of some of the data paths in question) should be determined by a risk-based assessment. This would be particularly focused on the likelihood of intrusion given the overall physical environment and other factors (cables buried, guard forces, monitoring cameras, etc.), some of which may qualify as acceptable alternative measures. We believe that this topic should be addressed during the formal development of the next iteration of CIP standards to clarify requirements and include risk factors and a rational, realistic approach. For example, securing a facility housing coal handling systems makes complete sense from a potential intrusion perspective. This is less the case with the cabling running externally from the facility to the control room, often buried and not easily or in obtrusively accessible. Because of the factor listed above, AEP is casting a negative vote for this interpretation. We would prefer that it be addressed fully during the development of the next set of NERC CIP standards.
Response: The RFI response drafting team agrees that this is an important issue and it is presently being considered as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A methodology for determining the appropriate protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Associated Electric	1	Negative	Wiring meets none of the requirements of CIP-002-R3, the wiring does not communicate itself with anything, it is merely a communications conduit or channel, therefore the standard does not apply to it anymore than it

Entity	Segment	Vote	Comment
Cooperative, Inc.			would apply to the ac power wiring. While it is appropriate to protect access to all wiring inside the ESP, I do not believe that the intent of the standard is to consider wiring a CCA and subject it to all of the CIP requirements, many of which can not even be implemented or do not apply. These points were presented very well (and I am in complete agreement with) in the document by Mr. Tim Conway of NiSource, “Wiring as a CCA”.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Brazos Electric Power Cooperative, Inc.	1	Negative	Further clarity should be added to the last sentence to address the interpretation request as follows: Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures as it extends from the ESP up to the Physical Security Perimeter. Then there is the question about what is defined as "tampering".
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering. The RFI response drafting team views tampering to include, but is not limited to, unauthorized access, disruption, or alteration.			
Consolidated Edison Co. of New York	1	Negative	The interpretation is not clear and may modify the intention of the Standard, in our opinion, and needs more work. The existing Standard requirement clearly states, "...all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.

Entity	Segment	Vote	Comment
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
FirstEnergy Energy Delivery	1	Negative	FE thanks the SAR team for their efforts in developing an interpretation for CIP-006-1 Req. R1.1 in response to Progress Energy's request. However, we have cast a Negative vote for the following reasons and ask the team to consider our comments and suggested revision. We feel that the proposed interpretation fails to provide the industry with a clear direction related to the question posed by Progress Energy. As stated, the interpretation largely restates the definition of a Cyber Asset contained in the NERC Glossary of Terms, and a re-statement of CIP-006 R1.1. The interpretation states that "The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." However, the actual definition from the NERC Glossary states that "Cyber Assets include programmable electronic devices and communication networks including hardware, software, and data." Further, in the CIP standards development process the communications paths were deliberately excluded from the scope of the Standards, especially third party communication assets. Accordingly, we concur with the aspect of the interpretation that implies that the communications hardware devices and closets that include critical cyber assets should be secured inside the PSP, but that the physical utility-owned wiring should not be classified as Cyber Asset as the interpretation indicates. This would be consistent with the explicit exclusion of the third party communication assets embodied within the standards. We agree that the definition includes the data as a Cyber Asset, but do not agree that the definition includes the physical wiring as a Cyber Asset. Accordingly as a potential modification to the interpretation, we suggest a revision to the interpretation as follows: "The definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team asserts that physical media (wiring) is a component of a communication network within an ESP and shall be secured inside the Physical Security Perimeter. The communication assets excluded from the standards are the Cyber Assets associated with communication networks and data communication links between			

Entity	Segment	Vote	Comment
discrete ESPs. There is no explicit reference within the standards to third-party communications. The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Hydro One Networks, Inc.	1	Negative	Hydro One Networks Inc. is casting a Negative vote with the following comment: The interpretation is not clear and may modify the intention of the Standard. It needs more work. The existing Standard requirement clearly states, "...all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter," which must be protected. While the wires connecting two ESPs need to be protected it should not make one PSP of both. Appropriate conduit or similar protection as appropriate should be acceptable.
Response: The equipment configuration described in this comment wherein two physically separate Cyber Assets that are individually classified as having its own ESP would indeed not require physical access protection for the interconnecting wiring. However, the situation as described by the requestor is different. The configuration indicated by the requestor involves physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.			
Manitoba Hydro	1	Negative	Manitoba Hydro agrees with the part of the interpretation provided by the SAR drafting team that protection of the data transmitted over wires within an Electronic Security Perimeter as the intent of the requirement. This provides more flexibility to meet the standard by allowing not only physical protection of the wire, but also alternative protective measures for the data such as encryption. Responsible Entities should take reasonable measures to protect the data within an Electronic Security Perimeter. However, Manitoba Hydro does not agree with the part of the interpretation provided by the SAR drafting team that “the definition of a Cyber Asset includes both the data and communication networks, including the wiring that comprises the physical media supporting the network.” It should be made clear that the wiring within an Electronic Security Perimeter is considered as part of the Cyber Asset (programmable device or communication network) and that wiring is not itself a Cyber Asset. Since the term communication network is not a NERC defined or clearly understood industry term, the interpretation should not use communication network (or network) as part of any clarifying statement.
Response: The RFI response drafting team agrees and submits a revised RFI response. The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. However, the			

Entity	Segment	Vote	Comment
drafting team disagrees with removal of the term communication network in the RFI response as it is already referenced in the NERC Glossary definition of a Critical Cyber Asset.			
National Grid	1	Negative	The interpretation is not clear and may modify the intention of the Standard. The existing Standard requirement clearly states, "...all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures for ESP wiring that is external to the PSP may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
New Brunswick Power Transmission Corporation	1	Negative	The interpretation is not clear and may modify the intention of the Standard, in our opinion, and needs more work. The existing Standard requirement clearly states, "…all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Orange and Rockland Utilities, Inc.	1	Negative	Orange and Rockland cannot support CIP-006 R1.1 and requests further clarification of "alternative protection measures" encompassing the wiring that comprises the "physical media" supporting the network.
Response: The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures for ESP wiring that is external to the PSP may include, but are not			

Entity	Segment	Vote	Comment
limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
Pacific Gas and Electric Company	1	Negative	As written the interpretation is too broad. The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within the pertinent parts of a given facility or campus.
Response: The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border: alternative physical control measures for ESP wiring that is external to the PSP may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.			
PacifiCorp	1	Negative	"The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus." "If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances."
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets "alternative measures" for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection. CIP-006 R1.1 states: "Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering. The drafting team believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected not to include such language.			
Potomac Electric	1	Negative	Pepco is a subsidiary of PHI. PHI feels that the interpretation is not clear and the response itself is subject to interpretation. This lack of clarity is the basis for PHI's rejection. PHI also believes that communication systems

Entity	Segment	Vote	Comment
Power Co.			should be protected. The Answer to Question 11 of the FAQ associated with these standards states that communication systems are not covered by these standards.

Response:

The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The asset owner is encouraged to reconsider the design of a communication network that extends the ESP across third-party communications systems and networks.

The RFI response drafting team interprets “alternative measures” for ESP wiring that is external to the PSP to include use of a combined/complementary physical or logical approach to achieve the same or better protection.

CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures for ESP wiring that is external to the PSP may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.

Question 11 of the FAQ for standard CIP-002-1 – Cyber Security – Critical Cyber Assets (reproduced below) refers to Section A 4.2.2 regarding the exclusion of Cyber Assets associated with communication networks and data communication links between discrete ESPs. Communications within the ESP are covered by these standards.

CIP-006-1 The asset owner is encouraged to reconsider the design of a communication network that extends the ESP across third-party communications systems and networks.

11. FAQ - Question: *Do communication-related Cyber Assets for Critical Cyber Assets require protection under the Cyber Security Standards?*

Answer: Communications is not covered under this standard because communications are often leased by the Responsible Entities and the technologies for existing Cyber Assets do not always support encryption or other possible security alternatives. Asset owners are encouraged, whenever possible, to provide communications or communication systems with the same protection as their associated Critical Cyber Asset.

PP&L, Inc.	1	Negative	The definition of a Cyber Asset includes both the data and the routable protocol-based communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures. Alternative protection measures could include 24 x7 monitoring, alerting, and logging of attempts at or actual compromise of the network. Supporting information: Based on CIP-002, R3, the definition introduced by the Interpretation should be limited to the "routable protocol-based" communication networks associated with Cyber Assets.

Response:

The RFI response team agrees with the comment that the objective is to protect the data. To do so requires measures to prevent tampering of Cyber Assets. However, the RFI response team disagrees with the last point. The drafting team asserts that the requirement R1.1 does not limit application of alternative measures only to “routable protocol-based communication networks” and therefore doing so is unjustified.

Entity	Segment	Vote	Comment
Puget Sound Energy, Inc.	1	Negative	Definition of Cyber Asset: We do not believe the existing definition of "Cyber Asset" should include wiring. From the most recent (February 12, 2008) NERC "Glossary of Terms Used in Reliability Standards": "Cyber Assets - Programmable electronic devices and communication networks including hardware, software, and data." Wires are not programmable, are not software, and are not data. While they are physical media, it is highly questionable if they could be considered hardware as our understanding is that hardware devices are what software runs on. If we were to extend the definition to include a wire strictly because it carries data, at what point do we consider a telephone pole a Cyber Asset because it carries wires which carry data? If the definition does include wiring, how then do wireless communications media fit into the definition in the context of physical protection of Cyber Assets? Wireless is neither hardware, software, or data and, with regards to this interpretation, physical protection of airborne electrons is not practical/possible with today's technology. Alternative Protective Measures: As most facilities which house Critical Cyber Assets were constructed prior to the CIP standard adoption by FERC, many such facilities have a common wiring infrastructure for both Critical Cyber Assets and assets that are not in scope for CIP compliance. We believe it is unreasonable to require every wire be traced and extracted from common conduit, cable bundles, or other common pathway for the purposes of re-enclosing them in a CIP-specific conduit or other “six-wall” perimeter. The very act of performing this work will introduce an increased reliability risk. If wiring is to be included in the definition of Cyber Asset, we feel that a “completely enclosed (“six-wall”) border” cannot be established for most wiring infrastructures given the above. Therefore, the "alternative measures to control physical access to the Critical Cyber Assets" phrase from CIP-006 R1.1 must be used. The definition for Critical Cyber Assets require that a Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or, the Cyber Asset uses a routable protocol within a control center; or, the Cyber Asset is dial-up accessible, and wiring has no such attributes. Given that CIP-006 R1.1 talks about both Cyber Assets and Critical Cyber Assets, can the interpretation team comment on the above? We would also like clarification on whether "alternative protective measures" includes situations that only deploy purely logical controls of data transiting the wire. As the interpretation team has stated, “The intent is to protect the data transmitted over the network within the ESP”, would an ESP that spans an entity’s entire infrastructure and only employs logical “alternative protective measures”, be an acceptable response to this interpretation? Summary: We commend the interpretation team for wanting to address data in motion, but the appropriate venue to address this issue is NERC Project 2008-06 as CIP-006 R1.1 prescribes requirements for physical protection of Cyber Assets (or just Critical Cyber Assets when a “six-wall” perimeter cannot be established) within an ESP. Additionally, based on our assessment of the term Cyber Asset, we believe requirements to protect communications media are beyond the scope of the existing CIPs. Outstanding RFI How does the Project 2008-10 interpretation for Progress Energy relate to the previous interpretation request (below) from October 10, 2007 by Puget Sound Energy? --- 1) We are requesting an interpretation of the term “externally connected” as used in 005.R1.1. Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s) We request an interpretation which allows encrypted connections over frame relay within a single ESP. Note in the diagram above the routers are not considered “access points” to the ESP, but rather are contained within it. 2) We are requesting clarification of CIP-006-1 R1.1: Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely

Entity	Segment	Vote	Comment
			enclosed ("six wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets. The standard does not explicitly require a given ESP to be fully contained by a single PSP. We request a clarifying interpretation which allows an ESP to span multiple PSPs provided that communications within the ESP are protected sufficiently to prevent unauthorized access. Commentary: With the use of encrypted tunnels and physical protection of the tunnel endpoints, we believe that secure, CIPS compliant ESPs can be designed which span multiple PSPs. It should be noted that 005.R1.3 defines communication links between ESPs as an "access point", which in turn requires port/protocol restrictions at the access point (005.R2.2). However, OSI layer 3 controls won't solve what is fundamentally an OSI layer 2 concern. Specifically, port and protocol restrictions at the endpoints of a frame relay connection will not adequately mitigate the risk of exposure to packets being manipulated at OSI Layer 2. Hence, our desire to use encrypted tunnels to assure packet integrity and source authenticity thereby addressing the layer 2 concerns. Thank you for the opportunity to comment.
Response: The RFI response team agrees with the comment that the main objective is to protect the data. To do so requires measures to prevent tampering of Cyber Assets. In regard to wiring, the RFI response drafting team asserts that the definition of Cyber Asset in the NERC Glossary indeed includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets "alternative measures" to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. With respect to the commentary about a single ESP spanning multiple PSPs, the specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside the ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 applies. The drafting team is not familiar with the October 10, 2007 RFI by Puget Sound Energy.			
Salt River Project	1	Negative	In cases where the building hosting the Critical Asset is under control of the Registered Entity, the building itself should serve as the six sided physical container. The possibility of an employee, contractor or guest pulling up a floor panel or ceiling tile, finding the right cable or fiber, and then having a way to tap or monitor the line is not a credible threat.
Response:			

Entity	Segment	Vote	Comment
The building hosting the Critical Asset, when under the control of the Responsible Entity, is a qualified Physical Security Perimeter only when access is controlled per CIP-006-1 and all personnel with unescorted access have met the applicable requirements of the CIP standards, including completion of personnel risk assessments and training. If the entire building is not a qualified PSP, then alternative measures must be applied to protect wiring not enclosed within the qualified PSP(s) within the building.			
Seattle City Light	1	Negative	The reasoning for this vote is as follows: As noted in the Progress Energy submittal to NERC, they have cited the requirements for Critical Cyber Assets (CCAs) to be contained within the Electronic Security Perimeter (ESP) and for the ESP to be contained within the Physical Security Perimeter. However, a scenario can easily develop whereby CCA's are connected via cable/wiring and the affected wiring runs outside of the ESP and sometimes outside of the Physical Security Perimeter. In some instances the wiring could be underground, in cable trays, and even via poles and towers. Therefore, the key issue to recognize is that the cables/wires may be in circumstances whereby complete encapsulation (i.e., to achieve the "6-sided wall" mandate) would be extraordinarily expensive, extremely difficult, and in many cases not add any added physical protection due to the location of the wire/cable and distance away from unauthorized tampering. Also, if the cables are still within the physical security perimeter but outside the ESP, then added protection is not necessarily value added from a security standpoint because physical access is still afforded but not accepted in the interpretation. Our recommendation is that the interpretation take into account the security buffer between the Electronic Security Boundary and the Physical Security Boundary for cables/wires. Secondly, it is also recommended that protection of the data is paramount and that some logical controls should be taken into account for data protection even though the cable may be external to the ESP. Thirdly, encapsulating cable with conduit, cages or other "6-sided wall" protective measures may not be reasonable for the security value add and that the interpretation should take into account the physical location of the wires/cables that prevent an unauthorized party from tampering with the physical layer of the equipment.

Response:

The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.

The scenario described in this comment wherein two physically separate Cyber Assets that are individually classified as each having its own ESP would indeed not require physical access protection for the connective wiring.

The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. These measures can account for data protection.

The recommendation to address data in motion is currently included in the work of the CSO706 Project.

Entity	Segment	Vote	Comment
Sierra Pacific Power Co.	1	Negative	This interpretation seems to expand the applicability of the CIP Requirements outside the bounds of the Critical Assets.
Response: The RFI response drafting team does not expand the applicability of the CIP requirements but states the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset.			
Southern California Edison Co.	1	Negative	Southern California Edison Company (SCE) SCE appreciates the opportunity to provide comments on the NERC Standards Development team's proposed interpretation for CIP-006-1's Requirement 1.1 ("Proposed Interpretation"). SCE cast a negative vote on the Proposed Interpretation because it causes additional confusion and could result in unreasonable and impractical consequences that would not improve the security of the Cyber Assets or the Electronic Security Perimeter. SCE believes issues identified by Progress Energy should be addressed during the review of CIP-006 scheduled to take place in 2009. Supporting reasons for this position are provided below. The proposed interpretation states that "Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." SCE shares a concern raised by WECC in their position paper that if the physical media used to transport critical data is considered a Critical Cyber Asset, then it would require all of the requisite physical protections specified in the existing CIP standards. SCE feels physical media supporting the network cannot be subject to the physical protections specified in CIP standards. For example, if a network cable runs from a Critical Cyber Asset situated within an identified Physical Security Perimeter to a point or through any area that is outside the identified Physical Security Perimeter, it is not clear that taking measures to protect the cable from tampering, and potentially having to monitor access to the cable, would be an appropriate way to secure the network. Access to SCE's communications network, and the data which streams across it, is strictly controlled by an Electronic Security Perimeter which personnel and equipment/ application(s) are given narrow access rites dependent on their usage requirements. The allowance of "alternative protective measures" for physical media supporting the network is also not clearly defined, and could even be interpreted to allow for logical protections without physical protection of Cyber Assets. This clearly would not be an appropriate outcome as pointed out in WECC's position paper as well. The uncertainty created by the interpretation's reference to alternative protective measures is another reason SCE voted against the interpretation. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances. In closing, it is SCE's opinion that the Proposed Interpretation and the issues brought-up in relation to the actual definition of Cyber Asset be fully addressed and incorporated into the revised CIP-006 standard. Pursuant to NERC's Reliability Standards Development Plan an effort to revise the CIP standards will be initiated in 2009.
Response: The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that			

Entity	Segment	Vote	Comment
is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, the request from Progress Energy must be addressed in the formal Interpretation process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The drafting team recognizes there are instances that pose technical and/or costly challenges to protection of Cyber Assets and clarifies that the current requirement includes the use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. To the commenter's point regarding more prescriptive and specific language, the drafting team believes that it could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Southern Company Services, Inc.	1	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. - The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The phrase "alternative measures" in the Requirement R1.1 of CIP-006-2 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
Southwest Transmission Cooperative, Inc.	1	Negative	"The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus." "If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances."
Response:			

Entity	Segment	Vote	Comment
The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team believes alternative measures is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible.			
Tampa Electric Co.	1	Negative	Tampa Electric Company’s Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry’s attention and attempting to clarify this issue. Tampa Electric Company has several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach may be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security “ such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: ? These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. ? The primary DCS vendors in our environment have stated to us that they do not offer or support an approved mechanism for firewalling within the DCS network or encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. ? The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, Tampa Electric recommends that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations . We believe that the Standard Authorization Request should be modified to address concerns and issues related to: ? Unauthorized access to the ESP through access to physical cabling. ? Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. ? Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.

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Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets “alternative measures” to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Tennessee Valley Authority	1	Negative	While we agree that physical and electronic perimeters must be the same or the data must protected as it traverses physical perimeters, TVA doesn't think that the interpretation provides sufficient detail to guide compliance.
Response: The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. The RFI response drafting team is limited in its ability to provide more explicit guidance and believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Tucson Electric Power Co.	1	Negative	TEP supports the following provided by WECC: "The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus." "If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances."
Response: The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to			

Entity	Segment	Vote	Comment
avoid such language.			
Westar Energy	1	Negative	Disagree with the concept that wire is a Cyber Asset.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset.			
Western Area Power Administration	1	Negative	The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to "wires within a given facility or campus" and therefore doing so is unjustified. The drafting team has clarified what it interprets "alternative measures" to mean in the revised response and believes the phrase "alternative measures" is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Xcel Energy, Inc.	1	Negative	While Xcel Energy generally supports what we understand to be the intent of the interpretation, we feel it is not clear and could create further ambiguity. An interpretation should be clear and not create further room for interpretation. As explained to us by a member of the Cyber Security Order 706 SAR Drafting Team, the interpretation is designed to address the situation where there are potentially two separate physical security perimeters (PSP) with assets that are part of the same ESP -- such as two separate rooms, a data center and an operations center, that both have critical cyber assets and individual physical security perimeters. You could still have one ESP for the single building -- however, since the wiring connecting the assets in each of these rooms leaves the physical security perimeters, you need to protect the wiring with a physical boundary (conduit), or encrypt the data. We feel strongly that this interpretation, as written, could be implemented and/or enforced inconsistent with what the drafting team intended, and recommend a new draft of the interpretation, including a diagram, be developed. Also, since this interpretation will likely have a substantial impact on

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			entities, an implementation plan should be considered.
Response: The RFI response drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope. The team understands the desire for more specificity and prescription such as in a diagram but believes that could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
British Columbia Transmission Corporation	2	Negative	The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of “alternative protective measures” is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: The RFI response team asserts that requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
California ISO	2	Negative	The interpretation adds requirements that are not already part of the standard. CIP-006-1 describes the requirements for physical access controls. An interpretation of a standard should not be confused with “what should have been done”. The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including explicit reference to data in transit over communications links between discrete perimeters, the interpretation moves into an area which the standard intentionally does not address. Conflicts: the interpretation crosses multiple standards CIP-006-1, R1.1 "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." CIP-005-1, R1.3: "Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s)."

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			Glossary: "Cyber Assets: Programmable electronic devices and communication networks including hardware, software, and data." The reference in CIP-005, R1.3 describes "communication links"; in reality, those links are the "wiring" that the interpretation request is describing; thus, they are not within the Electronic Security Perimeter and do not need to be within a Physical Security perimeter.
Response: The RFI response drafting team recognizes that while data in transit is fundamentally the asset to be protected, it agrees that the CSO706 Project is where it should be addressed. Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
Independent Electricity System Operator	2	Negative	Although directionally the IESO is in favour of the intent of the interpretation, we believe the current interpretation wording may effectively modify the intention of the standard, which is inconsistent with NERC standard development protocol, and hence the interpretation needs more work. CIP-006-1, R1.1 states: "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures TO CONTROL PHYSICAL ACCESS(emphasis added) to the Critical Cyber Assets." the interpretation states: The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring OR ALTERNATIVE PROTECTIVE MEASURES(emphasis added). Whereas the standard clearly requires physical access control, the interpretation effectively relaxes this requirement with the words either through physical protection of the wiring or alternate protective measures where the resultant implication is that the alternate protective measures are non-physical, hence a relaxation of the standard. Although we believe the standard should be revised to allow alternative protective measures, that is not the issue being balloted.
Response: The RFI response drafting team respectfully disagrees that the scope of alternative measures does not include logical approaches. The drafting team concurs that the intent is to protect the data that travels over the wiring and asserts that either physical or logical measures are capable of achieving the desired objective.			
ISO New England, Inc.	2	Negative	There are three significant issues with this Interpretation which resulted in a negative vote: (1) the interpretation adds requirements that are not already part of the Standard, the Standard intentionally did not originally address data in transit over communication links; (2)the interpretation creates conflicts between CIP-006 R1.1 and CIP-005, R1.3, which clearly states that communication links connecting discrete ESPs shall not be considered part of the ESP; and (3) we believe that the current Standard is clear enough and this interpretation simply creates more confusion in the industry, we have not had any problems in understanding or implementing

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			the Requirements in this Standard.
Response: (1) The notion of data in transit, while at the core of the protection purpose, is more appropriately addressed in the ongoing CSO706 Project. This interpretation does not add a requirement to protect communication links, or the data transiting thereon, that are outside of the ESP. (2) Although the drafting team is limited to respond to this request from Progress Energy, to the point about "communication links" cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP. (3) The drafting team is compelled by process to respond to this RFI from Progress Energy.			
Midwest ISO, Inc.	2	Negative	The FAQ developed along with the original CIP standards specifically state that the standards are not intended to address the wires between facilities. While we agree that the suggested interpretation is a good idea for a future improvement to the standard, the interpretation process is intended to clarify what the standard says as originally drafted, not what we would like the standard to say.
Response: The FAQ is a guidance document and is not mandatory and enforceable as NERC standards are. However, question #11 (reproduced below) refers to assets that are not owned by the Responsible Entity, such as third party telecommunications company equipment. This interpretation does not add a requirement to protect communication links, or the data transiting thereon, that are outside of the ESP. In this instance, the wiring referenced by Progress Energy is clearly within a single ESP. **11. FAQ - Question:** *Do communication-related Cyber Assets for Critical Cyber Assets require protection under the Cyber Security Standards?* **Answer:** Communications is not covered under this standard because communications are often leased by the Responsible Entities and the technologies for existing Cyber Assets do not always support encryption or other possible security alternatives. Asset owners are encouraged, whenever possible, to provide communications or communication systems with the same protection as their associated Critical Cyber Asset.			
PJM Interconnection, L.L.C.	2	Negative	PJM has the following concerns: Procedural: the interpretation adds requirements that are not already part of the standard. CIP-006-1 describes the requirements for physical access controls. An interpretation of a standard should not be confused with "what should have been done". The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including an explicit reference to data in transit over communications links between discrete perimeters, the interpretation moves into an area which the standard intentionally does not address. Conflicts: the interpretation crosses multiple standards CIP-006-1, R1.1 "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." CIP-005-1, R1.3: "Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s)." Glossary: "Cyber Assets: Programmable

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			electronic devices and communication networks including hardware, software, and data." The reference in CIP-005, R1.3 describes "communication links"; in reality, those links are the "wiring" that the interpretation request is describing; thus, they are not within the Electronic Security Perimeter and do not need to be within a Physical Security perimeter. Necessity: the definitions and descriptions contained within the published standard seem clear; the issue has posed no significant problems for SWG member organizations to understand or implement.
Response: The RFI response drafting team recognizes that while data in transit is fundamentally the asset to be protected, it agrees that the CSO706 Project is where it should be addressed. This interpretation does not add a requirement to protect communication links, or the data transiting thereon, that are outside of the ESP. The definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
Alabama Power Company	3	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. - The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The phrase “alternative measures” in the Requirement R1.1 of CIP-006-2 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
American Electric Power	3	Negative	Although we agree that a true "systems" approach to data protection would also include the data paths, we are concerned about an element that we believe should be included in any determination of communication path physical security. Physical protection (given the relatively controlled locations of some of the data paths in question) should be determined by a risk-based assessment. This would be particularly focused on the likelihood of intrusion given the overall physical environment and other factors (cables buried, guard forces, monitoring cameras, etc.), some of which may qualify as acceptable alternative measures. We believe that this topic should be addressed during the formal development of the next iteration of CIP standards to clarify requirements and include risk factors and a rational, realistic approach. For example, securing a facility housing coal handling systems makes complete sense from a potential intrusion perspective. This is less the case with the cabling running externally from the facility to the control room, often buried and not easily or in obtrusively

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			accessible. Because of the factor listed above, AEP is casting a negative vote for this interpretation. We would prefer that it be addressed fully during the development of the next set of NERC CIP standards.
Response: The RFI response drafting team agrees that this is an important issue and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Consolidated Edison Co. of New York	3	Negative	The interpretation is not clear, may modify the intention of the Standard, and needs more work. The existing Standard requirement clearly states, "..all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Consumers Energy	3	Negative	Consumers Energy’s understanding of the requirements of CIPS-005-1 and CIPS-006-1 as they were being developed and as they exist today allowed for discrete non-contiguous physical security perimeters to protect cyber assets contained within a single electronic security perimeter, presumably by excluding the communication network and data passing over the communication network as being defined as Cyber Assets requiring physical protection. We believe that this view is consistent with good utility practice utilized at a number of North America’s control centers and generating plants. In extending the definition of Cyber Asset to include data and the communication network, the Interpretation clearly goes beyond the scope intended by the original drafters of the Standards. CIP-002-1 R3, Critical Cyber Asset Identification, refers to several examples of possible Critical Cyber Assets, all of which can be considered computer systems or devices possessing a central processing unit. Seven of the nine requirements in CIP-007-1 refer to Cyber Assets and clearly are intended to apply to computer systems, and none of the nine requirements specifically address network cables or data. Had the original intent of the standards been to include the communication networks within an electronic security perimeter as Cyber Assets requiring physical protection we would have expected the standard to address appropriate protection where six-wall physical protection (complete with access control

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			and monitoring) is not necessary (such as with buried portions of the network) or practical (such as within raceways or conduit). Additionally, the time required to re-wire such networks so as to provide six-wall physical protection is significantly longer than the time required to provide six-wall physical protection to the access points to Cyber Assets within the Electronic Security Perimeter. Further, had the original intent of the standards been to include data that passes over the communication network, the standard should have discussed the issues associated with transporting, storing and restoring back-up tapes and other removable media so as to protect cyber assets in the event the back-up data is re-introduced to the electronic security perimeter. We suggest the actual intent of the CIP Standards is to define as a Cyber Asset only those devices with a central processing unit. These are the devices susceptible to remote attack and compromise. We believe the primary intent of the present version of the CIP Standards is to protect against remote compromise of those assets. The apparent intent of the Interpretation, to require all network cabling be protected by a six-wall boundary, goes beyond the intent of the CIP Standards as they were developed and implemented. CIP-006-1 R1.1 states "ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter." This does not require a piece of hardware without a CPU, such as a network cable, to reside within a six-wall boundary. Consumers Energy argues that protecting communication network cabling residing in an area entirely within the reasonable and prudent control of the Responsible Entity is beyond the scope of the present CIP Standards. Had the intent of the requirement been to include all communication network and data as Cyber Assets requiring physical protection, the wording should have stated such. If the apparent intent of the Interpretation, to require network cabling to be contained within a six-wall boundary, is accepted, there will be no distinction between "in-house" cabling and connections carried through public networks. This ignores the different threat exposure of the two types of communication circuits. This Interpretation will divert money and other resources from mitigating higher threat exposures, such as man-in-the-middle attacks on unencrypted external communications circuits, to this lower threat exposure. We propose the following wording to replace the existing interpretation: Response: The Physical Security Perimeter is required to protect the access points to Critical Cyber Assets within the Electronic Security Perimeter. For dedicated communication networks within a discrete Electronic Security Perimeter under the normal reasonable and prudent control of the Responsible Entity, all elements of such network do not require to be contained within the Physical Security Perimeter so long as all access points to the Critical Cyber Assets within the Electronic Security Perimeter are also within a Physical Security Perimeter. CIP-005-1 R1.1 refers to any externally connected communication end point (for example, dial-up modems) as specifically identified as an access point to the Electronic Security Perimeter. The use of "externally connected" in this context refers to communication facilities outside the control of the Responsible Entity. Examples of such connections would include dial-up or leased telephone or data circuits, commercial packet-switched networks, wireless networks, or the Internet. Examples of connections not considered to be "external" would include local area networks between floors in a building or between buildings in a campus environment.
Response: The RFI response drafting team believes the commenter's presumption that protection is not required for wiring between "discrete non-contiguous physical security perimeters" is not justified. The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a			

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single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 justifiably applies. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP. The drafting team believes that the other concerns raised by the commenter, including transfer of backup tapes and other removable media, is best addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project.			
Cowlitz County PUD	3	Negative	Cowlitz County PUD No.1 (District) finds the interpretation does not clarify the intent of the Standard. Extension of the "6-wall" physical security perimeter with conduit would require an accounting for all access points (condulets or conduit bodies) and appropriate access monitoring. Simple use of conduit does not offer the best protection of data as it can be easily compromised. The verbiage "or alternative protective measures" needs clarification - or alternative physical and/or logical protective measures - to protect the original intent of the Standard. The District's position is that logical protective measures (such as loss of continuity alarms) will in many cases better protect data from malicious tampering than physical protective measures.
Response: The RFI response drafting team clarifies CIP-006 R1.1 which states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Duke Energy Carolina	3	Negative	Thank you for the opportunity to vote on this interpretation. We think that the interpretation is unclear. A new NERC Cyber Security drafting team is in the process of being assembled, and Duke Energy believes that this issue is best addressed in a comprehensive manner by the new Cyber Security drafting team. The manner of protecting data from tampering when it is transmitted over networks should be clearly defined in the new Cyber Security Standard, and any newly prescribed protection methods must be properly related to other requirements in the standards where that is appropriate.
Response: The RFI response drafting team agrees that this is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			

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FirstEnergy Solutions	3	Negative	FE thanks the SAR team for their efforts in developing an interpretation for CIP-006-1 Req. R1.1 in response to Progress Energy's request. However, we have cast a Negative vote for the following reasons and ask the team to consider our comments and suggested revision. We feel that the proposed interpretation fails to provide the industry with a clear direction related to the question posed by Progress Energy. As stated, the interpretation largely restates the definition of a Cyber Asset contained in the NERC Glossary of Terms, and a re-statement of CIP-006 R1.1. The interpretation states that "The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." However, the actual definition from the NERC Glossary states that ""Cyber Assets include programmable electronic devices and communication networks including hardware, software, and data." Further, in the CIP standards development process the communications paths were deliberately excluded from the scope of the Standards, especially third party communication assets. Accordingly, we concur with the aspect of the interpretation that implies that the communications hardware devices and closets that include critical cyber assets should be secured inside the PSP, but that the physical utility-owned wiring should not be classified as Cyber Asset as the interpretation indicates. This would be consistent with the explicit exclusion of the third party communication assets embodied within the standards. We agree that the definition includes the data as a Cyber Asset, but do not agree that the definition includes the physical wiring as a Cyber Asset. Accordingly as a potential modification to the interpretation, we suggest a revision to the interpretation as follows: "The definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: The RFI response drafting team asserts that physical media (wiring) is a component of a communication network within an ESP and shall be secured inside the Physical Security Perimeter. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Georgia Power Company	3	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. -

Entity	Segment	Vote	Comment
			The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The RFI response drafting team has clarified that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The phrase “alternative measures” in the Requirement R1.1 of CIP-006-2 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
Gulf Power Company	3	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. - The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The RFI response drafting team has clarified that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The phrase “alternative measures” in the Requirement R1.1 of CIP-006-2 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
Hydro One Networks, Inc.	3	Negative	Hydro One Networks Inc. is casting a Negative vote with the following comment: The interpretation is not clear and may modify the intention of the Standard. It needs more work. The existing Standard requirement clearly states, "..all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter," which must be protected. While the wires connecting two ESPs need to be protected it should not make one PSP of both. Appropriate conduit or similar protection as appropriate should be acceptable.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the			

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connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 justifiably applies. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. Appropriate conduit, as suggested by the commenter, is an acceptable physical protection.			
Lincoln Electric System	3	Affirmative	Any wiring within the electronic security perimeter must be protected by a six-wall physical security perimeter. Wiring external to the electronic security perimeter constitutes a "communications link", and therefore does not need to be protected by the physical security perimeter. It appears that some confusion on this issue stems from the fact that Progress Energy's original question isn't even possible - it pertains to wiring within the electronic security perimeter, but outside the physical security perimeter. According to Requirement 1.1, the electronic security perimeter must be a subset of the physical security perimeter. Therefore, any wiring within the electronic security perimeter must also fall within the physical security perimeter by default.
Response: The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside the ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 applies.			
Madison Gas and Electric Co.	3	Negative	We disagree with the interpretation because it adds language that needs further interpretation and does not address our confusion in the Standard regarding when data traveling over a network needs to be protected and when it does not. The interpretation implies the measures referenced in CIP006, R1.1, focus on preventing physical access that would allow data to be tampered with in transit. Can we assume the focus is not on preventing physical access that allows data to be gathered/inspected, but rather to prevent tampering with the data? If so, would using optical fibers carrying data communication between two physical security perimeters be a sufficient physical control, assuming fiber provides a higher level of security to protect the data from tampering. Do optical fibers contained within a continuous, fully-jacketed cable, the only end points of which are contained within separate six-sided physical security perimeters, meet the requirements of the Standard under this interpretation? If not, what constitutes the physical security perimeter and what constitutes a physical access point? Please provide guidance, including examples, on the "alternative protective measures" that would be acceptable to meet the standard. The standards are confusing because of the explicit exemption under the Introduction section, Item 4.2.2, of each standard that excludes "Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters." We assume "communication networks" and "communication links between discrete ESP's" are two different things, since they are referenced separately in other parts of the Standard. Communication links between discrete ESP's are referenced in CIP-005, R1.3, as being outside of the ESP. This reference does not help to clarify the exemption. In addition, communication networks are not referenced in CIP-005, R1.3, or anywhere else except in the definition of Cyber Assets. To say that communication networks are exempt from the Standard implies the data traveling on those networks are also exempt. If this is incorrect, what is NERC's interpretation of the

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			explicit exemption? From a protection standpoint, if there is a difference between the wire and the data traveling across the wire, that needs to be explicitly defined. Where does the Standard state whether data traveling between ESP's does or does not have to be protected?
Response: The RFI response drafting team agrees that protection of data in motion is an important issue and is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. This request from Progress Energy must be addressed in the formal Interpretation process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team disagrees with the commenter that the exemption in R4.2.2 applies because the specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 indeed applies. In the revised response to Progress Energy, the drafting team interprets alternative measures to include approaches that are physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Manitoba Hydro	3	Negative	Manitoba Hydro agrees with the part of the interpretation provided by the SAR drafting team that protection of the data transmitted over wires within an Electronic Security Perimeter as the intent of the requirement. This provides more flexibility to meet the standard by allowing not only physical protection of the wire, but also alternative protective measures for the data such as encryption. Responsible Entities should take reasonable measures to protect the data within an Electronic Security Perimeter. However, Manitoba Hydro does not agree with the part of the interpretation provided by the SAR drafting team that "the definition of a Cyber Asset includes both the data and communication networks, including the wiring that comprises the physical media supporting the network." It should be made clear that the wiring within an Electronic Security Perimeter is considered as part of the Cyber Asset (programmable device or communication network) and that wiring is not itself a Cyber Asset. Since the term communication network is not a NERC defined or clearly understood industry term, the interpretation should not use communication network (or network) as part of any clarifying statement.
Response: The RFI response drafting team agrees and submits a revised interpretation response stating the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset.			

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However, the drafting team disagrees with removal of the term communication network in the RFI response as it already referenced in the NERC Glossary.			
MidAmerican Energy Co.	3	Negative	MidAmerican Energy believes that this interpretation expands the requirements of the standard inappropriately.
Response: The RFI response drafting team does not expand the meaning of but rather interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Mississippi Power	3	Negative	- The interpretation is not supported in any way by the wording of the standard; it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice. - The interpretation was written by a body, the CIP version 2 SAR drafting team, which was not formed for that purpose and which did not have specific expertise to be able to address the problem. - The interpretation creates a number of unresolved issues by using vague language around alternate measures. - The interpretation creates a situation where a CCA may need to be identified which can only be subject to one of the many requirements in the standards and which makes it difficult to reconcile the status of a cable or wireless CCA with the language of the other standards.
Response: The RFI response drafting team is asked to interpret the wording in a standard. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The phrase “alternative measures” in the Requirement R1.1 of CIP-006-1 is interpreted by the drafting team to include physical and logical protection approaches. The team is comprised of industry subject matter experts in the field of cyber security.			
New York Power Authority	3	Negative	The interpretation is not clear and may modify the intention of the Standard, in our opinion, and needs more work. The existing Standard requirement clearly states, "... all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimieter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a			

Entity	Segment	Vote	Comment
completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Niagara Mohawk (National Grid Company)	3	Negative	The interpretation is not clear and may modify the intention of the Standard and therefore needs more work. The existing Standard requirement clearly states, "..all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimieter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Platte River Power Authority	3	Negative	The interpretation would be acceptable if language is added similar to what is suggested below: The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering. Where (“six-wall”) physical protection of the wiring cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to			

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physical tampering.			
Public Utility District No. 2 of Grant County	3	Affirmative	
Salt River Project	3	Negative	In cases where the building hosting the Critical Asset is under control of the Registered Entity, the building itself should serve as the six sided physical container. The possibility of an employee, contractor or guest pulling up a floor panel or ceiling tile, finding the right cable or fiber, and then having a way to tap or monitor the line is not a credible threat.
Response: The building hosting the Critical Asset, when under the control of the Responsible Entity, is a qualified Physical Security Perimeter only when access is controlled per CIP-006-1 and all personnel with unescorted access have met the applicable requirements of the CIP standards, including completion of personnel risk assessments and training. If the entire building is not a qualified PSP, then alternative measures must be applied to protect wiring not enclosed within the qualified PSP(s) within the building.			
Seattle City Light	3	Negative	The reasoning for this vote is as follows: As noted in the Progress Energy submittal to NERC, they have cited the requirements for Critical Cyber Assets (CCAs) to be contained within the Electronic Security Perimeter (ESP) and for the ESP to be contained within the Physical Security Perimeter. However, a scenario can easily develop whereby CCA's are connected via cable/wiring and the affected wiring runs outside of the ESP and sometimes outside of the Physical Security Perimeter. In some instances the wiring could be underground, in cable trays, and even via poles and towers. Therefore, the key issue to recognize is that the cables/wires may be in circumstances whereby complete encapsulation (i.e., to achieve the "6-sided wall" mandate) would be extraordinarily expensive, extremely difficult, and in many cases not add any added physical protection due to the location of the wire/cable and distance away from unauthorized tampering. Also, if the cables are still within the physical security perimeter but outside the ESP, then added protection is not necessarily value added from a security standpoint because physical access is still afforded but not accepted in the interpretation. Our recommendation is that the interpretation take into account the security buffer between the Electronic Security Boundary and the Physical Security Boundary for cables/wires. Secondly, it is also recommended that protection of the data is paramount and that some logical controls should be taken into account for data protection even though the cable may be external to the ESP. Thirdly, encapsulating cable with conduit, cages or other "6-sided wall" protective measures may not be reasonable for the security value add and that the interpretation should take into account the physical location of the wires/cables that prevent an unauthorized party from tampering with the physical layer of the equipment.
Response: The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.			

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The scenario described by the commenter wherein two physically separate Cyber Assets that are individually classified as each having its own ESP would indeed not require physical access protection for the connective wiring. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. These measures can account for data protection. The recommendation to address data in motion is currently included in the work of the CSO706 Project.			
Tampa Electric Co.	3	Negative	Tampa Electric Company’s Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry’s attention and attempting to clarify this issue. Tampa Electric Company has several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach may be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: • These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. • The primary DCS vendors in our environment do not offer or support an approved mechanism for encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. • The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, Tampa Electric recommends that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective

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			based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations . We believe that the Standard Authorization Request should be modified to address concerns and issues related to: • Unauthorized access to the ESP through access to physical cabling. • Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. • Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.
Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets "alternative measures" to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project.			
Wisconsin Public Service Corp.	3	Negative	The interpretation for CIP-006 significantly expands the scope of the standard and needs to go through through the SAR process. The inclusion of communications network wiring is a shift from previous industry understanding and is contrary to responses for Frequently Asked Questions posted on the NERC website. Standard CIP-002-1 — Cyber Security — Critical Cyber Assets 11. Question: Do communication-related Cyber Assets for Critical Cyber Assets require protection under the Cyber Security Standards? Answer: Communications is not covered under this standard because communications are often leased by the Responsible Entities and the technologies for existing Cyber Assets do not always support encryption or other possible security alternatives. Asset owners are encouraged, whenever possible, to provide communications or communication systems with the same protection as their associated Critical Cyber Asset. Standard CIP-005-1 Cyber Security — Electronic Security 2. Question: I am connected to other partners Electronic Security Perimeters through a Wide Area Network (WAN) connection. What is now included in the Electronic Security Perimeter? Is the connection to the partner included? Answer: The standard states that where discrete Electronic Security Perimeters are connected by communication lines, the communication lines are not included in the Electronic Security Perimeter. 15. Question: Is a physically isolated and dedicated network required for connections between Electronic Security Perimeters? Answer: No, physical isolation is not required, nor is a dedicated link required. The standard does not specify any requirement for communication between discrete Electronic Security Perimeters, since this is currently beyond the scope of these standards. It

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			is possible for the data between discrete perimeters to be carried over a shared infrastructure such as a shared WAN, or to be carried over dedicated links. However, the Responsible Entity must ensure that the access control devices (such as firewalls) at the access points to the Electronic Security Perimeters do not permit unauthorized access to the Electronic Security Perimeters and the Cyber Assets within them. When data is carried over a shared infrastructure, the Responsible Entity should ensure as well that the data has not been changed in transit. Logical or virtual separation of the data in a shared infrastructure can be accomplished by using existing technologies such as virtual circuits and communication tunnels. Encryption or other data integrity checking technologies can also ensure that data is not changed in transit, provided performance and latency requirements for the applications are satisfied. Standard CIP-006-1 — Cyber Security — Physical Security 20. Question: Does the standard require entities to protect telecommunications services and facilities that serve physical security system assets? Answer: CIP-002 through CIP-009 do not address telecommunications.
Response: The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. The RFI response team clarifies in a revised interpretation response that physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. Protection of communication systems that reside within an ESP is required. The Frequently Asked Questions posted on the NERC website is a guidance document and is not mandatory and enforceable as NERC standards are. However, question #11 (reproduced below) refers to assets that are not owned by the Responsible Entity such as third-party telecommunications company equipment. **11. FAQ - Question:** *Do communication-related Cyber Assets for Critical Cyber Assets require protection under the Cyber Security Standards?* **Answer:** Communications is not covered under this standard because communications are often leased by the Responsible Entities and the technologies for existing Cyber Assets do not always support encryption or other possible security alternatives. Asset owners are encouraged, whenever possible, to provide communications or communication systems with the same protection as their associated Critical Cyber Asset. In addition, the figure associated with Question 2 for CIP-005-1 (Page 12 of the FAQ) specifically addresses the commenter's concerns regarding interconnectivity of ESP's over Wide Area Networks. This interpretation does not change the exclusion of communication networks outside of an ESP from the standard. In this instance the wiring is clearly stated by Progress Energy to be within a single ESP.			
Xcel Energy, Inc.	3	Negative	While Xcel Energy generally supports what we understand to be the intent of the interpretation, we feel it is not clear and could create further ambiguity. An interpretation should be clear and not create further room for interpretation. As explained to us by a member of the Cyber Security Order 706 SAR Drafting Team, the interpretation is designed to address the situation where there are potentially two separate physical security perimeters (PSP) with assets that are part of the same ESP -- such as two separate rooms, a data center and an operations center, that both have critical cyber assets and individual physical security perimeters. You could still have one ESP for the single building -- however, since the wiring connecting the assets in each of these

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			rooms leaves the physical security perimeters, you need to protect the wiring with a physical boundary (conduit), or encrypt the data. We feel strongly that this interpretation, as written, could be implemented and/or enforced inconsistent with what the drafting team intended, and recommend a new draft of the interpretation, including a diagram, be developed. Also, since this interpretation will likely have a substantial impact on entities, an implementation plan should be considered.
Response: The RFI response drafting team has clarified what it interprets "alternative measures" to mean in the revised response and believes the phrase "alternative measures" is neutral in its scope. The team understands the desire for more specificity and prescription, such as in a diagram, but believes that could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Alliant Energy Corp. Services, Inc.	4	Negative	CIP-005 - R1.3 specifically excludes the connecting cabling from the CIP standards. There can not be such conflicting statements between standards.
Response: Although the drafting team is limited to respond to this request from Progress Energy, to the point about "communication links" cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
Consumers Energy	4	Negative	Consumers Energy's understanding of the requirements of CIPS-005-1 and CIPS-006-1 as they were being developed and as they exist today allowed for discrete non-contiguous physical security perimeters to protect cyber assets contained within a single electronic security perimeter, presumably by excluding the communication network and data passing over the communication network as being defined as Cyber Assets requiring physical protection. We believe that this view is consistent with good utility practice utilized at a number of North America's control centers and generating plants. In extending the definition of Cyber Asset to include data and the communication network, the Interpretation clearly goes beyond the scope intended by the original drafters of the Standards. CIP-002-1 R3, Critical Cyber Asset Identification, refers to several examples of possible Critical Cyber Assets, all of which can be considered computer systems or devices possessing a central processing unit. Seven of the nine requirements in CIP-007-1 refer to Cyber Assets and clearly are intended to apply to computer systems, and none of the nine requirements specifically address network cables or data. Had the original intent of the standards been to include the communication networks within an electronic security perimeter as Cyber Assets requiring physical protection we would have expected the standard to address appropriate protection where six-wall physical protection (complete with access control and monitoring) is not necessary (such as with buried portions of the network) or practical (such as within raceways or conduit). Additionally, the time required to re-wire such networks so as to provide six-wall physical protection is significantly longer than the time required to provide six-wall physical protection to the access points to Cyber Assets within the Electronic Security Perimeter. Further, had the original intent of the standards been to include data that passes over the communication network, the standard should have discussed the issues associated with transporting, storing and restoring back-up tapes and other removable media so as to protect cyber assets in the event the back-up data is re-introduced to the electronic security perimeter. We

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			suggest the actual intent of the CIP Standards is to define as a Cyber Asset only those devices with a central processing unit. These are the devices susceptible to remote attack and compromise. We believe the primary intent of the present version of the CIP Standards is to protect against remote compromise of those assets. The apparent intent of the Interpretation, to require all network cabling be protected by a six-wall boundary, goes beyond the intent of the CIP Standards as they were developed and implemented. CIP-006-1 R1.1 states "ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter." This does not require a piece of hardware without a CPU, such as a network cable, to reside within a six-wall boundary. Consumers Energy argues that protecting communication network cabling residing in an area entirely within the reasonable and prudent control of the Responsible Entity is beyond the scope of the present CIP Standards. Had the intent of the requirement been to include all communication network and data as Cyber Assets requiring physical protection, the wording should have stated such. If the apparent intent of the Interpretation, to require network cabling to be contained within a six-wall boundary, is accepted, there will be no distinction between "in-house" cabling and connections carried through public networks. This ignores the different threat exposure of the two types of communication circuits. This Interpretation will divert money and other resources from mitigating higher threat exposures, such as man-in-the-middle attacks on unencrypted external communications circuits, to this lower threat exposure. We propose the following wording to replace the existing interpretation: Response: The Physical Security Perimeter is required to protect the access points to Critical Cyber Assets within the Electronic Security Perimeter. For dedicated communication networks within a discrete Electronic Security Perimeter under the normal reasonable and prudent control of the Responsible Entity, all elements of such network do not require to be contained within the Physical Security Perimeter so long as all access points to the Critical Cyber Assets within the Electronic Security Perimeter are also within a Physical Security Perimeter. CIP-005-1 R1.1 refers to " any externally connected communication end point (for example, dial-up modems) " as specifically identified as an access point to the Electronic Security Perimeter. The use of "externally connected" in this context refers to communication facilities outside the control of the Responsible Entity. Examples of such connections would include dial-up or leased telephone or data circuits, commercial packet-switched networks, wireless networks, or the Internet. Examples of connections not considered to be "external" would include local area networks between floors in a building or between buildings in a campus environment.

Response:

The RFI response drafting team believes the commenter's presumption that protection is not required for wiring between "discrete non-contiguous physical security perimeters" is not justified. The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 justifiably applies.

The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected.

Although the drafting team is limited to respond to this request from Progress Energy, to the point about "communication links" cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.

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The drafting team believes that the other concerns raised by the commenter, including transfer of backup tapes and other removable media, is best addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project.			
Madison Gas and Electric Co.	4	Negative	We disagree with the interpretation because it adds language that needs further interpretation and does not address our confusion in the Standard regarding when data traveling over a network needs to be protected and when it does not. The interpretation implies the measures referenced in CIP006, R1.1, focus on preventing physical access that would allow data to be tampered with in transit. Can we assume the focus is not on preventing physical access that allows data to be gathered/inspected, but rather to prevent tampering with the data? If so, would using optical fibers carrying data communication between two physical security perimeters be a sufficient physical control, assuming fiber provides a higher level of security to protect the data from tampering. Do optical fibers contained within a continuous, fully-jacketed cable, the only end points of which are contained within separate six-sided physical security perimeters, meet the requirements of the Standard under this interpretation? If not, what constitutes the physical security perimeter and what constitutes a physical access point? Please provide guidance, including examples, on the "alternative protective measures" that would be acceptable to meet the standard. The standards are confusing because of the explicit exemption under the Introduction section, Item 4.2.2, of each standard that excludes "Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters." We assume "communication networks" and "communication links between discrete ESP's" are two different things, since they are referenced separately in other parts of the Standard. Communication links between discrete ESP's are referenced in CIP-005, R1.3, as being outside of the ESP. This reference does not help to clarify the exemption. In addition, communication networks are not referenced in CIP-005, R1.3, or anywhere else except in the definition of Cyber Assets. To say that communication networks are exempt from the Standard implies the data traveling on those networks are also exempt. If this is incorrect, what is NERC's interpretation of the explicit exemption? From a protection standpoint, if there is a difference between the wire and the data traveling across the wire, that needs to be explicitly defined. Where does the Standard state whether data traveling between ESP's does or does not have to be protected?
Response: The RFI response drafting team agrees that protection of data in motion is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. This request from Progress Energy must be addressed in the formal interpretation process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team disagrees with the commenter that exemption in R4.2.2 applies because the specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-			

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006-1 indeed applies. In the revised response to Progress Energy, the drafting team interprets alternative measures to include approaches that are physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Seattle City Light	4	Negative	The reasoning for this vote is as follows: As noted in the Progress Energy submittal to NERC, they have cited the requirements for Critical Cyber Assets (CCAs) to be contained within the Electronic Security Perimeter (ESP) and for the ESP to be contained within the Physical Security Perimeter. However, a scenario can easily develop whereby CCA's are connected via cable/wiring and the affected wiring runs outside of the ESP and sometimes outside of the Physical Security Perimeter. In some instances the wiring could be underground, in cable trays, and even via poles and towers. Therefore, the key issue to recognize is that the cables/wires may be in circumstances whereby complete encapsulation (i.e., to achieve the "6-sided wall" mandate) would be extraordinarily expensive, extremely difficult, and in many cases not add any added physical protection due to the location of the wire/cable and distance away from unauthorized tampering. Also, if the cables are still within the physical security perimeter but outside the ESP, then added protection is not necessarily value added from a security standpoint because physical access is still afforded but not accepted in the interpretation. Our recommendation is that the interpretation take into account the security buffer between the Electronic Security Boundary and the Physical Security Boundary for cables/wires. Secondly, it is also recommended that protection of the data is paramount and that some logical controls should be taken into account for data protection even though the cable may be external to the ESP. Thirdly, encapsulating cable with conduit, cages or other "6-sided wall" protective measures may not be reasonable for the security value add and that the interpretation should take into account the physical location of the wires/cables that prevent an unauthorized party from tampering with the physical layer of the equipment.
Response: The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006. The scenario described by the commenter wherein two physically separate Cyber Assets that are individually classified as each having its own ESP would indeed not require physical access protection for the connective wiring. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. These measures can account for data protection. The recommendation to address data in motion is currently included in the work of the CSO706 Project.			

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Seminole Electric Cooperative, Inc.	4	Negative	Seminole endorses the comments of Tampa Electric Company as replicated below: Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry's attention and attempting to clarify this issue. We have several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach my be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: ? These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. ? The primary DCS vendors in our environment do not offer or support an approved mechanism for encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. ? The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, we recommend that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations . We believe that the Standard Authorization Request should be modified to address concerns and issues related to: ? Unauthorized access to the ESP through access to physical cabling. ? Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. ? Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.

Response:

The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets "alternative measures" to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden.

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However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Wisconsin Energy Corp.	4	Negative	Interpetation is overreaching
Response: The RFI response drafting team does not expand the meaning of but rather interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
WPS Resources Corp.	4	Negative	The interpretation for CIP-006 significantly expands the scope of the standard and needs to go through through the SAR process. The inclusion of communications network wiring is a shift from previous industry understanding and is contrary to responses for Frequently Asked Questions posted on the NERC website.
Response: The RFI response drafting team does not expand the meaning of but rather interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
AEP Service Corp.	5	Negative	Although we agree that a true "systems" approach to data protection would also include the data paths, we are concerned about an element that we believe should be included in any determination of communication path physical security. Physical protection (given the relatively controlled locations of some of the data paths in question) should be determined by a risk-based assessment. This would be particularly focused on the likelihood of intrusion given the overall physical environment and other factors (cables buried, guard forces, monitoring cameras, etc.), some of which may qualify as acceptable alternative measures. We believe that this topic should be addressed during the formal development of the next iteration of CIP standards to clarify requirements and include risk factors and a rational, realistic approach. For example, securing a facility housing coal handling systems makes complete sense from a potential intrusion perspective. This is less the case with the cabling running externally from the facility to the control room, often buried and not easily or inobtrusively accessible. Because of the factor listed above, AEP is casting a negative vote for this interpretation. We would prefer that it be addressed fully during the development of the next set of NERC CIP standards.
Response:			

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The RFI response drafting team agrees that this is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Allegheny Energy Supply Company, LLC	5	Negative	Allegheny Energy is concerned with the SAR drafting team interpretation that wiring within an ESP be considered a Cyber Asset or Critical Cyber Asset. Allegheny Energy agrees that the wiring (and information transmitted by such wiring) within an ESP needs to be protected; however, Allegheny Energy does not agree that the wiring needs to be classified and protected as a defined cyber asset. NERC defines cyber assets as programmable electronic devices and communication networks including hardware, software, and data and does not include the language “including the wiring that comprises the physical media supporting the network”. Allegheny Energy believes the best method to determine protection measures for the wiring (and information transmitted by such wiring) is to create a holistic approach to communication network and data communication link protection through the Standards process that specifically addresses these issues. This new Standard could address communication network and data communication link security issues, including copper cabling, fiber optic cabling, and wireless implementations. By the interpretation stating that network wiring is a cyber asset or potentially a critical cyber asset in an effort to physically secure the wiring, this statement would additionally impose all of the requirements of the CIP standard that are applicable to cyber assets and in essence make entities non-compliant since many requirements cannot be accomplished for wiring.
Response: The RFI response drafting team agrees that this is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. As such the RFI response drafting team has clarified that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
City of Tallahassee	5	Negative	CIP-005-1, R1.3 states: "Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s)."

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			Since it is not within the Electronic Security Perimeter, it does NOT need to be within a Physical Security perimeter that is required in CIP-006-1, R1.1. (Glossary) Cyber Assets: "Programmable electronic devices and communication networks including hardware, software, and data." I disagree that this includes the "wires". The "communication links connecting" are the "wires" and they are excluded per CIP-005, R1.3. We cannot have one standard saying the wires are included and another saying they are not!
Response: Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
Colmac Clarion/Piney Creek LP	5	Affirmative	Appears to adequately require either 'six boundary' enclosure or entity description of protective measures on wiring or components outside of same. Doesn't require that entity methods equal six wall protection however.
Response: Thank you for your comment. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Consumers Energy	5	Negative	Consumers Energy’s Comments to Accompany a “No” Vote on NERC 2008-10 August 6, 2008 **2008-10 Goes Beyond the Intent of the Standards** In extending the definition of Cyber Asset to include data and the communication network, the Interpretation clearly goes beyond the scope intended by the drafters of the Standards. CIP-002-1 R3, Critical Cyber Asset Identification, refers to several examples of possible Critical Cyber Assets, all of which can be considered computer systems, devices possessing a central processing unit. Seven of the nine requirements in CIP-007-1 refer to Cyber Assets and clearly are intended to apply to computer systems, not network cables or data. **Data and Cables Would Become Critical Cyber Assets** If this interpretation passes, network cables and data will be considered Cyber Assets. Since it is difficult to conceive of an Asset that uses a network where data and networks are not essential to the operation of that Asset, data and network cabling will become Critical Cyber Assets. This will be true for control centers, generating plants and substations. **Data as a Critical Cyber Asset** The act of identifying data as a Critical Cyber Asset has far-reaching implications. Will removable media such as backup tapes need to be stored within an Electronic Security Perimeter? How can media so protected be

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			moved to an off-site storage location? **Actual Intent - Cyber Asset Has CPU** Consumers Energy suggests the actual intent of the CIP Standards is to define as a Cyber Asset only those devices with a central processing unit. These are the devices susceptible to remote attack and compromise. Consumers Energy further suggests the primary intent of the present version of the CIP Standards is to protect against remote compromise. **Intent of Interpretation Goes Too Far for This Stage** Consumers Energy also suggests that the apparent intent of the Interpretation, to require all network cabling be protected by a six-wall boundary, goes beyond the intent of the CIP Standards in their present form. CIP-006-1 R1.1 states “ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter.” This does not require a piece of hardware without a CPU, such as a network cable, to reside within a six-wall boundary. Consumers Energy argues that protecting network cabling residing in an area entirely within the control of the Responsible Entity is beyond the scope of the present CIP Standards. Had the intent of the requirement been to include all connections outside the ESP, the wording should have stated such. Threats and Priorities If the apparent intent of the Interpretation, to require network cabling to be contained within a six-wall boundary, is accepted, there will be no distinction between “in-house” cabling and connections carried through public networks. This ignores the different threat exposure of the two types of communication circuits. This Interpretation will divert money and other resources from mitigating higher threat exposures, such as man-in-the-middle attacks on unencrypted external communications circuits, to this lower threat exposure. **Proposed Rewording** Consumers Energy proposes the following wording to replace the existing interpretation: Response: CIP-006-1 R1.1 refers to “any externally connected communication end point (for example, dial-up modems)” as specifically identified as an access point to the Electronic Security Perimeter. The use of “externally connected” in this context refers to communication facilities outside the control of the Responsible Entity. Examples of such connections would include dial-up or leased telephone or data circuits, commercial packet-switched networks, wireless networks, or the Internet. Examples of connections not considered to be ”external” would include local area networks between floors in a building or between buildings in a campus environment.

Response:

On the matter of wiring, it is clear that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset.

The RFI response drafting team agrees and acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also notes that Critical Cyber Asset classification is an important issue and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. Therefore, the

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matter of data protection is not directly address by this RFI response. The drafting team does not agree that protection of only Cyber Assets with CPUs is the intent of the CIP standards. The drafting team believes that the requirement clearly states that “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. The RFI response drafting team appreciates the suggested replacement wording, but believes it does not meet the objective of CIP-006-1.			
Detroit Edison Company	5	Negative	The following are Detroit Edison's reasons for voting No: The NERC Glossary defines Cyber Assets as “Programmable electronic devices and communication networks including hardware, software, and data”. Detroit Edison believes that this definition relating to the network is to include active devices that comprise the network, not the transmission media itself. Thus routers, switches, hubs, etc. are cyber assets, wiring is not. Detroit Edison's opinion on protecting cabling between physical security perimeters fully contained within an otherwise adequately secured facility is that the cable is sufficiently protected following guidance provided by NIST. Additional protection can be provided by covering the cable trays where they are easily accessible. "NIST SP800-53 PE-4 Access Control For Transmission Medium, Supplemental Guidance: Physical protections applied to information system distribution and transmission lines help prevent accidental damage, disruption, and physical tampering. Additionally, physical protections are necessary to help prevent eavesdropping or in transit modification of unencrypted transmissions. Protective measures to control physical access to information system distribution and transmission lines include: (i) locked wiring closets; (ii) disconnected or locked spare jacks; and/or (iii) protection of cabling by conduit or cable trays." Note that conduit and cable tray is specified as adequate protection by NIST however, if the interpretation is approved as written a completely enclosed six wall boundary would be required. Does this mean that all conduit bodies, pull boxes, cable tray covers, and open cable trays would become access points subject to CIP-006? "FERC Order 706 paragraph 224: Congressional Representatives state that NIST research prepared a technical report comparing the proposed CIP Reliability Standards with SP 800-53. This technical report found that an organization conforming to the baseline set of security controls in SP 800-53 will also comply with the management, operational and technical security requirements of the CIP Reliability Standards, though the converse may not be true." Detroit Edison believes that the outer barrier cable jacket, designed and manufactured to protect the data transport media within the jacket, represents a comprehensive six wall cable barrier and furthermore, completely enclosing wiring between physical security perimeters with a second protective measure such as a conduit, would be unduly burdensome, increase the risk of creating adjacency hazards and would not significantly improve the security posture of the critical cyber assets in the electronic security perimeter. Detroit Edison further supports the use of alternative protective measures such as data encryption where technically feasible, over the use of conduit,

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			which significantly provides enhanced security over the use of conduit alone.
Response: On the matter of wiring, it is clear that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The examples of cable protection cited in the comment appear to be viable physical approaches; however, the conclusion that a six-wall bounded physical solution is the only acceptable one is not accurate. The Requirement R1.1 of CIP-006-1 clearly states that “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
FirstEnergy Solutions	5	Negative	FE thanks the SAR team for their efforts in developing an interpretation for CIP-006-1 Req. R1.1 in response to Progress Energy's request. However, we have cast a Negative vote for the following reasons and ask the team to consider our comments and suggested revision. We feel that the proposed interpretation fails to provide the industry with a clear direction related to the question posed by Progress Energy. As stated, the interpretation largely restates the definition of a Cyber Asset contained in the NERC Glossary of Terms, and a re-statement of CIP-006 R1.1. The interpretation states that "The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." However, the actual definition from the NERC Glossary states that “Cyber Assets include programmable electronic devices and communication networks including hardware, software, and data." Further, in the CIP standards development process the communications paths were deliberately excluded from the scope of the Standards, especially third party communication assets. Accordingly, we concur with the aspect of the interpretation that implies that the communications hardware devices and closets that include critical cyber assets should be secured inside the PSP, but that the physical utility-owned wiring should not be classified as Cyber Asset as the interpretation indicates. This would be consistent with the explicit exclusion of the third party communication assets embodied within the standards. We agree that the definition includes the data as a Cyber Asset, but do not agree that the definition includes the physical wiring as a Cyber Asset. Accordingly as a potential modification to the interpretation, we suggest a revision to the interpretation as follows: "The definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: The RFI response drafting team asserts that physical media (wiring) is a component of a communication network within an ESP and shall be secured inside the Physical Security Perimeter.			

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The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Lincoln Electric System	5	Affirmative	Any wiring within the electronic security perimeter must be protected by a six-wall physical security perimeter. Wiring external to the electronic security perimeter constitutes a "communications link", and therefore does not need to be protected by the physical security perimeter. It appears that some confusion on this issue stems from the fact that Progress Energy's original question isn't even possible - it pertains to wiring within the electronic security perimeter, but outside the physical security perimeter. According to Requirement 1.1, the electronic security perimeter must be a subset of the physical security perimeter. Therefore, any wiring within the electronic security perimeter must also fall within the physical security perimeter by default.
Response: Thank you for your comment. The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.			
Manitoba Hydro	5	Negative	Manitoba Hydro agrees with the part of the interpretation provided by the SAR drafting team that protection of the data transmitted over wires within an Electronic Security Perimeter as the intent of the requirement. This provides more flexibility to meet the standard by allowing not only physical protection of the wire, but also alternative protective measures for the data such as encryption. Responsible Entities should take reasonable measures to protect the data within an Electronic Security Perimeter. However, Manitoba Hydro does not agree with the part of the interpretation provided by the SAR drafting team that "the definition of a Cyber Asset includes both the data and communication networks, including the wiring that comprises the physical media supporting the network." It should be made clear that the wiring within an Electronic Security Perimeter is considered as part of the Cyber Asset (programmable device or communication network) and that wiring is not itself a Cyber Asset. Since the term communication network is not a NERC defined or clearly understood industry term, the interpretation should not use communication network (or network) as part of any clarifying statement.
Response: The RFI response drafting team agrees and submits a revised interpretation response stating the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. However, the drafting team disagrees with removal of the term communication network in the RFI response, as it already referenced in the NERC Glossary.			

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Northern States Power Co.	5	Negative	While Xcel Energy generally supports what we understand to be the intent of the interpretation, we feel it is not clear and could create further ambiguity. An interpretation should be clear and not create further room for interpretation. As explained to us by a member of the Cyber Security Order 706 SAR Drafting Team, the interpretation is designed to address the situation where there are potentially two separate physical security perimeters (PSP) with assets that are part of the same ESP -- such as two separate rooms, a data center and an operations center, that both have critical cyber assets and individual physical security perimeters. You could still have one ESP for the single building -- however, since the wiring connecting the assets in each of these rooms leaves the physical security perimeters, you need to protect the wiring with a physical boundary (conduit), or encrypt the data. We feel strongly that this interpretation, as written, could be implemented and/or enforced inconsistent with what the drafting team intended, and recommend a new draft of the interpretation, including a diagram, be developed. Also, since this interpretation will likely have a substantial impact on entities, an implementation plan should be considered.
Response: The RFI response drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope. The team understands the desire for more specificity and prescription, such as in a diagram, but believes that could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Pacific Gas and Electric Company	5	Negative	The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of “alternative protective measures” i not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			

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PPL Generation LLC	5	Negative	Response: The definition of a Cyber Asset includes both the data and the routable protocol-based communication network, including the wiring that comprises the physical media supporting the network. The intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures. Alternative protection measures could include 24 x7 monitoring, alerting, and logging of attempts at or actual compromise of the network. Supporting information: Based on CIP-002, R3, the definition introduced by the Interpretation should be limited to the "routable protocol-based" communication networks associated with Cyber Assets.
Response: The RFI response team agrees with the comment that the objective is to protect the data. To do so requires measures to prevent tampering of Cyber Assets. However, the RFI response team disagrees with the last point. The drafting team asserts that the requirement R1.1 does not limit application of alternative measures only to “routable protocol-based communication networks” and therefore doing so is unjustified.			
Reliant Energy Services	5	Negative	Reliant Energy is in agreement with the following comment posted by First Energy at 3:54 pm on August 13, on PJM’ NERC Standard e-Room. That is; “he definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly; the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: On the matter of wiring, it is clear that the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response drafting team agrees that protection can be provided through alternative measures that include use of a combined/complementary physical and logical approach to achieve the same or better protection.			
Salt River Project	5	Negative	In cases where the building hosting the Critical Asset is under control of the Registered Entity, the building itself should serve as the six sided physical container. The possibility of an employee, contractor or guest pulling up a floor panel or ceiling tile, finding the right cable or fiber, and then having a way to tap or monitor the line is not a credible threat
Response: The building hosting the Critical Asset, when under the control of the Responsible Entity, is a qualified Physical Security Perimeter only when access is controlled per CIP-006-1 and all personnel with unescorted access have met the applicable requirements of the CIP standards, including completion of personnel risk assessments and training. If the entire building is not a qualified PSP, then alternative measures must be applied to protect wiring not enclosed within the qualified PSP(s) within the building.			

Entity	Segment	Vote	Comment
Southern California Edison Co.	5	Negative	Southern California Edison Company (SCE) SCE appreciates the opportunity to provide comments on the NERC Standards Development team' proposed interpretation for CIP-006-1's Requirement 1.1 (Proposed Interpretation). SCE cast a negative vote on the Proposed Interpretation because it causes additional confusion and could result in unreasonable and impractical consequences that would not improve the security of the Cyber Assets or the Electronic Security Perimeter. SCE believes issues identified by Progress Energy should be addressed during the review of CIP-006 scheduled to take place in 2009. Supporting reasons for this position are provided below. The proposed interpretation states that Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." CE shares a concern raised by WECC in their position paper that if the physical media used to transport critical data is considered a Critical Cyber Asset, then it would require all of the requisite physical protections specified in the existing CIP standards. SCE feels physical media supporting the network cannot be subject to the physical protections specified in CIP standards. For example, if a network cable runs from a Critical Cyber Asset situated within an identified Physical Security Perimeter to a point or through any area that is outside the identified Physical Security Perimeter, it is not clear that taking measures to protect the cable from tampering, and potentially having to monitor access to the cable, would be an appropriate way to secure the network. Access to SCE's communications network, and the data which streams across it, is strictly controlled by an Electronic Security Perimeter which personnel and equipment/ application(s) are given narrow access rights dependent on their usage requirements. The allowance of "alternative protective measures" for physical media supporting the network is also not clearly defined, and could even be interpreted to allow for logical protections without physical protection of Cyber Assets. This clearly would not be an appropriate outcome as pointed out in WECC's position paper as well. The uncertainty created by the interpretation's reference to alternative protective measures is another reason SCE voted against the interpretation. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances. In closing, it is SCE's opinion that the Proposed Interpretation and the issues brought-up in relation to the actual definition of Cyber Asset be fully addressed and incorporated into the revised CIP-006 standard. Pursuant to NERC's Reliability Standards Development Plan an effort to revise the CIP standards will be initiated in 2009.

Response:

The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project.

However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.

The drafting team recognizes there are instances that pose technical and/or costly challenges to protection of Cyber Assets and clarifies that the current

Entity	Segment	Vote	Comment
Requirement includes the use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. To the commenter's point regarding more prescriptive and specific language, the drafting team believes that it could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Tampa Electric Co.	5	Negative	Tampa Electric Company's Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry's attention and attempting to clarify this issue. Tampa Electric Company has several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach may be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: • These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. • The primary DCS vendors in our environment have stated to us that they do not offer or support an approved mechanism for firewalling within the DCS network or encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. • The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, Tampa Electric recommends that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations. We believe

Entity	Segment	Vote	Comment
			that the Standard Authorization Request should be modified to address concerns and issues related to: • Unauthorized access to the ESP through access to physical cabling. • Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.
Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets "alternative measures" to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Tennessee Valley Authority	5	Negative	The factors, which lead to this conclusion, are the exponential increase in scope and cost for the implementation of physical security applied to the communication media.
Response: CIP-006-1 requires all Cyber Assets within an ESP to be enclosed within a PSP. The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets "alternative measures" to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden.			
U.S. Bureau of Reclamation	5	Negative	This issue raises a question as to the NERC requirements for the physical protection of critical cyber assets that fall outside of readily defined Physical Security Perimeters (PSPs). The connection between the two PSPs is a communications line employing a routable protocol and may be based on microwave, radio, copper, or fiber technologies. For circuits that go between physical structures separated by more than several feet, the 6 wall requirement is impractical. NERC's response to the question raised was consistent with their overall requirements in the sense that they did not relax protection requirements for Critical Cyber Assets (specifically wiring) external to an Electronic Security Perimeter (ESP). Reclamation will be significantly impacted by this interpretation for its Critical Cyber Systems that extend over several physical sites. Specifically in cases where those sites are interconnected with communications circuits employing "routable protocols." In those instances, since physical protection of the circuits will be impractical or impossible, Reclamation will need to employ "alternate protective measures" on communications lines interconnecting the physically distinct sites. We suggest NERC reconsider their requirements in cases where interconnections between sites remain within the same "control system" and where those interconnections are carried over privately owned circuits. The

Entity	Segment	Vote	Comment
			requirements NERC has outlined make very good sense (and we support them) where the connections go to external entities or where they are carried over public networks. We have no desire to change this aspect of the requirements. We are requesting special consideration be given to private networks between physical and electronic perimeters where those networks are owned/operated by the entities in question.
Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets “alternative measures” to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. The RFI response team is limited to interpreting the requirement of the existing standard. The request for consideration of private networks is best addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project.			
AEP Marketing	6	Negative	Physical protection (given the relatively controlled locations of some of the data paths in question) should be determined by a risk-based assessment. This would be particularly focused on the likelihood of intrusion given the overall physical environment and other factors (cables buried, guard forces, monitoring cameras, etc.), some of which may qualify as acceptable alternative measures. We believe that this topic should be addressed during the formal development of the next iteration of CIP standards to clarify requirements and include risk factors and a rational, realistic approach. For example, securing a facility housing coal handling systems makes complete sense from a potential intrusion perspective. This is less the case with the cabling running externally from the facility to the control room, often buried and not easily or in obtrusively accessible. Because of the factor listed above, AEP is casting a negative vote for this interpretation. We would prefer that it be addressed fully during the development of the next set of NERC CIP standards.
Response: The RFI response drafting team agrees that this is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Consolidated Edison Co. of New York	6	Negative	The interpretation is not clear and may modify the intention of the Standard and needs more work. The existing Standard requirement clearly states, "..all Cyber Assets in an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter", which must be protected.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring			

Entity	Segment	Vote	Comment
needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
FirstEnergy Solutions	6	Negative	FE thanks the SAR team for their efforts in developing an interpretation for CIP-006-1 Req. R1.1 in response to Progress Energy's request. However, we have cast a Negative vote for the following reasons and ask the team to consider our comments and suggested revision. We feel that the proposed interpretation fails to provide the industry with a clear direction related to the question posed by Progress Energy. As stated, the interpretation largely restates the definition of a Cyber Asset contained in the NERC Glossary of Terms, and a re-statement of CIP-006 R1.1. The interpretation states that "The definition of a Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network." However, the actual definition from the NERC Glossary states that Cyber Assets include programmable electronic devices and communication networks including hardware, software, and data." Further, in the CIP standards development process the communications paths were deliberately excluded from the scope of the Standards, especially third party communication assets. Accordingly, we concur with the aspect of the interpretation that implies that the communications hardware devices and closets that include critical cyber assets should be secured inside the PSP, but that the physical utility-owned wiring should not be classified as Cyber Asset as the interpretation indicates. This would be consistent with the explicit exclusion of the third party communication assets embodied within the standards. We agree that the definition includes the data as a Cyber Asset, but do not agree that the definition includes the physical wiring as a Cyber Asset. Accordingly as a potential modification to the interpretation, we suggest a revision to the interpretation as follows: "The definition of a Cyber Asset includes the data and the communication network including hardware, software, and data, however, the physical communication wiring that comprises the physical media supporting the network is not a Cyber Asset. The intent of the requirement is to protect the communication data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures."
Response: The RFI response drafting team asserts that physical media (wiring) is a component of a communication network within an ESP and shall be secured inside the Physical Security Perimeter. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. CIP-006 R1.1 states: “Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.” The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple			

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physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Lincoln Electric System	6	Affirmative	Any wiring within the electronic security perimeter must be protected by a six-wall physical security perimeter. Wiring external to the electronic security perimeter constitutes a "communications link", and therefore does not need to be protected by the physical security perimeter. It appears that some confusion on this issue stems from the fact that Progress Energy's original question isn't even possible - it pertains to wiring within the electronic security perimeter, but outside the physical security perimeter. According to Requirement 1.1, the electronic security perimeter must be a subset of the physical security perimeter. Therefore, any wiring within the electronic security perimeter must also fall within the physical security perimeter by default.
Response: Thank you for your comment. The RFI response drafting team agrees that the configuration in this instance involves two physically separate Cyber Assets that are collectively within a single ESP. Therefore, the interconnecting wiring shall comply with requirement R1.1 of CIP-006.			
Madison Gas and Electric Co.	6	Negative	We disagree with the interpretation because it adds language that needs further interpretation and does not address our confusion in the Standard regarding when data traveling over a network needs to be protected and when it does not. The interpretation implies the measures referenced in CIP006, R1.1, focus on preventing physical access that would allow data to be tampered with in transit. Can we assume the focus is not on preventing physical access that allows data to be gathered/inspected, but rather to prevent tampering with the data? If so, would using optical fibers carrying data communication between two physical security perimeters be a sufficient physical control, assuming fiber provides a higher level of security to protect the data from tampering. Do optical fibers contained within a continuous, fully-jacketed cable, the only end points of which are contained within separate six-sided physical security perimeters, meet the requirements of the Standard under this interpretation? If not, what constitutes the physical security perimeter and what constitutes a physical access point? Please provide guidance, including examples, on the "alternative protective measures" that would be acceptable to meet the standard. The standards are confusing because of the explicit exemption under the Introduction section, Item 4.2.2, of each standard that excludes "Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters." We assume "communication networks" and "communication links between discrete ESP's" are two different things, since they are referenced separately in other parts of the Standard. Communication links between discrete ESP's are referenced in CIP-005, R1.3, as being outside of the ESP. This reference does not help to clarify the exemption. In addition, communication networks are not referenced in CIP-005, R1.3, or anywhere else except in the definition of Cyber Assets. To say that communication networks are exempt from the Standard implies the data traveling on those networks are also exempt. If this is incorrect, what is NERC's interpretation of the explicit exemption? From a protection standpoint, if there is a difference between the wire and the data traveling across the wire, that needs to be explicitly defined. Where does the Standard state whether data traveling between ESP's does or does not have to be protected?

Entity	Segment	Vote	Comment
Response: The RFI response drafting team agrees that protection of data in motion is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. This request from Progress Energy must be addressed in the formal interpretation process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team disagrees with the commenter that exemption in R4.2.2 applies because the specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside a single ESP. Since the connective wiring is inside the ESP, Requirement R1.1 of CIP-006-1 indeed applies. In the revised response to Progress Energy, the drafting team interprets alternative measures to include approaches that are physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Manitoba Hydro	6	Negative	Manitoba Hydro agrees with the part of the interpretation provided by the SAR drafting team that protection of the data transmitted over wires within an Electronic Security Perimeter as the intent of the requirement. This provides more flexibility to meet the standard by allowing not only physical protection of the wire, but also alternative protective measures for the data such as encryption. Responsible Entities should take reasonable measures to protect the data within an Electronic Security Perimeter. However, Manitoba Hydro does not agree with the part of the interpretation provided by the SAR drafting team that "the definition of a Cyber Asset includes both the data and communication networks, including the wiring that comprises the physical media supporting the network." It should be made clear that the wiring within an Electronic Security Perimeter is considered as part of the Cyber Asset (programmable device or communication network) and that wiring is not itself a Cyber Asset. Since the term communication network is not a NERC defined or clearly understood industry term, the interpretation should not use communication network (or network) as part of any clarifying statement.
Response: The RFI response drafting team agrees and submits a revised interpretation response stating the definition of Cyber Asset in the NERC Glossary includes communication networks. Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. However, the drafting team disagrees with removal of the term communication network in the RFI response, as it already referenced in the NERC Glossary.			
PP&L, Inc.	6	Negative	Response: The definition of a Cyber Asset includes both the data and the routable protocol-based communication network, including the wiring that comprises the physical media supporting the network. The

Entity	Segment	Vote	Comment
			intent is to protect the data transmitted over the network within the ESP. Accordingly, the data must be protected from tampering, either through physical protection of the wiring or alternative protective measures. Alternative protection measures could include 24 x7 monitoring, alerting, and logging of attempts at or actual compromise of the network. Supporting information: Based on CIP-002, R3, the definition introduced by the Interpretation should be limited to the "routable protocol-based" communication networks associated with Cyber Assets.
Response: The RFI response team agrees with the comment that the objective is to protect the data. To do so requires measures to prevent tampering of Cyber Assets. However, the RFI response team disagrees with the last point. The drafting team asserts that the requirement R1.1 does not limit application of alternative measures only to “routable protocol-based communication networks” and therefore doing so is unjustified.			
Salt River Project	6	Negative	In cases where the building hosting the Critical Asset is under control of the Registered Entity, the building itself should serve as the six sided physical container. The possibility of an employee, contractor or guest pulling up a floor panel or ceiling tile, finding the right cable or fiber, and then having a way to tap or monitor the line is not a credible threat
Response: The building hosting the Critical Asset, when under the control of the Responsible Entity, is a qualified Physical Security Perimeter only when access is controlled per CIP-006-1 and all personnel with unescorted access have met the applicable requirements of the CIP standards, including completion of personnel risk assessments and training. If the entire building is not a qualified PSP, then alternative measures must be applied to protect wiring not enclosed within the qualified PSP(s) within the building.			
Southern California Edison Co.	6	Negative	Southern California Edison Company (SCE) SCE appreciates the opportunity to provide comments on the NERC Standards Development team’s proposed interpretation for CIP-006-1’s Requirement 1.1 (Proposed Interpretation). SCE cast a negative vote on the Proposed Interpretation because it causes additional confusion and could result in unreasonable and impractical consequences that would not improve the security of the Cyber Assets or the Electronic Security Perimeter. SCE believes issues identified by Progress Energy should be addressed during the review of CIP-006 scheduled to take place in 2009. Supporting reasons for this position are provided below. The proposed interpretation states that “Cyber Asset includes both the data and the communication network, including the wiring that comprises the physical media supporting the network.” SCE shares a concern raised by WECC in their position paper that if the physical media used to transport critical data is considered a Critical Cyber Asset, then it would require all of the requisite physical protections specified in the existing CIP standards. SCE feels physical media supporting the network cannot be subject to the physical protections specified in CIP standards. For example, if a network cable runs from a Critical Cyber Asset situated within an identified Physical Security Perimeter to a point or through any area that is outside the identified Physical Security Perimeter, it is not clear that taking measures to protect the cable from tampering, and potentially having to monitor access to the cable, would be an appropriate way to secure the network. Access to SCE’s communications network, and the data which streams across it, is strictly controlled by an

Entity	Segment	Vote	Comment
			Electronic Security Perimeter which personnel and equipment/ application(s) are given narrow access rights dependent on their usage requirements. The allowance of "alternative protective measures" for physical media supporting the network is also not clearly defined, and could even be interpreted to allow for logical protections without physical protection of Cyber Assets. This clearly would not be an appropriate outcome as pointed out in WECC's position paper as well. The uncertainty created by the interpretation's reference to alternative protective measures is another reason SCE voted against the interpretation. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances. In closing, it is SCE's opinion that the Proposed Interpretation and the issues brought-up in relation to the actual definition of Cyber Asset be fully addressed and incorporated into the revised CIP-006 standard. Pursuant to NERC's Reliability Standards Development Plan an effort to revise the CIP standards will be initiated in 2009.
Response: The RFI response drafting team acknowledges that the issue of data in motion (among others) is important and is being addressed by the CSO706 Project work that is ongoing. The RFI response drafting team also agrees that Critical Cyber Asset classification is an important issue, and it is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining whether physical protection is required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy. The drafting team recognizes there are instances that pose technical and/or costly challenges to protection of Cyber Assets and clarifies that the current Requirement includes the use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. To the commenter's point regarding more prescriptive and specific language, the drafting team believes that it could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Tampa Electric Co.	6	Negative	Tampa Electric Company's Response to Interpretation of CIP006-1 We would like to thank Progress Energy and the Cyber Security Drafting Team for bringing this concern to the industry's attention and attempting to clarify this issue. Tampa Electric Company has several concerns with the proposed interpretation as currently worded. This interpretation asserts that we must employ physical security (or alternative methods) to protect the wiring. While this type of approach may be achievable in a data center environment where the electronic security perimeter (ESP) is self contained within a room or a single building, it presents an enormous challenge from a generation distributed control system (DCS) perspective where an ESP spans multiple buildings. Additionally, many DCS implementations include remote human machine interfaces which are within the ESP, but distributed throughout the plant. The cost to physically protect the wiring in these environments to the level

Entity	Segment	Vote	Comment
			of CIP006 requirements would easily run into the millions of dollars for a single facility. Running the cable within conduit and encasing in concrete, which is common in many facilities, would still be insufficient to meet the monitoring, logging, and access control requirements of CIP006. In short, physical security solutions to this problem are not practical or cost effective based on the risk being mitigated. Alternative measures to physical security such as encrypted communication links or network segmentation through firewalls to create smaller, separate ESPs are not technically feasible today for most generation DCS networks: ? These technologies are unproven within a DCS environment and require vendor modifications, which will require extensive testing and coordination between the industry and the vendors. ? The primary DCS vendors in our environment have stated to us that they do not offer or support an approved mechanism for firewalling within the DCS network or encrypting data due to the network protocol and impact to the timing of data delivery across the DCS network. The time-sensitive nature of DCS data traffic makes these approaches impractical and introduces risk to reliability and multiple points of failure that are contrary to the intent of these reliability standards. ? The industry will likely introduce support issues by implementing these measures on their own. It is reasonable to expect that this will take much more time to accomplish than is possible within the existing implementation plan. Therefore, Tampa Electric recommends that the drafting team consider addressing this issue in the upcoming revisions to the standards, rather than issuing an interpretation under the existing standards which is unattainable. The revised standards should address specifically protection that is appropriate to cabling and is cost effective based on the risk being mitigated. The drafting team has already identified the need to consider issues surrounding data in motion, and extended LANS over geographically dispersed locations . We believe that the Standard Authorization Request should be modified to address concerns and issues related to: ? Unauthorized access to the ESP through access to physical cabling. ? Disrupting the operation of the critical cyber assets through tampering or destruction of the physical cabling. ? Alternative approaches to physically securing cable through technical means such as firewalls and encryption. This approach allows the industry and DCS vendors time to develop and implement solutions that enhance the overall security without introducing an excessive cost burden or increasing the risk to reliability.
Response: The RFI response drafting team recognizes the variety of challenges that protection of Cyber Assets pose. In the case of DCS equipment within a power plant environment, the technical issues are especially acute. The drafting team interprets “alternative measures” to include physical and logical approaches to protect the Cyber Asset. For the DCS environment, a combination of approaches is possible to achieve an equivalent level of protection without excessive cost burden. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Xcel Energy, Inc.	6	Negative	While Xcel Energy generally supports what we understand to be the intent of the interpretation, we feel it is not clear and could create further ambiguity. An interpretation should be clear and not create further room for interpretation. As explained to us by a member of the Cyber Security Order 706 SAR Drafting Team, the interpretation is designed to address the situation where there are potentially two separate physical security perimeters (PSP) with assets that are part of the same ESP -- such as two separate rooms, a data center and an operations center, that both have critical cyber assets and individual physical security perimeters. You could

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			still have one ESP for the single building -- however, since the wiring connecting the assets in each of these rooms leaves the physical security perimeters, you need to protect the wiring with a physical boundary (conduit), or encrypt the data. We feel strongly that this interpretation, as written, could be implemented and/or enforced inconsistent with what the drafting team intended, and recommend a new draft of the interpretation, including a diagram, be developed. Also, since this interpretation will likely have a substantial impact on entities, an implementation plan should be considered.
Response: The RFI response drafting team has clarified what it interprets "alternative measures" to mean in the revised response and believes the phrase "alternative measures" is neutral in its scope. The team understands the desire for more specificity and prescription, such as in a diagram, but believes that could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
California Energy Commission	9	Negative	The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: Physical media (wiring) is a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset. The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to "wires within a given facility or campus" and therefore doing so is unjustified. The drafting team has clarified what it interprets "alternative measures" to mean in the revised response and believes the phrase "alternative measures" is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Commonwealth of Massachusetts Department of Public Utilities	9	Negative	The interpretation should not include speculation as to the intent of the reliability standard.
Response:			

Entity	Segment	Vote	Comment
The RFI response drafting team does not speculate but rather interprets the standard as permitting "alternative measures" to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			
Oregon Public Utility Commission	9	Negative	The interpretation should not include speculation as to the intent of the standard. The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus. If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of "alternative protective measures" is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.
Response: The RFI response drafting team does not speculate but rather interprets the standard as permitting "alternative measures" to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering. The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response, and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset and would thus not qualify in and of itself as a Critical Cyber Asset. The drafting team believes the phrase "alternative measures" is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			
Electric Reliability Council of Texas, Inc.	10	Negative	This interpretation is an issue that should be handled through the full Standard review process.
Response: The RFI response drafting team agrees that this is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is			

Entity	Segment	Vote	Comment
among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Midwest Reliability Organization	10	Negative	MRO Response: CIP-005-1, R1.3 states: "Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s)." Since it is not within the Electronic Security Perimeter, it does NOT need to be within a Physical Security perimeter that is required in CIP-006-1, R1.1. (Glossary) Cyber Assets: "Programmable electronic devices and communication networks including hardware, software, and data." The MRO disagrees that this includes the "wires". The "communication links connecting" are the "wires" and they are excluded per CIP-005, R1.3. We cannot have one standard saying the wires are included and another saying they are not!
Response: Although the drafting team is limited to respond to this request from Progress Energy, to the point about “communication links” cited in CIP-005-1 R1.3, in this instance it does not apply because the wiring is clearly stated by Progress Energy to be within a single ESP.			
SERC Reliability Corporation	10	Negative	The interpretation indicates that the definition of a Cyber Asset includes the wiring that comprises the physical media supporting the [communications] network -- although this is not included in the NERC Glossary definition. The interpretation goes on to state that the intent is to protect the “data” transmitted over the network within the Electronic Security Perimeter rather than to protect “the facilities, systems, and equipment which if destroyed, degraded, compromised or otherwise rendered unavailable, would affect the reliability of the Bulk Electric System as a whole, not risk to a Responsible Entity’s individual asset” as described in Security Guidelines for the Electric Sector: Identifying Critical Assets. The interpretation merely restates the requirement of CIP-006-1, R1.1 to take (either Physical Security Perimeter or alternative) measures to control physical access of Critical Cyber Assets and adds confusion to the standard by introducing concepts contrary to other reference material provided by NERC.
Response: The definition of Cyber Asset in the NERC Glossary includes communication networks. The interpretation response team has reviewed its response and considers the physical media (wiring) a component of a communication network within an ESP, but the wiring itself is not a separate Cyber Asset; therefore, the network wiring needs to be protected. The RFI response drafting team interprets “alternative measures” to include use of a combined/complementary physical and logical approach to achieve the same or better protection. The alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed (“six-wall”) border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption or monitoring for circuit disruptions due to physical tampering.			

Entity	Segment	Vote	Comment
Southwest Power Pool	10	Negative	SPP believes the concerns raised in this interpretation are too important to let lie in an interpretation. Although the interpretation provides additional guidance about the intent of the standard, it is not good practice to keep the requirement as written. A rewrite of R1.1 under a clear scope is a better way for the industry to understand the intent.
Response: The RFI response drafting team agrees that this is an important issue and indeed is presently being addressed as part of the standards revision work of the Cyber Security Order 706 (CSO706) project. A risk-based assessment methodology for determining which assets need protection and the type of protection required is among the frameworks under consideration in the next iteration of CIP standards covered by the CSO706 project. However, interpretation requests are permitted as part of the standards development process. The work of the CSO706 team is not expected to be completed in time to address this RFI from Progress Energy.			
Western Electricity Coordinating Council	10	Negative	“The interpretation would be acceptable if language is added that limits the application of alternative protective measures to wires within a given facility or campus.” “If the physical media used to transport critical data is to be considered a Critical Cyber Asset, then it will require all of the requisite physical protections specified in the existing CIP Standards. The allowance of “alternative protective measures” is not clearly defined, and could be construed to allow for logical protections without physical protection. If the intent is to allow for logical protections, this could allow for other instances where the physical protection for Critical Cyber Assets is not required, and therefore, logical protections will suffice. This could erode the nature and intent of true physical protection over the long-term. If logical protections are to be allowed, the interpretation should state, in no uncertain terms, which types of protections are allowed, and under which specific circumstances.”
Response: The RFI response team asserts that the requirement R1.1 does not limit application of alternative measures only to “wires within a given facility or campus” and therefore doing so is unjustified. The drafting team has clarified what it interprets “alternative measures” to mean in the revised response and believes the phrase “alternative measures” is neutral in its scope and does not prefer physical to logical and vice versa. Nor does it imply the application of one to the exclusion of the other, i.e., a combination of approaches is possible. The drafting team also believes that more prescriptive and specific language could lead to the exclusion of equally effective measures and therefore has elected to avoid such language.			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:
Progress Energy requests a formal interpretation of CIP-006-1. R1.1.

In CIP_006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

The following revised interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the Cyber Security Order 706 SAR drafting team in response to industry comments received from the initial ballot:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Revised Response:
The definition of Cyber Asset in the *NERC Glossary of Terms Used in Reliability Standards* includes communication networks. Physical media (wiring) is a component of a communication network within an Electronic Security Perimeter, but the wiring itself is not a separate Cyber Asset.

The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside the Electronic Security Perimeter. Since the connective wiring is inside the Electronic Security Perimeter, Requirement R1.1 of CIP-006-1 applies.

CIP-006-1 R1.1 also provides: "Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." For wiring within the Electronic Security Perimeter that is external to a Physical Security Perimeter, the alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to data encryption, and/or circuit monitoring to detect unauthorized access or physical tampering.

From: Crews, David [mailto:david.crews@pgnmail.com]
Sent: Wednesday, April 02, 2008 5:05 PM
To: Gerry Adamski
Cc: Woods, Bruce; Goff, Edwin
Subject: Request for Interpretation CIP Standard

Progress Energy requests a formal interpretation of **CIP-006-1.** R1.1.

In **CIP_006-1**, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In **CIP-005-1,** Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In **CIP-002-1,** Requirement 3 states **"**Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

> **R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
>
> **R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
>
> **R3.3.** The Cyber Asset is dial-up accessible.

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Window Open

September 30–October 12, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2008-10: Interpretation for CIP-006-1 Requirement R1.1 for Progress Energy
An initial ballot window for a revised interpretation of standard CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 for Progress Energy is now open **until 8 p.m. EDT on October 12, 2009**.

Instructions:
Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps:
Voting results will be posted and announced after the ballot window closes.

Project Background:
Progress Energy asked if electronic security perimeter wiring external to a physical security perimeter must be protected within a six-wall boundary. The team has revised the interpretation based on stakeholder comments submitted during the initial ballot for the first draft of the interpretation.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2008-10_CIP-006_Interpretation_Progress.html

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Standards Announcement

Ballot Pool and Pre-ballot Window
August 31–September 30, 2009

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2008-10: Interpretation for CIP-006-1 Requirement R1.1 for Progress Energy

A revised interpretation of standard CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 for Progress Energy is posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EDT on September 30, 2009**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2008-10_RFI_PE_Rev1_in.

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

Progress Energy asked if electronic security perimeter wiring external to a physical security perimeter must be protected within a six-wall boundary. The team has revised the interpretation based on stakeholder comments submitted during the initial ballot for the first draft of the interpretation.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2008-10_CIP-006_Interpretation_Progress.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2008-10: Interpretation of CIP-006-1 for Progress Energy
The initial ballot for a revised interpretation of standard CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 for Progress Energy ended on October 12, 2009.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 79.92%
Approval: 74.47%

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps
As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background
Progress Energy asked if Electronic Security Perimeter wiring external to a Physical Security Perimeter must be protected within a six-wall boundary. The team revised the interpretation based on stakeholder comments submitted during the initial ballot for the first draft of the interpretation.

The request and interpretation are posted on the project page:
http://www.nerc.com/filez/standards/Project2008-10_CIP-006_Interpretation_Progress.html

Standards Development Process
The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria
Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Ballot Results	
Ballot Name:	Project 2008-10 Interpretation - Progress Energy - CIP-006-1 Revised_in
Ballot Period:	9/30/2009 - 10/12/2009
Ballot Type:	Initial
Total # Votes:	199
Total Ballot Pool:	249
Quorum:	**79.92 % The Quorum has been reached**
Weighted Segment Vote:	74.47 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	70	1	39	0.75	13	0.25	1	17
2 - Segment 2.	11	0.8	5	0.5	3	0.3	1	2
3 - Segment 3.	57	1	35	0.778	10	0.222	3	9
4 - Segment 4.	10	0.9	6	0.6	3	0.3	1	0
5 - Segment 5.	46	1	25	0.735	9	0.265	2	10
6 - Segment 6.	30	1	17	0.773	5	0.227	3	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	9	0.6	3	0.3	3	0.3	0	3
9 - Segment 9.	8	0.3	3	0.3	0	0	2	3
10 - Segment 10.	8	0.7	7	0.7	0	0	0	1
Totals	**249**	**7.3**	**140**	**5.436**	**46**	**1.864**	**13**	**50**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips		
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Avista Corp.	Scott Kinney		
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	

1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Negative	View
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	E.ON U.S. LLC	Larry Monday		
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	Exelon Energy	John J. Blazekovich	Negative	View
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Albert Poire	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg		
1	ITC Transmission	Elizabeth Howell	Negative	View
1	JEA	Ted E Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Kissimmee Utility Authority	Joe B Watson		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	Rodney Hawkins	Affirmative	
1	Long Island Power Authority	Jonathan Appelbaum	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Manuel Couto		
1	New York Power Authority	Ralph Rufrano		
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Oncor Electric Delivery	Charles W. Jenkins		
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	PacifiCorp	Mark Sampson		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Public Utility District No. 2 of Grant County	Kyle M. Hussey	Affirmative	View
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Abstain	
1	SaskPower	Wayne Guttormson		
1	SCE&G	Henry Delk, Jr.	Negative	View
1	Seattle City Light	Pawel Krupa	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Negative	View
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Greg Tillitson	Abstain	

2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Bobby Kerley	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Negative	View
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Farmington	Linda R. Jacobson	Abstain	
3	City Public Service of San Antonio	Edwin Les Barrow		
3	Commonwealth Edison Co.	Stephen Lesniak	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr		
3	Entergy Services, Inc.	Matt Wolf	Abstain	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Muscatine Power & Water	John Bos	Affirmative	
3	New York Power Authority	Michael Lupo	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	John J. McCawley	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Negative	View
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	View
4	Consumers Energy	David Frank Ronk	Affirmative	

4	Detroit Edison Company	Daniel Herring	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Northern California Power Agency	Fred E. Young	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Negative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Chelan County Public Utility District #1	John Yale		
5	City of Tallahassee	Alan Gale	Negative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Consolidated Edison Co. of New York	Edwin E Thompson		
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Negative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Edison Mission Energy	Ellen Oswald		
5	Entergy Corporation	Stanley M Jaskot		
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Michigan Public Power Agency	James R. Nickel		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp Energy	David Godfrey	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Thomas Piascik	Negative	View
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	TransAlta Centralia Generation, LLC	Joanna Luong-Tran	Abstain	
5	Tri-State G & T Association Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	View
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
6	AEP Marketing	Edward P. Cox	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Chris Lyons	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Negative	View
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah		
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta		

6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Portland General Electric Co.	John Jamieson		
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	RRI Energy	Trent Carlson	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Southern California Edison Co.	Marcus V Lotto		
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	Dennis Neitzel	Dennis Neitzel		
8	Edward C Stein	Edward C Stein	Negative	View
8	James A Maenner	James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Network & Security Technologies	Nicholas Lauriat	Negative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
8	Wally Magda	Wally Magda	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	New York State Department of Public Service	Thomas G Dvorsky		
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	View
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren		

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Consideration of Comments on Initial Ballot — Interpretation - CIP-006 - Cyber Security — Physical Security of Cyber Security Assets (Project 2008-10)
Date of Initial Ballot: September 30, 2009 – October 12, 2009

Summary Consideration:

The interpretation drafting team thanks all who commented during the last posting of the revised interpretation for their interest and feedback. Commenters from the last posting of the revised interpretation provided constructive comments and concerns. The interpretation drafting team identified two general themes in the comments:

1. **Disagreement concerning whether wiring is a "Cyber Asset." Several commenters expressed concern that interpreting wiring within the definition of "Cyber Asset" expanded the requirements of the standard; and**
2. **That CIP-006-1, requirement R1.1 does not specifically discuss particular options that may be used as alternatives to a completely enclosed ("six-wall" border) and should not be addressed by this interpretation.**

In response to the comments received and reflective of the team's revisions to the interpretation, the interpretation drafting team responded as follows:

The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.

The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Edward P. Cox	AEP Marketing	6	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), AEP has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Brock Ondayko	AEP Service Corp.	5	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), AEP has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Jason L. Murray	Alberta Electric System Operator	2	Negative	The AESO agrees that use of encryption and other logical access control methods may be sufficient in some cases, however that is not what the standard calls for. Logical access controls cannot provide physical protection, and the standard clearly calls for physical protection. Thus, this interpretation would have the effect of changing the standard. Standards are not to be changed through an interpretation. If the standard needs to be changed, then the AESO recommends that a drafting team be assembled to propose changes to the standard requirements.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Negative	Wiring itself does not possess programmable intelligence, is not a cyber asset, and should not require the protection as detailed in CIP-006-1, R1. This level of protection will require entities to make considerable investments into atypical cable protection methods without a correpsonding gain in protection of the cyber assets within the ESP or the reliability of the Bulk Electric System.
Response: Thank you for your comment. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring. The drafting team has revised the interpretation.				

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	Requirement R1.1 does not specifically discuss wiring. However, the interpretation results in expanding this requirement.
Response: Thank you for your comment. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring. The drafting team has revised the interpretation.				
Paul B. Johnson	American Electric Power	1	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), AEP has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Raj Rana	American Electric Power	3	Negative	n reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), AEP has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Jason Shaver	American Transmission Company, LLC	1	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), ATC has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Neither Requirement R1.1 (CIP-006-1) nor Requirement 3 (CIP-002-1) specifically discuss or identify wiring as a cyber asset which would need protection within a six wall barrier.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Paul Rocha	CenterPoint Energy	1	Negative	Upon further review of the interpretation provided for CIP_006-1 - R1.1, CenterPoint Energy agrees with the concerns of American Electric Power (AEP). The first part of R1.1 requires that "all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. " Therefore, it is our conclusion that the interpretation includes reference to a condition that should not occur if the entity is to be in compliance with CIP_006-1 - R1.1. Specifically, the statement pertaining to "wiring within the Electronic Security Perimeter that is external to a Physical Security Perimeter,..." should not occur (according to the requirements of R.1.1) and adds a level of complexity to what components/assets are covered and what is expected for compliance.
Response: Thank you for your comment. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring. The drafting team has revised the interpretation.				
Daniel Herring	Detroit Edison Company	4	Negative	Detroit Edison's opinion is this interpretation is unnecessary and that protecting cabling between physical security perimeters fully contained within an otherwise adequately secured facility is that the cable is sufficiently protected following guidance provided by NIST for use in our nuclear plants.
Response: The IDT thanks you for your comment. While the team believes that this comment suggests a good practice, it believes that the comment is beyond the scope of the interpretation.				
Jalal (John) Babik	Dominion Resources, Inc.	3	Negative	Dominion cannot approve this interpretation without fully understanding what is meant by "Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				

Voter	Entity	Segment	Vote	Comment
Mike Garton	Dominion Resources, Inc.	5	Negative	Dominion cannot approve this interpretation without fully understanding what is meant by 'Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Louis S Slade	Dominion Resources, Inc.	6	Negative	Dominion cannot approve this interpretation without fully understanding what is meant by "Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
William L. Thompson	Dominion Virginia Power	1	Negative	Dominion cannot approve this interpretation without fully understanding what is meant by "Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Douglas E. Hils	Duke Energy Carolina	1	Negative	Thank you for the opportunity to vote on this interpretation. We think that the interpretation is unclear and believe that this issue is best addressed in a comprehensive manner in a revision to the CIP standards.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Walter Yeager	Duke Energy Carolina	6	Negative	Thank you for the opportunity to vote on this interpretation. We think that the interpretation is unclear and believe that this issue is best addressed in a comprehensive manner in a revision to the CIP standards."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is				

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relevant to the “alternative measures” question that is beyond the scope of this interpretation. The definition of “Cyber Asset” in the *NERC Glossary of Terms Used in Reliability Standards* includes “communication networks,” but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of “Cyber Asset,” Requirement R1 of CIP-006-1 does not apply to wiring.				
Edward C Stein	Edward C Stein	8	Negative	So you have a system where you can detect when someone has gained "unauthorized access" and you discover that someone has gained unauthorized access, does this mean that you have violated some Standard somewhere. In today's world where the use of the internet is required to exchange market and transmission data to RTOs, I believe that it is impossible to protect yourself from a hacker. The interpretation is politically correct but is does not prevent hacking.
Response: The drafting team thanks you for your comment. While the team appreciates your concern, it believes that this issue is beyond the scope of the interpretation.				
Kent Saathoff	Electric Reliability Council of Texas, Inc.	10	Affirmative	For clarity, we suggest that NERC add a comment in guidelines or FAQs to reflect that steel conduits are acceptable as a 6-wall enclosure for wiring.
Response: The drafting team thanks you for your comment. While the team appreciates your concern, it believes that this issue is beyond the scope of the interpretation.				
John J. Blazekovich	Exelon Energy	1	Negative	Exelon believes that this interpretation, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Requirement R1.1 does not specifically discuss wiring, nor does the requirement suggest options that can be used as alternatives to a completely enclosed ("six-wall") border. It is also not fully responsive to the interpretation request by limiting the response just to wiring.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the “alternative measures” question that is beyond the scope of this interpretation.				
Kim Warren	Independent Electricity System Operator	2	Negative	We reiterate our previous comment that although directionally the IESO is in favour of the intent of the interpretation, we believe the current interpretation wording may effectively modify the intention of the standard, which is inconsistent with NERC Reliability Standards Development Procedure. Whereas the standard clearly requires physical access control, the interpretation effectively relaxes and hence alters this requirement by permitting logical measures to control physical access. Although we believe the standard should be revised to allow alternative protective

Voter	Entity	Segment	Vote	Comment
				measures, that is not the issue being balloted. We believe revisions to CIP-006-1, Requirement R1.1 should be made in the future to specifically cater for logical measures to control physical access to the Critical Cyber Assets.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Elizabeth Howell	ITC Transmission	1	Negative	In reviewing the response that the SDT has provided to the Progress Energy Interpretation addressing Requirement R1.1 (specifically addressing security perimeter wiring), ITC has determined that the interpretation process, albeit inadvertently, resulted in expanding the requirements of the standard rather than interpreting the existing requirement. Neither Requirement R1.1 (CIP-006-1) nor Requirement 3 (CIP-002-1) specifically discuss or identify wiring as a cyber asset which would need protection within a six wall barrier.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	The FAQ developed along with the original CIP standards specifically state that the standards are not intended to address the wires between facilities. While we agree that the suggested interpretation is a good idea for a future improvement to the standard, the interpretation process is intended to clarify what the standard says as originally drafted, not what we would like the standard to say. In the response to comments from the initial ballot, the drafting team pointed out that the FAQ is a reference document and not enforceable. While we agree this is true, it does point out what the intent of the drafting team was when writing the requirements and is thus critical to interpreting the CIP standards. Q11 in the FAQ is clear that the drafting team did not intend to include wiring. The drafting team stated that the requirement only applies to assets that are not owned by the Responsible Entity and that the Q11 in the FAQ only addressed non-owned assets. First, we assume that the drafting team is referring to leasing by thae statement "assets that are not owned" even though leasing is one form of ownership. Second, leasing of communications cirucits is only one example given in the answer to Q11 in the FAQ. Thus, we can't conclude that Q11 does not apply to all communication circuits. If

Voter	Entity	Segment	Vote	Comment
				the drafting team wants to apply the standard to the wiring in the request for interpretation, they need to submit a SAR to modify the standard.
Response: Thank you for your comment. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring. The drafting team has revised the interpretation.				
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Negative	Comments from the last ballot of this interpretation clearly show a strongly diverse set of opinions on the subject. While the RFI response drating team has done a diligent job of responding to those comments, it is clear that there will still be a strong divide on the issue. PSEG agrees with CAL ISO's position that this interpretation should not be "....what should have been done," Southern Company's position the "....it actually reresents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice....," ISO New England's position that "....the interpretation adds requirements that are not already part of the Standard...." and PJM's position that: "....the interpretation adds requirements that are not already part of the Standard. EIP-006 describes the requirements for physical access controls. An interpretation of a standard should not be confused with "what should have been done." The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including an explicit reference to data in transit over communication links between discrete perimeters, the interpretation moves into an area which the standard intentionally does no address." PSEG believes that the only appropriate was to reach agreement on Progress Energy's question is to submit a SAR to address the issue via the standards approval process. If the team is unwilling to have the question settled by the SAR process, then, at a minimum,an appropriate implementation schedule must also be issued."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Thomas Piascik	PSEG Power LLC	5	Negative	Comments from the last ballot of this interpretation clearly show a strongly diverse set of opinions for the subject. While the RFI response drafting team has done a diligent job of responding to those comments, it is clear that there will still be a strong divide on the issue. PSEG agrees with CAL ISO's position that this interpretation should not be "...what should have been done.", Southern Company's

Voter	Entity	Segment	Vote	Comment
				position that "...it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice...", ISO New England's position that "...the interpretation adds requirements that are not already part of the Standard..." and PJM's position that: "...the interpretation adds requirements that are not already part of the standard. CIP-006-1 describes the requirements for physical access controls. An interpretation of a standard should not be confused with "what should have been done". The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including an explicit reference to data in transit over communications links between discrete perimeters, the interpretation moves into an area which the standard intentionally does not address." PSEG believes that the only appropriate way to have agreement of Progress Energy's question is submit a SAR to address the issue via the standards approval process. If the team is unwilling to have the question settled by the SAR process, then, at a minimum, an appropriate implementation schedule must also be issued
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Kenneth D. Brown	Public Service Electric and Gas Co.	1	Negative	Comments from the last ballot of this interpretation clearly show a strongly diverse set of opinions for the subject. While the RFI response drafting team has done a diligent job of responding to those comments, it is clear that there will still be a strong divide on the issue. PSE&G agrees with CAL ISO's position that this interpretation should not be "...what should have been done.", Southern Company's position that "...it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice...", ISO New England's position that "...the interpretation adds requirements that are not already part of the Standard..." and PJM's position that "...the interpretation adds requirements that are not already part of the standard. CIP-006-1 describes the requirements for physical access controls. An interpretation of a standard should not be confused with "what should have been done". The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including an explicit reference to data in transit over communications links between discrete perimeters, the interpretation moves into an area which the standard intentionally does not address." PSE&G

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				believes that the only appropriate way to have agreement of Progress Energy's question is submit a SAR to address the issue via the standards approval process. If the team is unwilling to have the question settled by the SAR process, then, at a minimum, an appropriate implementation schedule must also be issued.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Negative	"Comments from the last ballot of this interpretation clearly show a strongly diverse set of opinions for the subject. While the RFI response drafting team has done a diligent job of responding to those comments, it is clear that there will still be a strong divide on the issue. PSEG agrees with CAL ISO's position that this interpretation should not be "...what should have been done.", Southern Company's position that "...it actually represents an extension of the standards without sufficient discussion within the industry or comparison to acknowledged industry best practice...", ISO New England's position that "...the interpretation adds requirements that are not already part of the Standard..." and PJM's position that: "...the interpretation adds requirements that are not already part of the standard. CIP-006-1 describes the requirements for physical access controls. An interpretation of a standard should not be confused with "what should have been done". The NERC Standards development process says that an interpretation cannot modify a standard, only clarify its meaning. By including an explicit reference to data in transit over communications links between discrete perimeters, the interpretation moves into an area which the standard intentionally does not address." PSEG believes that the only appropriate way to have agreement of Progress Energy's question is submit a SAR to address the issue via the standards approval process. If the team is unwilling to have the question settled by the SAR process, then, at a minimum, an appropriate implementation schedule must also be issued."
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not				

Voter	Entity	Segment	Vote	Comment
explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
Kyle M. Hussey	Public Utility District No. 2 of Grant County	1	Affirmative	I agree with this interpretation. This clarifies that wiring can not only be secured through physical means but also logical.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, approved appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation.				
Henry Delk, Jr.	SCE&G	1	Negative	SCE&G does not think the interpetation adds enough clarity. The issue should be addressed during development of the next set of NERC CIP Standards.
Response: Thank you for the comment. The Interpretation Drafting Team has revised the interpretation so that it limits itself to the specific question about wiring, and other issues raised regarding CIP-006-1 will be addressed in future versions.				
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G does not think the interpretation adds enough clarity. The issue should be addressed during development of the next set of NERC CIP standards.
Response: Thank you for the comment. The Interpretation Drafting Team has revised the interpretation so that it limits itself to the specific question about wiring, and other issues raised regarding CIP-006-1 will be addressed in future versions.				
Martin Bauer	U.S. Bureau of Reclamation	5	Affirmative	While Reclamation agrees with the interpretation, it is contingent on the basis that no TFE is required when Alternative Measures are deployed.
Response: Thank you for the comment. The Interpretation Drafting Team has revised the interpretation so that consideration of alternative measures and whether a TFE is required are beyond the scope of this Request for Interpretation.				
Allen Klassen	Westar Energy	1	Negative	Do not agree with wire as a cyber asset
Response: Thank you for your comment. The drafting team agrees and has revised the interpretation.				

Voter	Entity	Segment	Vote	Comment
Linda Horn	Wisconsin Electric Power Co.	5	Negative	Wisconsin Electric is concerned with the use of the term "effective security". This does not identify what type of physical protection is equivalent to six wall borders. Does cabling protected by metallic conduit constitute effective security? Communication networks utilizing fiber optic cabling is very difficult to splice in a tap allowing unapproved logical access. Does fiber optic cable require the same protective measures as copper? There are still questions or clarification required.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	Wisconsin Electric is concerned with the use of the term "effective security". This does not identify what type of physical protection is equivalent to six wall borders. Does cabling protected by metallic conduit constitute effective security? Communication networks utilizing fiber optic cabling is very difficult to splice in a tap allowing unapproved logical access. Does fiber optic cable require the same protective measures as copper? There are still questions or clarification required.
Response: Thank you for the comment. The drafting team has determined that the interpretation must be limited to the question asked: whether CIP-006-1 R1 applies to the aspects of the wiring that comprises the ESP. The drafting team has revised the interpretation to be limited accordingly. The team furthermore acknowledges and notes that a different interpretation, appended to CIP-006-3c as appendix 3, is relevant to the "alternative measures" question that is beyond the scope of this interpretation. The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definiton of "Cyber Asset," Requirement R1 of CIP-006-1 does not apply to wiring.				

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:
Progress Energy requests a formal interpretation of CIP-006-1. R1.1.

In CIP_006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

The following revised interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the CIP Interpretation Drafting Team's Project 2008-10 Interpretation Drafting Team in response to industry comments received from the second initial ballot:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Revised Response:

CIP-006-1, Requirement R1.1 applies to "Cyber Assets," and the first test in determining whether it applies to wiring is to determine whether wiring is a "Cyber Asset."
The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," Requirement R1.1 of CIP-006-1 does not apply to wiring.

This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 3. The interpretation in CIP-006-3c, appendix 3, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:
Progress Energy requests a formal interpretation of CIP-006-1. R1.1.

In CIP_006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

The following revised interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the ~~Cyber Security Order 706 SAR drafting team~~CIP Interpretation Drafting Team's Project 2008-10 Interpretation Drafting Team in response to industry comments received from the second initial ballot:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Revised Response:

~~The definition of Cyber Asset in the *NERC Glossary of Terms Used in Reliability Standards* includes communication networks. Physical media (wiring) is a component of a communication network within an Electronic Security Perimeter, but the wiring itself is not a separate Cyber Asset.~~

~~The specific situation described by Progress Energy involves physically separate Critical Cyber Assets connected by wiring inside the Electronic Security Perimeter. Since the connective wiring is inside the Electronic Security Perimeter, Requirement R1.1 of CIP-006-1 applies.~~

~~CIP-006-1 R1.1 also provides: "Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets." For wiring within the Electronic Security Perimeter that is external to a Physical Security Perimeter, the alternative measures may be physical or logical, on the condition that they provide effective security, i.e., equivalent to or better than a completely enclosed ("six-wall") border: alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space; alternative logical control measures may include, but are not limited to data encryption, and/or circuit monitoring to detect unauthorized access or physical tampering.~~

CIP-006-1, Requirement R1.1 applies to "Cyber Assets," and the first test in determining whether it applies to wiring is to determine whether wiring is a "Cyber Asset."
The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," Requirement R1.1 of CIP-006-1 does not apply to wiring.

This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g, "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 3. The interpretation in CIP-006-3c, appendix 3, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).

Unofficial Comment Form for Interpretation of CIP-006-x for Progress Energy (Project 2008-10)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form to submit comments on the interpretation of CIP-006-x for Progress Energy (Project 2008-10). The electronic comment form must be completed by **November 21, 2011.**

Project Page

If you have questions please contact Steven Noess at steven.noess@nerc.net or by telephone at 404-446-9691.

Background Information

The last successive ballot to this interpretation closed on October 12, 2009. Since that date, a project team from the CIP Interpretation Drafting Team reviewed and responded to the comments received from the last successive ballot and made revisions to the interpretation. The project team revised the interpretation pursuant to NERC Guidelines for Interpretation Drafting Teams (available here).

The interpretation drafting team determined that the interpretation must limit itself to the question asked: whether CIP-006-1, Requirement R1.1, applies to the aspects of wiring that comprises the ESP. The interpretation drafting team revised the interpretation from the last successive ballot accordingly.

The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but the interpretation drafting team determined that it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," the interpretation drafting team interpreted that Requirement R1.1 of CIP-006-1 does not apply to wiring.

The team furthermore acknowledges and notes in its revised interpretation that a different interpretation, appended to CIP-006-3c as appendix 3, applies to the "alternative measures" question "where a completely enclosed ('six-wall') border cannot be established" for "Cyber Assets within an Electronic Security Perimeter." The interpretation drafting team has determined that such analysis is beyond the scope of this interpretation. CIP-006-1 R1.1 applies to "Cyber Assets" and this interpretation is limited to whether wiring is a "Cyber Asset." A secondary analysis of "acceptable alternative measures where a completely enclosed ('six-wall') border cannot be established" does not apply.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

Please review the request for an interpretation, the associated standard, and the draft interpretation and then answer the following questions.

1. The NERC Board of Trustees indicated that the interpretation process **should not** be used to address requests for a decision on **"how"** a reliability standard applies to a registered entity's particular facts and circumstances. Do you believe this request for an interpretation is asking for clarity on the meaning of a requirement or clarity on the application of a requirement?

   ☐ The request is asking for clarity on the **meaning** of a requirement.

☐ The request is asking for clarity on the **application** of a requirement.

Comments:

2. The NERC Board of Trustees indicated that in deciding whether or not to approve a proposed interpretation, it will use a standard of strict construction and not seek to expand the reach of the standard to correct a perceived gap or deficiency in the standard. Do you believe this interpretation expands the reach of the standard?

   ☐ The interpretation **expands** the reach of the standard.

   ☐ The interpretation **does not expand** the reach of the standard.

   Comments:

3. Do you agree with this interpretation? If not, why not.

   ☐ Yes

   ☐ No

   Comments:

4. Are there any other comments you would like to add that haven't been covered in the previous questions, please add them here.

   Comments:

A. Introduction

1. Title: Cyber Security — Physical Security of Critical Cyber Assets

2. Number: CIP-006-3c

3. Purpose: Standard CIP-006-3 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-006-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Interchange Authority

4.1.4 Transmission Service Provider

4.1.5 Transmission Owner

4.1.6 Transmission Operator

4.1.7 Generator Owner

4.1.8 Generator Operator

4.1.9 Load Serving Entity

4.1.10 NERC

4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-006-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.

R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.

R1.6. A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:

R1.6.1. Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.

R1.6.2. Continuous escorted access of visitors within the Physical Security Perimeter.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-3. One or more of the following monitoring methods shall be used:

- Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.

R7. Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not make exceptions in its cyber security policy to the creation, documentation, or maintenance of a physical security plan.

1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-3 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Replaced the RRO with RE as a responsible entity. Modified CIP-006-1 Requirement R1 to clarify that a physical security plan to protect Critical Cyber Assets must be documented, maintained, implemented, and approved by the senior manager. Revised the wording in R1.2 to identify all "physical" access points. Added Requirement R2 to CIP-006-2 to clarify the requirement to safeguard the Physical Access Control Systems and exclude hardware at the Physical Security Perimeter access point, such as electronic lock control mechanisms and badge readers from the requirement. Requirement R2.1 requires the Responsible Entity to protect the Physical Access Control Systems from unauthorized access. CIP-006-1 Requirement R1.8 was moved to become CIP-006-2 Requirement R2.2. Added Requirement R3 to CIP-006-2, clarifying the requirement for Electronic Access Control Systems to be safeguarded within an identified Physical Security Perimeter. The sub requirements of CIP-006-2 Requirements R4, R5, and R6 were changed from formal requirements to bulleted lists of options consistent with the intent of the requirements. Changed the Compliance Monitor to Compliance Enforcement Authority.	
3		Updated version numbers from -2 to -3 Revised Requirement 1.6 to add a Visitor Control program component to the Physical Security Plan, in response to FERC order issued September 30, 2009. In Requirement R7, the term "Responsible Entity" was capitalized.	
	11/18/2009	Updated Requirements R1.6.1 and R1.6.2 to be responsive to FERC Order RD09-7	
3	12/16/09	Approved by NERC Board of Trustees	Update
1a	Board approved 02/12/ 2008	Interpretation of R1 and Additional Compliance Information Section 1.4.4 (Appendix 1)	Interpretation (Project 2007-27)
1b/2b	Board approved 08/05/2009	Interpretation of R4 (Appendix 2)	Interpretation (Project 2008-15)
3c	Board approved 02/16/2010	Interpretation of R1 and R1.1 (Appendix 3)	Interpretation (Project 2009-13)

Appendix 1

Interpretation of Requirement R1.1.

Request: *Are dial-up RTUs that use non-routable protocols and have dial-up access required to have a six-wall perimeters or are they exempted from CIP-006-1 and required to have only electronic security perimeters? This has a direct impact on how any identified RTUs will be physically secured.*

Interpretation:

Dial-up assets are Critical Cyber Assets, assuming they meet the criteria in CIP-002-1, and they must reside within an Electronic Security Perimeter. However, physical security control over a critical cyber asset is not required if that asset does not have a routable protocol. Since there is minimal risk of compromising other critical cyber assets dial-up devices such as Remote Terminals Units that do not use routable protocols are not required to be enclosed within a "six-wall" border.

CIP-006-1 — Requirement 1.1 requires a Responsible Entity to have a physical security plan that stipulate cyber assets that are within the Electronic Security Perimeter also be within a Physical Security Perimeter.

R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

CIP-006-1 — Additional Compliance Information 1.4.4 identifies dial-up accessible assets that use non-routable protocols as a special class of cyber assets that are not subject to the Physical Security Perimeter requirement of this standard.

1.4. Additional Compliance Information

1.4.4 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006 for that single access point at the dial-up device.

Appendix 2

The following interpretation of CIP-006-1a — Cyber Security — Physical Security of Critical Cyber Assets, Requirement R4 was developed by the standard drafting team assigned to Project 2008-14 (Cyber Security Violation Severity Levels) on October 23, 2008.

Request:

1. *For physical access control to cyber assets, does this include monitoring when an individual leaves the controlled access cyber area?*
2. *Does the term, "time of access" mean logging when the person entered the facility or does it mean logging the entry/exit time and "length" of time the person had access to the critical asset?*

Interpretation:

No, monitoring and logging of access are only required for ingress at this time. The term "time of access" refers to the time an authorized individual enters the physical security perimeter.

Requirement Number and Text of Requirement

R4. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

R4.1. Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.

R4.2. Video Recording: Electronic capture of video images of sufficient quality to determine identity.

R4.3. Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.

Appendix 3

Requirement Number and Text of Requirement
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following: R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.
Question
If a completely enclosed border cannot be created, what does the phrase, "to control physical access" require? Must the alternative measure be physical in nature? If so, must the physical barrier literally prevent physical access e.g. using concrete encased fiber, or can the alternative measure effectively mitigate the risks associated with physical access through cameras, motions sensors, or encryption? Does this requirement preclude the application of logical controls as an alternative measure in mitigating the risks of physical access to Critical Cyber Assets?
Response
For Electronic Security Perimeter wiring external to a Physical Security Perimeter, the drafting team interprets the Requirement R1.1 as not limited to measures that are "physical in nature." The alternative measures may be physical or logical, on the condition that they provide security equivalent or better to a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.

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Standards Announcement

Project 2008-10 Interpretation of CIP-006-x R1 for Progress Energy
Ballot Pool Forming October 12 – November 10, 2011
Formal Comment Period October 12 – November 21, 2011
Initial Ballot Window Open November 11 – 21, 2011

Project Webpage

An interpretation of CIP-006-x — Physical Security of Critical Cyber Assets has been posted for a formal comment period through 8 p.m. Eastern on Thursday, November 21, 2011. A new ballot pool is being formed and is open through 8 a.m. Eastern on Thursday, November 10th (note that ballot pools close at 8:00 *in the morning*, while comment periods and ballots close at 8:00 *in the evening*). An initial ballot of the interpretation will take place from Friday, November 11th through Monday, November 21st.

Instructions for Joining the Ballot Pool for Project 2008-10

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot at the following page: Join

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2008-10_CIP-006-1_SB_in@nerc.com

Instructions for Commenting

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An initial ballot of the interpretation will begin on Friday, November 11th and will end at 8 p.m. Eastern on Monday, November 21, 2011.

Background

On April 2, 2008, clarification was requested by Progress Energy on CIP-006-1, specifically on whether Electronic Security Perimeter wiring external to a Physical Security Perimeter must be protected within a six-wall boundary.

Initial ballots ended on August 16, 2008, and October 12, 2009. In November 2009, the NERC Board of Trustees issued guidance concerning interpretations, and development of more formal process for addressing interpretations consistent with BOT guidance, as well as the overall workload d priorities of the Project 2008-06 CIP standards drafting team, resulted in a delay in further processing.

In June 2011, the Standards Committee established and appointed members for a standing CIP Interpretation Drafting Team to process the CIP-related interpretations that remain outstanding, including Project 2008-10. A new project team was formed for this interpretation from the CIP Interpretation Drafting Team. In developing the revised interpretation for this successive ballot, the team considered and discussed FERC Order No. 706 and subsequent versions of the CIP standards. In addition, since the previous versions of this interpretation were posted, the Standards Committee has published Guidelines for Interpretation Drafting Teams that were applied by the CIP Interpretation Drafting team.

Additional information on Project 2008-10 is available on the project webpage. Additional information on the activities of the CIP Interpretation Drafting Team is available on the team's webpage.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2008-10 Interpretation of CIP-006-x R1 for Progress Energy

Successive Ballot Results

Now Available

A successive ballot of an interpretation of CIP-006-x — Physical Security of Critical Cyber Assets for Progress Energy concluded on November 21 2011. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results.

Quorum: 83.53%

Approval: 95.99%

Next Steps

The drafting team will consider all comments received and determine whether to make additional changes to the interpretation. If the drafting team decides to make additional changes to the interpretation to address stakeholder feedback from the formal comment period and ballot, the team will post the revised interpretation, along with its consideration of comments, for a parallel comment period and successive ballot. If the drafting team decides that no substantive changes are required to address stakeholder feedback, the team will post the interpretation and consideration of comments for a recirculation ballot.

Background

On April 2, 2008, clarification was requested by Progress Energy on CIP-006-1, specifically on whether Electronic Security Perimeter wiring external to a Physical Security Perimeter must be protected within a six-wall boundary.

Initial ballots ended on August 16, 2008, and October 12, 2009. In November 2009, the NERC Board of Trustees issued guidance concerning interpretations, and development of more formal process for addressing interpretations consistent with BOT guidance, as well as the overall workload d priorities of the Project 2008-06 CIP standards drafting team, resulted in a delay in further processing.

In June 2011, the Standards Committee established and appointed members for a standing CIP Interpretation Drafting Team to process the CIP-related interpretations that remain outstanding, including Project 2008-10. A new project team was formed for this interpretation from the CIP Interpretation Drafting Team. In developing the revised interpretation for this successive ballot, the team considered and discussed FERC Order No. 706 and subsequent versions of the CIP standards. In addition, since the previous versions of this interpretation were posted, the Standards Committee has

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Ballot Results	
Ballot Name:	Project 2008-10 Interpretation CIP-006-1 Progress Energy Successive Ballot_in
Ballot Period:	11/11/2011 - 11/21/2011
Ballot Type:	Initial
Total # Votes:	279
Total Ballot Pool:	334
Quorum:	**83.53 % The Quorum has been reached**
Weighted Segment Vote:	95.99 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	88	1	63	0.94	4	0.06	8	13
2 - Segment 2.	10	0.5	5	0.5	0	0	2	3
3 - Segment 3.	78	1	57	1	0	0	9	12
4 - Segment 4.	25	1	16	1	0	0	4	5
5 - Segment 5.	70	1	46	0.979	1	0.021	9	14
6 - Segment 6.	46	1	31	0.912	3	0.088	6	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	6	0.6	0	0	0	2
9 - Segment 9.	1	0.1	1	0.1	0	0	0	0
10 - Segment 10.	8	0.5	4	0.4	1	0.1	3	0
Totals	**334**	**6.7**	**229**	**6.431**	**9**	**0.269**	**41**	**55**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil		
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson		
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid	Saurabh Saksena		
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff		
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	PacifiCorp	Ryan Millard	Affirmative	
1	PECO Energy	Ronald Schloendorn		
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 2 of Grant County	Kyle M. Hussey	Affirmative	View
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	

1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Negative	View
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	View
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning		
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Arkansas Electric Cooperative Corporation	Philip Huff	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Ralph J Schulte	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	CJ Ingersoll	Affirmative	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	

3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	Mississippi Power	Jeff Franklin	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Oregon Trail Electric Cooperative	ned ratterman		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Clallam County	David Proebstel		
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	View
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	View
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	

5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	View
5	Edison Mission Energy	Ellen Oswald	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Michael Korchynsky	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino		
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Abstain	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Mississippi Electric Power Association	Jerry W Johnson	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	

5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	ACES Power Marketing	Jason L Marshall	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Abstain	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	New York Power Authority	William Palazzo		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Negative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Negative	View
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	View
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Network & Security Technologies	Nicholas Lauriat	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Negative	View
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Consideration of Comments

Interpretation of CIP-006-x for Progress Energy (Project 2008-10)

The CIP-006-x for Progress Energy Drafting Team thanks all commenters who submitted comments on the interpretation for CIP-006-x for Progress Energy (Project 2008-10). These standards were posted for a 45-day public comment period from October 12, 2011 through November 21, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 17 sets of comments, including comments from approximately 56 different people from approximately 31 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Project2008-10_CIP-006_Interpretation_Progress.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. The NERC Board of Trustees indicated that the interpretation process should not be used to address requests for a decision on "how" a reliability standard applies to a registered entity's particular facts and circumstances. Do you believe this request for an interpretation is asking for clarity on the meaning of a requirement or clarity on the application of a requirement? ..... *X*
2. The NERC Board of Trustees indicated that in deciding whether or not to approve a proposed interpretation, it will use a standard of strict construction and not seek to expand the reach of the standard to correct a perceived gap or deficiency in the standard. Do you believe this interpretation expands the reach of the standard? .... *X*
3. Do you agree with this interpretation? If not, why not. .... *X*
4. Are there any other comments you would like to add that haven't been covered in the previous questions, please add them here. .... *X*

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kevin Perry		SPP	10
2.	Shon Austin		SPP	10
3.	Ron Ciesiel		SPP	10

2.	Group	Connie Lowe	Electric Market Policy, Information Technology Risk Management	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Dodson		RFC	1
2.	Sean Iseminger		SERC	5
3.	Mike Garton		NPCC	5
4.	Michael Gildea		MRO	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
5. Louis Slade		RFC 6										
6. Michael Crowley		SERC 3										
3. Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC	8
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Chantel Haswell	FPL Group, Inc.		5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy Macdonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

4. Group	Nick Wehner	ACES Power Marketing Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1. James Jones		Arizona Electric Power Cooperative/Southwest Transmission Company	WECC 1, 4, 5										
5.	Group	Steve Diebold	Kansas City Power & Light	X		X		X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Michael Gammon	KCPL	SPP	1, 3, 5, 6									
2.	Scott Harris	KCPL	SPP	1, 3, 5, 6									
3.	Dean Larson	KCPL	SPP	1, 3, 5, 6									
4.	Bob Beachy	KCPL	SPP	1, 3, 5, 6									
5.	Brett Holland	KCPL	SPP	1, 3, 5, 6									
6.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
7.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
8.	Individual	Michael Falvo	Independent Electricity System Operator		X								
9.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
10.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Anthony Jablonski	ReliabilityFirst										X
13.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
14.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
15.	Individual	Chris Higgins / Forrest Krigbaum & BPA CIP Team	Bonneville Power Administration	X		X		X	X				
16.	Individual	Rebecca Moore Darrah	MISO		X								
17.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

1. **The NERC Board of Trustees indicated that the interpretation process should not be used to address requests for a decision on "how" a reliability standard applies to a registered entity's particular facts and circumstances. Do you believe this request for an interpretation is asking for clarity on the meaning of a requirement or clarity on the application of a requirement?**

Summary Consideration:

Many commenters noted the request for interpretation is asking for clarity on the application of a requirement, while others noted the request for interpretation is asking for clarity on the meaning of a requirement. In general, the Interpretation Drafting Team ("IDT") agrees the Request for Interpretation ("RFI") asks in part for clarity on the application of the requirement ("*Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP*"). The IDT notes, however, that whether the requirement applies requires clarity on the meaning of the requirement ("*It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary*"). The IDT interpreted that "wire" is not part of the definition of "Cyber Asset," and that CIP-006-3c, R1.1, only applies to Cyber Assets, which provides clarity on the meaning and the application of the requirement.

Organization	Yes or No	Question 1 Comment
Kansas City Power & Light	The request is asking for clarity on the application of a requirement.	In this instance the request is asking for clarity in the application of the requirement, however, the interpretation response involved both the meaning of requirement CIP-002-1, R3 and the application of that meaning with CIP-006-1, R1.1.
Response: Thank you for your response. The IDT agrees the RFI appears to ask, in part, for clarity on the application of the requirement to a particular circumstance; however, the RFI also asks for clarity on the meaning of the requirement.		
ReliabilityFirst	The request is asking for clarity on the application	The last sentence of the Request for Interpretation reads (emphasis added): Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP. The meaning of the requirement appears to be reasonably clear. Progress

Organization	Yes or No	Question 1 Comment
	of a requirement.	Energy is requesting a determination of how to apply the requirement to a specific situation.
Response: Thank you for your response; the IDT agrees. The IDT agrees the RFI appears to ask, in part, for clarity on the application of the requirement to a particular circumstance; however, the RFI also asks for clarity on the meaning of the requirement.		
Southern Company	The request is asking for clarity on the application of a requirement.	The request specifically asks about the applicability of wiring.
Response: Thank you for your response; the IDT agrees. The IDT agrees the RFI appears to ask, in part, for clarity on the application of the requirement to a particular circumstance; however, the RFI also asks for clarity on the meaning of the requirement.		
Xcel Energy	The request is asking for clarity on the meaning of a requirement.	This request is defining what is considered a Critical Asset and not how to protect the Critical Assets.
Response: Thank you for the comment. The IDT agrees the interpretation provides clarity on the meaning of the requirement by clarifying that wire is not a Cyber Asset.		
Independent Electricity System Operator	The request is asking for clarity on the application	

Organization	Yes or No	Question 1 Comment
	of a requirement.	
Oncor Electric Delivery Company LLC	The request is asking for clarity on the application of a requirement.	
Southwest Power Pool Regional Entity	The request is asking for clarity on the meaning of a requirement.	
Electric Market Policy, Information Technology Risk Management	The request is asking for clarity on the meaning of a requirement.	
Northeast Power Coordinating Council	The request is asking for clarity on the meaning of a requirement.	
ACES Power Marketing Standards Collaborators	The request is asking for clarity on the	

Organization	Yes or No	Question 1 Comment
	meaning of a requirement.	
Manitoba Hydro	The request is asking for clarity on the meaning of a requirement.	
Northeast Utilities	The request is asking for clarity on the meaning of a requirement.	
Duke Energy	The request is asking for clarity on the meaning of a requirement.	
American Electric Power	The request is asking for clarity on the meaning of a requirement.	
American Transsmission Company, LLC	The request is asking for clarity on the meaning of a	

Organization	Yes or No	Question 1 Comment
	requirement.	
Bonneville Power Administration		
MISO		

2. The NERC Board of Trustees indicated that in deciding whether or not to approve a proposed interpretation, it will use a standard of strict construction and not seek to expand the reach of the standard to correct a perceived gap or deficiency in the standard. Do you believe this interpretation expands the reach of the standard?

Summary Consideration:

Most balloters agree the interpretation does not expand the reach of the standard. However, one commenter expressed concern that the interpretation restricts the reach of the standard. In general, the IDT does not share this view, and notes that it must follow the guidelines set forth in the Guidelines for Interpretation Drafting Teams (available at: http://www.nerc.com/files/Guidelines_for_Interpretation_Drafting_Teams_Approved_April_2011.pdf). The IDT considered the requirement language in the standard as written in order to provide clarity on the meaning of the standard, and the IDT believes that the meaning of the standard informs the proper reach of the standard.

Organization	Yes or No	Question 2 Comment
ReliabilityFirst	The interpretation does not expand the reach of the standard.	However, this interpretation greatly restricts the reach of CIP-006-3c R1.
Response: Thank you for your comment. While the IDT appreciates this concern, it disagrees that the interpretation restricts the reach of the standard. Rather, the purpose of the interpretation is to consider the language as written, within the Guidelines for Interpretation Drafting Teams, and to provide clarity on the meaning of the standard.		
Xcel Energy	The interpretation does not expand the reach of the standard.	The interpretation provided defines more clearly what should be included in the scope of standard.

Organization	Yes or No	Question 2 Comment
Response: Thank you for the comment, The IDT appreciates that its analysis of the language provides clarity.		
Southwest Power Pool Regional Entity	The interpretation does not expand the reach of the standard.	
Electric Market Policy, Information Technology Risk Management	The interpretation does not expand the reach of the standard.	
Northeast Power Coordinating Council	The interpretation does not expand the reach of the standard.	
ACES Power Marketing Standards Collaborators	The interpretation does not expand the reach of the standard.	

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	The interpretation does not expand the reach of the standard.	
Southern Company	The interpretation does not expand the reach of the standard.	
Manitoba Hydro	The interpretation does not expand the reach of the standard.	
Independent Electricity System Operator	The interpretation does not expand the reach of the standard.	
Northeast Utilities	The interpretation	

Organization	Yes or No	Question 2 Comment
	does not expand the reach of the standard.	
Duke Energy	The interpretation does not expand the reach of the standard.	
American Electric Power	The interpretation does not expand the reach of the standard.	
Oncor Electric Delivery Company LLC	The interpretation does not expand the reach of the standard.	
American Transmission Company, LLC	The interpretation does not expand the reach of the	

Organization	Yes or No	Question 2 Comment
	standard.	
MISO	The interpretation does not expand the reach of the standard.	
Bonneville Power Administration		

3. Do you agree with this interpretation? If not, why not.

Summary Consideration:

By overwhelming majority, most balloters agreed with the IDT's interpretation. However, there were some important minority viewpoints that the team considered. Almost universally, the viewpoints and concerns raised by commenters who did not agree with the interpretation were previously evaluated and considered in some manner during the development of the interpretation. In the responses that follow, and summarized here, the IDT explains the team's conclusions in developing the interpretation and how the team considered the comments. The team appreciated all of the comments and thanks participants for their input.

First, some commenters expressed concern that this interpretation conflicts with the interpretation in Appendix 1 of CIP-006-3c (see clarifying discussion, below, regarding usage of "Appendix 1" v. "Appendix 3" in reference to the interpretation developed by Project 2009-13). The IDT disagrees that this interpretation conflicts with Appendix 1, because there may be other scenarios beyond wiring for which Appendix 1 applies. Appendix 1 and this interpretation address different questions. This interpretation addresses whether wire is a Cyber Asset and Appendix 1 addresses alternative measures to a "six-wall" border for Cyber Assets.

Another commenter was concerned the interpretation would change the way standards are read and weaken the standard, but the IDT notes in its response the distinction between lists separated by "but not limited to" and the definition of "Cyber Asset," which is the subject of this interpretation. Furthermore, the IDT respectfully disagrees the interpretation weakens the standard, because the purpose of the interpretation is to consider the language as written, within the Guidelines for Interpretation Drafting Teams, and to provide clarity on the meaning of the standard.

In response to a comment that wire is a transport medium necessitating classification as a Cyber Asset and that wiring is an essential component of a network, the IDT explains that it respectfully disagrees on the bases that a transport medium is not the same as a communication network (and therefore not a Cyber Asset to which the requirement applies) and that essentiality of a component is not the criteria for application of the requirement in question.

One commenter noted the interpretation incorrectly referenced Appendix 3 of CIP-006-3c, and that the correct reference should be Appendix 1. In its interpretation, the IDT referred to the interpretation developed by Project 2009-13. That interpretation is now posted on the NERC Web site as Appendix 1 of CIP-006-3c; however, the interpretation developed by Project 2009-13 was Appendix 3 in the version of CIP-006-3c that accompanied the information for this project's (Project 2008-10) formal comment and successive ballot period materials. The numbering of the appendices in CIP-006-3c changed in September, 2011 (but not the content). The IDT agrees with the commenter that the reference should be corrected to refer to the latest posted version of CIP-006-3c, which is Appendix 1. Additionally, the IDT believes that it is clear from the context of the interpretation and the comments received that any references to "Appendix 3," both by commenters and the previously-posted version of this interpretation (Project 2008-10), refer to

the interpretation developed by Project 2009-13. In response to the comment, the IDT has changed the reference in the interpretation, which does not affect the substance of the interpretation. For purposes of these responses to comments, the IDT construes references to Appendix 1 and to Appendix 3 as references to the interpretation developed by Project 2009-13. As such, it is using the corrected reference to Appendix 1 in its responses for consistency, even if the commenter references Appendix 3.

Organization	Yes or No	Question 3 Comment
ReliabilityFirst	No	1. This interpretation is in direct conflict with Appendix 3 of CIP-006-3c. If wiring is not considered part of a network, then Appendix 3 of CIP-006-3c is not needed.2. This interpretation changes the way standards are read, and will require every reliability standard to be reviewed and possibly re-written. For example, FAC-008-3 R2.4.1 gives the scope as including, but not limited to, six types of equipment. If this interpretation passes, then FAC-008-3 will be read prescriptively. Any device not specifically listed will be out of scope for the requirement.3. From a cyber security perspective, this interpretation fatally weakens the protections of CIP-006-3c and CIP-005-3a. Running network cable outside of a Physical Security Perimeter without some form of compensating measure is exposing the data from within an ESP to possible compromise and attack.

Response: Thank you for your comments. The IDT discussed and evaluated all of these concerns in its deliberations of developing the interpretation. The following explanations, which correspond with the numbering of your comments, discuss the IDT's consideration of your concerns:

1) **The IDT disagrees that this interpretation is in direct conflict with Appendix 1 of CIP-006-3c (See explanation of "Appendix 1" v. "Appendix 3" usage in the Summary Consideration to Question 3, above). There may be other scenarios beyond wiring for which Appendix 1 applies.**
2) **The IDT respectfully disagrees. In the example given of FAC-008-3, and in many other standards' requirements, the language includes the phrase, "but not limited to," which specifically precludes a prescriptive reading of the enumerated items. Furthermore, the IDT is not changing the scope of what is enumerated in determining what is a Cyber Asset; instead, it is clarifying that "wire" is not explicitly included within the meaning of "communication network," which is enumerated in the language of the definition of "Cyber Asset."**
3) **While the IDT appreciates this concern, it disagrees that the interpretation weakens the protections of CIP-006 and CIP-005**

Organization	Yes or No	Question 3 Comment
because it is not contrary to any requirement to protect data.		
Southwest Power Pool Regional Entity	No	SPP RE does not agree with this interpretation for two reasons. 1. The NERC Glossary defines a Cyber Asset as "Programmable electronic devices and communication networks including hardware, software, and data." The wire is the transport medium for the data, and data is a cyber asset. CIP-006-3 R1.1 requires data to be protected; to protect the data, the wire must also be protected. 2. Wiring can be viewed as an essential component of the hardware comprising a network, further supporting the need to protect the wiring.
Response: The IDT thanks you for your comments. The IDT considered and evaluated these concerns in its deliberations. The following explanations, which correspond with the numbering of your comments, discuss the IDT's consideration of your concerns: **1. The IDT determined that wire is an underlying component of a Cyber Asset, much like air is the transport medium in a wireless network. However, wire or air itself is not a "communication network" (and therefore not a Cyber Asset), which is not contrary to CIP-006-3c, R1.1's requirement to protect data.** **The IDT appreciates this concern, but notes that it is outside the scope of the language of the definition of "Cyber Asset," and CIP-006-3c, R1.1's application is limited to Cyber Assets. Power and facilities are also essential components, but whether they are essential is not the criteria for application of CIP-006-3c, R1.1, which is the subject of this interpretation. The purpose of the interpretation is to consider the language as written, within the Guidelines for Interpretation Drafting Teams, and to provide clarity on the meaning of the standard.**		
Kansas City Power & Light	No	The question raised by Progress Energy is not clear enough for an appropriate interpretive response. As a result, the interpretive response may be including assumptions that were not stated in the question posed by Progress Energy. At any rate, it is recommended that Progress Energy be afforded the opportunity to resubmit their question with additional information and circumstances regarding the communications mediums leaving the Physical Security Perimeter under consideration.

Organization	Yes or No	Question 3 Comment
Response: The IDT thanks you for your comment, but it disagrees that the request for interpretation is not clear enough for an interpretive response. The IDT believes it has provided clarity to the meaning of the requirement through its analysis.		
Southern Company	Yes	However, the interpretation incorrectly refers to Appendix 3 of CIP-006-3c. The language should be corrected to refer to Appendix 1 of CIP-006-3c.
Response: The IDT thanks you for this comment. In its reference to "Appendix 3," the IDT referred to the interpretation developed by Project 2009-13. That interpretation is now posted as Appendix 1 of CIP-006-3c; however, the interpretation developed by Project 2009-13 was labeled as Appendix 3 in the version of CIP-006-3c that accompanied the information for this project's (Project 2008-10) formal comment and successive ballot period materials on the Project 2008-10 project page. The numbering of the appendices in CIP-006-3c changed in September, 2011 (but not the content). The IDT agrees with the commenter that the reference should be corrected to refer to the latest posted version of CIP-006-3c, which is Appendix 1. Additionally, the IDT believes that it is clear from the context of the comments received that references to "Appendix 3," both by commenters and the previously-posted version of this interpretation (Project 2008-10), refer to the interpretation developed by Project 2009-13. In response, the IDT has changed the reference in the interpretation, which does not affect the substance of the interpretation.		
Electric Market Policy, Information Technology Risk Management	Yes	
Northeast Power Coordinating Council	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Manitoba Hydro	Yes	
Independent Electricity	Yes	

Organization	Yes or No	Question 3 Comment
System Operator		
Northeast Utilities	Yes	
Duke Energy	Yes	
American Electric Power	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transsmission Company, LLC	Yes	
MISO	Yes	
Xcel Energy	Yes	
Bonneville Power Administration		

4. Are there any other comments you would like to add that haven't been covered in the previous questions, please add them here.

Summary Consideration:

Some commenters expressed concern about the distinction between Appendix 1 of CIP-006-3c and this interpretation (See explanation of "Appendix 1" v. "Appendix 3" usage in reference to Project 2009-13 in the Summary Consideration to Question 3, above). This interpretation is distinct because it only addresses whether wire is a "Cyber Asset." The IDT notes that, while Appendix 1 may have used "wire" as an example, Appendix 1 applies only upon a determination that something is a Cyber Asset. This interpretation clarifies that wiring is not a Cyber Asset.

One commenter thought the interpretation should have been an initial ballot, but the IDT notes that a successive ballot is appropriate under the current NERC Standard Processes Manual when making a substantive change to the previously-posted interpretation.

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration		BPA thanks you for the opportunity to comment on Project 2008-10 Interpretation of CIP-006-1 R1 for Progress Energy. BPA has no comments or concerns at this time.
Response: Thank you for your participation		
MISO		In general, the Midwest Independent Transmission System Operator (the "MISO") supports the revised interpretation of CIP-006-1, Requirement R1.1 (the "2008-10 Interpretation") developed by the CIP Interpretation Drafting Team (the "IDT"). In particular, MISO agrees with the IDT that wiring does not meet the definition of "Cyber Asset" in the NERC Glossary of Terms Used in Reliability Standards and that Requirement R1.1 therefore does not apply to wiring. MISO is concerned, however, that there is an inconsistency between the 2008-10 Interpretation and the interpretation in CIP-006-3c, appendix 3 ("Appendix 3"). Appendix 3 states that "[f]or Electronic Security Perimeter wiring external to a Physical Security Perimeter, the drafting team interprets [ ] Requirement R1.1 as not limited to measures that are 'physical in nature'" (emphasis added). This language implies that wiring is subject to Requirement R1.1. The 2008-10 Interpretation, however, states unambiguously that

Organization	Yes or No	Question 4 Comment
		wiring is not a Cyber Asset and is not subject to Requirement R1.1. The IDT is clearly aware of this inconsistency, as it included the following language in the interpretation:This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 3. The interpretation in CIP-006-3c, appendix 3c, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).This limitation of the 2008-10 Interpretation does not, however, resolve the identified inconsistency because Appendix 3 explicitly addresses wiring, which means it is not "distinct" from the 2008-10 Interpretation. Thus, while MISO supports the approval of the 2008-10 Interpretation, MISO also urges the IDT to amend Appendix 3 or otherwise clarify that Appendix 3 does not apply to wiring.
Response: Thank you for your comment. The IDT disagrees that this interpretation is in direct conflict with Appendix 1 of CIP-006-3c (See explanation of "Appendix 1" v. "Appendix 3" usage in reference to Project 2009-13 in the Summary Consideration of Question 3, above). There may be other scenarios beyond wiring for which Appendix 1 applies. The purpose of the interpretation is to consider the language as written, within the Guidelines for Interpretation Drafting Teams, and to provide clarity on the meaning of the standard. The IDT notes that, while Appendix 1 may have used "wire" as an example, Appendix 1 applies only upon a determination that something is a Cyber Asset. This interpretation clarifies that wiring is not a Cyber Asset.		
ReliabilityFirst		This ballot should not be a successive ballot, but rather an initial ballot, as the text of the interpretation has been completely changed.
Response: The IDT thanks you for your comment, but notes that a successive ballot was called for pursuant to the NERC Standards Processes Manual. While the text completely changed, it was a substantive change necessitating a successive ballot.		
Southwest Power Pool Regional Entity		We disagree with the assertion: "This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 3. The interpretation in CIP-006-3c, appendix 3, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter

Organization	Yes or No	Question 4 Comment
		(ESP)."The interpretation in CIP-006-3C, Appendix 3 is directly applicable to Interpretation of CIP-006-1 Cyber Security - Physical Security of Critical Cyber Assets for Progress Energy. The interpretation found in Appendix 3 does provide for alternative means other than physical protection for instances in which physical protection is not technically feasible. Implementation of those alternative means addresses instances in which data must traverse beyond a traditional "six-wall" boundary.
Response: The IDT thanks you for your comment. This interpretation is distinct because it only addresses whether wire is a "Cyber Asset." The IDT notes that, while Appendix 1 may have used "wire" as an example, Appendix 1 applies only upon a determination that something is a Cyber Asset. This interpretation clarifies that wiring is not a Cyber Asset. There may be other scenarios beyond wiring for which Appendix 1 applies.		
Southern Company		We would seek guidance or direction on how this interpretation applies to all versions of the approved standards. If this guidance is already available, please include a preamble providing how the interpretation will apply to all approved versions of the CIP-006 standard (i.e. CIP versions 1 through 4).
Response: The IDT thanks you for your question. An approved interpretation will be applied as equally relevant to all prior and subsequent versions of the standard to the extent the language of the relevant requirement language is the same in substance. The IDT anticipates that this interpretation, subject to industry, NERC Board of Trustees, and FERC approval, will be equally applicable to CIP-006, Versions 1 through Version 4 (The IDT notes that Version 4 remains pending as of this response, and its answer here assumes approval as filed by NERC to FERC).		
Electric Market Policy, Information Technology Risk Management		
ACES Power Marketing Standards Collaborators		

Organization	Yes or No	Question 4 Comment
Manitoba Hydro		
Independent Electricity System Operator		
Northeast Utilities		
Duke Energy		
American Electric Power		
Oncor Electric Delivery Company LLC		
American Transsmission Company, LLC		
Xcel Energy		

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:
Progress Energy requests a formal interpretation of CIP-006-1. R1.1.

In CIP_006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

The following revised interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the CIP Interpretation Drafting Team's Project 2008-10 Interpretation Drafting Team in response to industry comments received from the second initial ballot:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Revised Response:

CIP-006-1, Requirement R1.1 applies to "Cyber Assets," and the first test in determining whether it applies to wiring is to determine whether wiring is a "Cyber Asset."
The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," Requirement R1.1 of CIP-006-1 does not apply to wiring.

This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix 1. The interpretation in CIP-006-3c, appendix 1, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets for Progress Energy

Request for Interpretation Received from Progress Energy on April 2, 2008:

Request:
Progress Energy requests a formal interpretation of CIP-006-1. R1.1.

In CIP_006-1, Requirement 1.1 states "Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets."

In CIP-005-1, Requirement 1 states "Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s)."

In CIP-002-1, Requirement 3 states "Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time interutility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

CIP-002-1 R3 defines Critical Cyber Assets as assets essential to the operation of Critical Asset and assets meeting one of the characteristics of R3.1, R3.2 or R3.3. It is unclear from the stated requirements the extent ESP wiring external to physical security perimeter must be protected within a six wall boundary. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.

CIP-006-1 Cyber Security – Physical Security of Critical Cyber Assets
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

The following revised interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets Requirement R1.1 was developed by the CIP Interpretation Drafting Team's Project 2008-10 Interpretation Drafting Team in response to industry comments received from the second initial ballot:

Interpretation of CIP-006-1 Requirement R1.1*: "…to ensure and document that all Cyber Assets within an Electronic Security Perimeter (ESP) also reside within an identified Physical Security Perimeter. Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the ESP.*

Revised Response:

CIP-006-1, Requirement R1.1 applies to "Cyber Assets," and the first test in determining whether it applies to wiring is to determine whether wiring is a "Cyber Asset."
The definition of "Cyber Asset" in the *NERC Glossary of Terms Used in Reliability Standards* includes "communication networks," but it does not explicitly include wiring or communication mediums in general. Since wiring is not included in the definition of "Cyber Asset," Requirement R1.1 of CIP-006-1 does not apply to wiring.

This interpretation is limited to whether Requirement R1.1 applies to a particular circumstance (e.g., "wiring"), which makes it distinct from the interpretation in CIP-006-3c, appendix ~~3~~1. The interpretation in CIP-006-3c, appendix ~~3~~1, only applies when a completely enclosed ("six-wall") border cannot be established for a "Cyber Asset" within an Electronic Security Perimeter (ESP).

A. Introduction

1. Title: Cyber Security — Physical Security of Critical Cyber Assets

2. Number: CIP-006-3c

3. Purpose: Standard CIP-006-3 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-006-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Interchange Authority

4.1.4 Transmission Service Provider

4.1.5 Transmission Owner

4.1.6 Transmission Operator

4.1.7 Generator Owner

4.1.8 Generator Operator

4.1.9 Load Serving Entity

4.1.10 NERC

4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-006-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

R1.2. Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.

R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

R1.4. Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.

R1.6. A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:

R1.6.1. Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.

R1.6.2. Continuous escorted access of visitors within the Physical Security Perimeter.

R1.7. Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Annual review of the physical security plan.

R2. Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:

R2.1. Be protected from unauthorized physical access.

R2.2. Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.

R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

R4. Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R5. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-3. One or more of the following monitoring methods shall be used:

- Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.

R6. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.

R7. Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.

R8. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:

R8.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R8.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.

R8.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

M1. The Responsible Entity shall make available the physical security plan as specified in Requirement R1 and documentation of the implementation, review and updating of the plan.

M2. The Responsible Entity shall make available documentation that the physical access control systems are protected as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation that the electronic access control systems are located within an identified Physical Security Perimeter as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation identifying the methods for monitoring physical access as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation identifying the methods for logging physical access as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation to show retention of access logs as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation to show its implementation of a physical security system maintenance and testing program as specified in Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entities.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documents other than those specified in Requirements R7 and R8.2 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 The Responsible Entity may not make exceptions in its cyber security policy to the creation, documentation, or maintenance of a physical security plan.

1.5.2 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006-3 for that single access point at the dial-up device.

2. Violation Severity Levels (Under development by the CIP VSL Drafting Team)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by NERC Board of Trustees	
1	January 18, 2008	FERC Order issued approving CIP-006-1	
	February 12, 2008	Interpretation of R1 and Additional Compliance Information Section 1.4.4 adopted by NERC Board of Trustees	Project 2007-27
2		Updated version number from -1 to -2 Modifications to remove extraneous information from the requirements, improve readability, and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.	Project 2008-06
2	May 6, 2009	Adopted by NERC Board of Trustees	
	August 5, 2009	Interpretation of R4 adopted by NERC Board of Trustees	Project 2008-15
2	September 30, 2009	FERC Order issued approving CIP-006-2	
3	November 18, 2009	Updated version number from -2 to -3 Revised Requirement 1.6 to add a Visitor Control program component to the Physical Security Plan, in response to FERC order issued September 30, 2009. In Requirement R7, the term "Responsible Entity" was capitalized. Updated Requirements R1.6.1 and R1.6.2 to be responsive to FERC Order RD09-7	Project 2009-21
3	December 16, 2009	Adopted by NERC Board of Trustees	
	February 16, 2010	Interpretation of R1 and R1.1 adopted by NERC Board of Trustees	Project 2009-13
3	March 31, 2010	FERC Order issued approving CIP-006-3	
2a/3a	July 15, 2010	FERC Order issued approving the Interpretation of R1 and R1.1. Updated version numbers from -2/-3 to -2a/-3a.	
4	January 24, 2011	Adopted by NERC Board of Trustees	
3c/4c	May 19, 2011	FERC Order issued approving two interpretations: 1) Interpretation of R1 and Additional Compliance Information Section 1.4.4; and 2) Interpretation of R4. Updated version number from -3/-4 to -3c/-4c.	

Appendix 1

Requirement Number and Text of Requirement
R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following: R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.
Question
If a completely enclosed border cannot be created, what does the phrase, "to control physical access" require? Must the alternative measure be physical in nature? If so, must the physical barrier literally prevent physical access e.g. using concrete encased fiber, or can the alternative measure effectively mitigate the risks associated with physical access through cameras, motions sensors, or encryption? Does this requirement preclude the application of logical controls as an alternative measure in mitigating the risks of physical access to Critical Cyber Assets?
Response
For Electronic Security Perimeter wiring external to a Physical Security Perimeter, the drafting team interprets the Requirement R1.1 as not limited to measures that are "physical in nature." The alternative measures may be physical or logical, on the condition that they provide security equivalent or better to a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.

Appendix 2

Interpretation of Requirement R1.1.

Request: *Are dial-up RTUs that use non-routable protocols and have dial-up access required to have a six-wall perimeters or are they exempted from CIP-006-1 and required to have only electronic security perimeters? This has a direct impact on how any identified RTUs will be physically secured.*

Interpretation:

Dial-up assets are Critical Cyber Assets, assuming they meet the criteria in CIP-002-1, and they must reside within an Electronic Security Perimeter. However, physical security control over a critical cyber asset is not required if that asset does not have a routable protocol. Since there is minimal risk of compromising other critical cyber assets dial-up devices such as Remote Terminals Units that do not use routable protocols are not required to be enclosed within a "six-wall" border.

CIP-006-1 — Requirement 1.1 requires a Responsible Entity to have a physical security plan that stipulate cyber assets that are within the Electronic Security Perimeter also be within a Physical Security Perimeter.

R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

CIP-006-1 — Additional Compliance Information 1.4.4 identifies dial-up accessible assets that use non-routable protocols as a special class of cyber assets that are not subject to the Physical Security Perimeter requirement of this standard.

1.4. Additional Compliance Information

1.4.4 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006 for that single access point at the dial-up device.

Appendix 3

The following interpretation of CIP-006-1a — Cyber Security — Physical Security of Critical Cyber Assets, Requirement R4 was developed by the standard drafting team assigned to Project 2008-14 (Cyber Security Violation Severity Levels) on October 23, 2008.

Request:

1. *For physical access control to cyber assets, does this include monitoring when an individual leaves the controlled access cyber area?*
2. *Does the term, "time of access" mean logging when the person entered the facility or does it mean logging the entry/exit time and "length" of time the person had access to the critical asset?*

Interpretation:

No, monitoring and logging of access are only required for ingress at this time. The term "time of access" refers to the time an authorized individual enters the physical security perimeter.

Requirement Number and Text of Requirement

R4. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

R4.1. Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.

R4.2. Video Recording: Electronic capture of video images of sufficient quality to determine identity.

R4.3. Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2008-10 Interpretation of CIP-006-x R1 for Progress Energy
Recirculation Ballot Window Open: December 9 - 19, 2011

Now Available

A recirculation ballot window is open for Project 2008-10 Interpretation of CIP-006-x R1 for Progress Energy from Friday, December 9, 2011 through 8 p.m. Eastern on Monday, December 19, 2011.

Since the initial ballot, the drafting team has considered all comments received during the formal comment period and successive ballot of the interpretation, and made no substantive changes to the interpretation. Only one change was made, to correct a reference to a prior interpretation of the same standard.

In its interpretation, the drafting team made a reference to a prior interpretation developed by Project 2009-13, which was Appendix 3 in the version of CIP-006-3c that accompanied the formal comment and successive ballot period materials. However, since that posting, the drafting team was made aware that the interpretation developed by Project 2009-13 is now posted as Appendix 1 of CIP-006-3c. The numbering of the appendices in CIP-006-3c changed in September 2011 (but not the content). The reference in this interpretation was updated to refer to the latest posted version of CIP-006-3c, which is Appendix 1.

Documents associated with this project, including clean and redline copies of the interpretation, the standard, and the drafting team's consideration of comments submitted during the parallel formal comment period and successive ballot that ended on November 21, 2011, have been posted on the project page.

Instructions for Balloting in the Recirculation Ballots

In a recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's last vote cast in the successive ballot that ended on November 21, 2011 will be carried over.

Members of the ballot pool associated with the interpretation may log in and submit their votes in the recirculation ballots from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

If the interpretation achieves ballot pool approval, they will be presented to the Board of Trustees for adoption and subsequently filed with regulators for approval.

Background

On April 2, 2008, clarification was requested by Progress Energy on CIP-006-1, specifically on whether Electronic Security Perimeter wiring external to a Physical Security Perimeter must be protected within a six-wall boundary.

Initial ballots ended on August 16, 2008, and October 12, 2009. In November 2009, the NERC Board of Trustees issued guidance concerning interpretations, and development of more formal process for addressing interpretations consistent with BOT guidance, as well as the overall workload d priorities of the Project 2008-06 CIP standards drafting team, resulted in a delay in further processing.
In June 2011, the Standards Committee established and appointed members for a standing CIP Interpretation Drafting Team to process the CIP-related interpretations that remain outstanding, including Project 2008-10. A new project team was formed for this interpretation from the CIP Interpretation Drafting Team. In developing the revised interpretation for this successive ballot, the team considered and discussed FERC Order No. 706 and subsequent versions of the CIP standards. In addition, since the previous versions of this interpretation were posted, the Standards Committee has published Guidelines for Interpretation Drafting Teams that were applied by the CIP Interpretation Drafting team.

Additional information on Project 2008-10 is available on the project webpage. Additional information on the activities of the CIP Interpretation Drafting Team is available on the team's webpage.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2008-10 Interpretation of CIP-006-x for Progress Energy

Recirculation Ballot Results

Now Available

A recirculation ballot of an interpretation of CIP-006-x Requirement R6 concluded on December 19, 2011. The interpretation was approved by the ballot pool. Voting statistics are listed below, and the Ballot Results webpage provides a link to the detailed initial ballot results.

Recirculation Ballot Results
Quorum: 88.02%
Approval: 96.04%

Next Steps
The interpretation will be presented to the NERC Board of Trustees for action, and if adopted, filed with regulatory authorities.

Background
On April 2, 2008, clarification was requested by Progress Energy on CIP-006-1, specifically on whether Electronic Security Perimeter wiring external to a Physical Security Perimeter must be protected within a six-wall boundary.

Initial ballots ended on August 16, 2008, and October 12, 2009. In November 2009, the NERC Board of Trustees issued guidance concerning interpretations, and development of more formal process for addressing interpretations consistent with BOT guidance, as well as the overall workload d priorities of the Project 2008-06 CIP standards drafting team, resulted in a delay in further processing.

In June 2011, the Standards Committee established and appointed members for a standing CIP Interpretation Drafting Team to process the CIP-related interpretations that remain outstanding, including Project 2008-10. A new project team was formed for this interpretation from the CIP Interpretation Drafting Team. In developing the revised interpretation for this successive ballot, the team considered and discussed FERC Order No. 706 and subsequent versions of the CIP standards. In addition, since the previous versions of this interpretation were posted, the Standards Committee has published Guidelines for Interpretation Drafting Teams that were applied by the CIP Interpretation Drafting team.

Additional information on Project 2008-10 is available on the project webpage. Additional information on the activities of the CIP Interpretation Drafting Team is available on the team's webpage.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2008-10 Interpretation CIP-006-1 Progress Energy Successive Ballot_rc
Ballot Period:	12/9/2011 - 12/19/2011
Ballot Type:	recirculation
Total # Votes:	294
Total Ballot Pool:	334
Quorum:	**88.02 % The Quorum has been reached**
Weighted Segment Vote:	96.04 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	88	1	67	0.931	5	0.069	8	8
2 - Segment 2.	10	0.6	6	0.6	0	0	2	2
3 - Segment 3.	78	1	61	1	0	0	7	10
4 - Segment 4.	25	1	16	1	0	0	5	4
5 - Segment 5.	70	1	49	1	0	0	10	11
6 - Segment 6.	46	1	33	0.892	4	0.108	5	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.7	7	0.7	0	0	0	1
9 - Segment 9.	1	0.1	1	0.1	0	0	0	0
10 - Segment 10.	8	0.6	5	0.5	1	0.1	2	0
Totals	**334**	**7**	**245**	**6.723**	**10**	**0.277**	**39**	**40**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Negative	View
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil		
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson		
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid	Saurabh Saksena		
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	PacifiCorp	Ryan Millard	Affirmative	
1	PECO Energy	Ronald Schloendorn		
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 2 of Grant County	Kyle M. Hussey	Affirmative	View
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	

1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	View
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Arkansas Electric Cooperative Corporation	Philip Huff	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Ralph J Schulte	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	CJ Ingersoll	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	

3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	Mississippi Power	Jeff Franklin	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Oregon Trail Electric Cooperative	ned ratterman		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Clallam County	David Proebstel	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	View
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	View
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	

5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	View
5	Edison Mission Energy	Ellen Oswald	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino		
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Abstain	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Mississippi Electric Power Association	Jerry W Johnson	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	

5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	ACES Power Marketing	Jason L Marshall	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Abstain	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	New York Power Authority	William Palazzo	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Negative	View
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	View
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Edward C Stein	Affirmative	
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Network & Security Technologies	Nicholas Lauriat	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Negative	View
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Exhibit E

Roster of the interpretation drafting team for the Interpretation of Requirement R.1.1 of CIP-006-4

Name and Title	Company and Address	Contact Info	Bio
Tim Conway, Co-Chair Director, NERC Compliance and Operations Technology	NIPSCO 1500 165th ST Hammond, IN	(219) 853-4202 – Business tjconway@nisource.com	Mr. Conway is Director of NERC Compliance and Operations Technology at Northern Indiana Public Service Company (NIPSCO). Formerly, he was an EMS Computer Systems Engineer at NIPSCO for eight years, with responsibility over the control system servers and the supporting network infrastructure. He is the former Chair of the RFC CIPC and current Co-Chair of the NERC CIP Interpretation Drafting Team. Mr. Conway holds an MBA from the University of Notre Dame, a BS in Electrical Engineering Technology from Purdue University, and he has the obtained following professional certifications throughout his career: RHCT, SANS GCIH, CNE, Network +, CCNA, CISA, CRISC.
Scott Miller, Co-Chair Manager Corporate Affairs	MEAG Power 1407 Riveredge Parkway NW Atlanta, GA 30328 (678) 644-3524 - Business smiller@meagpower.org	(678) 644-3524 - Business smiller@meagpower.org	Mr. Miller actively works with American Public Power Association (APPA) and the Large Public Power Council (LPPC) Reliability Team to develop multi-company responses and positions on CIP standard developments as well as other NERC standards. He is an active member of the NERC Quality Review Team, and he has completed SOS NERC Training modules for relays, power plant operations, security, and other topics. Responsibilities include working on cyber issues that require the continual studying of cyber network and network security texts, and to monitor and review Congressional, FERC and NERC committee hearings, meetings and webinars. He has more than 30 years of electric and natural gas industry experience, which includes providing research, proposals, and testimony to FERC and the Illinois Commerce Commission as the primary liaison and witness on gas and electric rate making, engineering practices, and accounting/equipment life cycle studies. At MEAG Power, he provides 25 municipal electric distribution utilities with system planning and operational support. Mr. Miller has held various management and executive staff positions, and he is a USAF veteran and holds a BA and an MBA with an emphasis in numerical analysis. He is a member of the NERC CIP Interpretation Drafting Team.

Name and Title	Company and Address	Contact Info	Bio
Mark Engels Enterprise Technology Security & Compliance Director	Dominion 707 East Main Street Richmond, VA 23219	(804) 775-5263 – Business mark.engels@dom.com	Mark Engels is the Enterprise Technology Security and Compliance Director at Dominion and has been with the company 33 years. Mr. Engels is formerly a member of NERC's Cyber Security Standard Education Team (CSSET), which created the compliance audit presentation used at three NERC sponsored 1200 standard workshops and created the compliance audit presentation used at 10 NERC sponsored CIP-002-1 through CIP-009-1 standard workshops. Mr. Engels is currently a member of NERC's Critical Infrastructure Protection Committee (CIPC), chair of the NERC Control System Security Working Group (CSSWG), chair of the NERC Cyber Attack Task Force, and a member of the Southeastern Electric Reliability Corporation (SERC) CIPC leadership committee. He is a member of the NERC CIP Interpretation Drafting Team.
Jeffrey Fuller Senior Manager, Enterprise Security Services			Jeffrey Fuller is responsible for the management of the Enterprise Security department at his company, including cyber security, contract security, security incident response plans, risk assessments, and auditing activities. He has managed the Critical Infrastructure Protection (CIP) Program as well as industry SOX and PCI compliance requirements. Mr. Fuller is an active member of the NERC and RFC CIPC as well as an observer of the NERC Project 2008-06 SDT and other working groups. He brings a background that includes experience in IT, law enforcement, and compliance. He is a member of the NERC CIP Interpretation Drafting Team. Education: BS – Information Technology – WGU School of Police Staff and Command - NWU Certifications: Certified Information Systems Security Professional (CISSP) / Microsoft Certified Systems Engineer (MCSE) / Microsoft Certified Systems Administrator (MCSA) / Cisco Certified Network Associate (CCNA) / Microsoft Certified Desktop Support Technician (MCDST) / Microsoft Certified Trainer (MCT) / CompTIA Security+, Network+ and A+.

Name and Title	Company and Address	Contact Info	Bio
Trevor MacCrae Staff Compliance Analyst	Southern Company Transmission 600 N. 18th St., M/S 7S-8220 Birmingham, AL 35203	205-257-6210 – Business tmaccrae@southernco.com	As the senior EMS compliance analyst for Southern Company, Mr. MacCrae focuses on cybersecurity regulatory compliance for Transmission Energy Management Systems (SCADA) including strategy, process management, performance improvement, and compliance systems implementation. He is the Technical Feasibility Exception (TFE) program lead and a frequent contributor and team member participating in EMS programs related to audits, peer reviews, and industry groups. He has a Bachelor's Degree in Information Technology and an MBA with a concentration in Operations Management. He is a certified information systems security professional (CISSP) and recently passed the certified information security manager (CISM) examination. He serves as a Subject Matter Expert for the Electric Sector Cybersecurity Risk Management Maturity initiative, a U.S. Department of Energy program. He also serves as a member of the Industrial Control Systems Joint Working Group (ICSJWG) and is a member of the Roadmap to Secure Industrial Control Systems Subgroup. The DHS Control Systems Security Program (CSSP) established the Industrial Control Systems Joint Working Group (ICSJWG) to facilitate information sharing to reduce the risk to the nation's industrial control systems. He also serves as a member of the Utility Information Technology Benchmark and Best Practices (UNITE) NERC CIP team, which is a standing utility industry benchmarking team that shares benchmarking and best practices among its utility industry members. He is a member of the NERC CIP Interpretation Drafting Team.
Brian Newell Senior Instrumentation and Controls Engineer	American Electric Power 1 Riverside Plaza, 21st Floor Columbus, OH 43215	(614)716-2106 - Business benewell@aep.com	Brian Newell is a Senior Instrumentation and Controls Engineer with American Electric Power (AEP). Brian joined AEP in 2004. Previously, he was with ABB and Bailey Controls Company in engineering and technical support roles. Brian has over 14 years of experience with Distributed Control System (DCS) and Programmable Logic Controller (PLC) design, engineering, and testing. He has extensive experience in DCS, PLC, protective relay, data recorder, and Remote Terminal Unit (RTU) communications, networking, and security implementation from multiple vendor products. His current responsibilities include serving as a subject matter expert for the cyber security program implementation across the control, monitoring, and protection system equipment for AEP's Fossil and Hydro Generation fleet. He has also been an active observer of the NERC CIP Standards Drafting Team for over 2 years. Brian is a licensed Professional Engineer in Ohio. He is a member of the NERC CIP Interpretation Drafting Team.

Name and Title	Company and Address	Contact Info	Bio
Robert Ulmer CIP Compliance Consultant	American Transmission Company P.O. Box 47 Waukesha, WI 53188	(262) 506-6850 rulmer@atcllc.com	Robert Ulmer is responsible for American Transmission Company's (ATC) NERC Critical Infrastructure Protection (CIP) compliance program and he is a former CIP senior manager. He is also an alternate MRO member on the NERC CIPC. Mr. Ulmer joined ATC in 2001 as director of corporate services where he established ATC's information technology and security functions. In 2008, he was appointed project director for the construction of ATC's system control center and corporate headquarters in Waukesha, Wisconsin. Prior to joining ATC, Mr. Ulmer held a number of positions at We Energies and subsidiaries in nuclear power, finance, human resources, and co-generation projects in Latin America. He is a graduate of Carroll University and the University of Michigan Executive Program. He is a member of the NERC CIP Interpretation Drafting Team.

From:	Guy V. Zito
To:	brian.robinson@utilitysvcs.com; Lee R. Pedowicz; rscmembers; "Joel Charlebois"; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject:	RE: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols
Date:	Friday, May 11, 2012 10:09:40 AM

Brian,

We can discuss this at the next meeting. There is a jurisdictional issue that we have discussed in the past and seems to be continually evolving.

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Brian Robinson [mailto:Brian.Robinson@utilitysvcs.com]
Sent: Friday, May 11, 2012 9:35 AM
To: Guy V. Zito; Lee R. Pedowicz; rscmembers; 'Joel Charlebois'; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: RE: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols

It is my understanding that reliability standards are to only be applicable to BES facilities unless otherwise stated in the applicability section of the standard. If it is the intent to apply this standard to non-BES facilities I think a clarification is necessary.

Brian Robinson
Associate
Utility Services

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From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Friday, May 11, 2012 9:27 AM
To: Brian Robinson; Lee R. Pedowicz; rscmembers; 'Joel Charlebois'; donald.e.nelson@state.ma.us;

rjfalsetti@cogeco.ca
Subject: RE: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols

Brian,

I would agree that the standard will reach down into the DP operations. As Mr. Pedowicz always states, everything can impact the BES. Clarification might be beneficial.

Also there is a fundamental issue that I am seeing with this standard. There are a number of references appearing that state "excluding Reliablity Directives". If Reliability Directives is being defined under a separate project, how will stakeholders understand what is really being excluded for the pusposes of this standard's scope?

Guy V. Zito
Asst. Vice President-Standards
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1040 Avenue of the Americas, 10th Floor
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From: Brian Robinson [mailto:Brian.Robinson@utilitysvcs.com]
Sent: Wednesday, May 09, 2012 3:03 PM
To: Lee R. Pedowicz; rscmembers; 'Joel Charlebois'; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: RE: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols

Good Afternoon,

Comment regarding COM-003:

The applicability of this standard is unclear in the case of Distribution Providers. The definition of Operating Communication includes "Elements" that could impact the BES. The NERC Glossary definition for Elements includes non-BES devices and equipment. Additionally, the Purpose section of the standard states "harmful to the reliability of the BES." Since non-BES Elements could affect the BES this standard could be deemed applicable to non-BES devices. If it is the intent of the SDT to apply this standard to All Operating Communications concerning both BES and non-BES Facilities this should be explicitly stated in the applicability section for transparency. Otherwise clarifying language should be added to exclude non-BES Facilities.

Would you agree?

Thanks,

Brian Robinson
Associate

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From: Lee R. Pedowicz [mailto:lpedowicz@npcc.org]
Sent: Monday, May 07, 2012 11:20 AM
To: rscmembers; 'Joel Charlebois'; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols

Good morning.

Attached is a copy of the Comment Form for Project 2007-02 Operating Personnel Communications Protocols posted for comments, and supporting materials. Please let me know your comments by Friday, June 8, 2012. Comments are due to NERC June 20, 2012.

Thanks.

Lee

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Definition of Adequate Level of Reliability

Industry Webinar
May 23, 2012, 1:00-3:00 p.m. ET

RELIABILITY | ACCOUNTABILITY






Outline

- Background
- Definition and Reliability Objectives
- Supporting Documents
- Industry Feedback
- Next Steps
- Questions and Answers



Background

Background

- Adequate Level of Reliability Task Force (ALRTF) charged with:
  - Reviewing current definition of ALRTF (filed for information with FERC in 2008)
  - Determining if existing definition and characteristics need enhancement in coordination with the Member Representatives Committee's (MRC's) Bulk Electric System (BES)/ALR Policy Group
- Task Force includes representatives from each of the Standing Committees : Standards Committee, Compliance and Certification Committee, Operating Committee, Planning Committee, Critical Infrastructure Protection Committee
- Has met regularly since June 2011

Background

- Goal:
  - Develop definition that encompasses NERC's responsibility to ensure reliability
  - Define objectives and characteristics that are measurable*
  - Enable the ERO enterprise to focus on and align its activities with specific characteristics of ALR that have the greatest impact on BES reliability
- Definition must be:
  - Concise, yet self-contained
  - Self-explanatory to BES planners and operators
  - Meaningful to policymakers; placing a premium on translation in the ALRTF Report

*Qualitative only; quantitative measures to be developed via standards.

Background

- Input from MRC's BES/ALR Policy Group directed group to consider:
  - Cost/benefit
  - Load loss distinctions
  - Definition of Cascading

Draft Definition: Overview

- Seven Reliability Objectives
- Associated Expected Performance Outcomes
  - Expressed in four time frames:
    - Steady State
    - Transient
    - Operator response
    - Recovery and system restoration
- Associated Disturbances
  - Both predefined and beyond the scope of predefined Disturbances



Definition and Reliability Objectives

Draft Definition: Preambles

- Reliability objectives are “what’s” not “how’s”
  - Not bound by jurisdictional implications
- Reliability objectives support standards development
  - But not every reliability objective requires or will result in a standard
- Each objective has some expected performance outcomes under specific events
  - i.e., when subject to predefined Disturbances
- Expected performance outcomes are presented qualitatively at a high level, in different time frames
- Predefined Disturbances are “categorized,” not details

Draft Definition: Time Frames

- Time frames for expected performance outcomes:
  - Steady State – pre-disturbance
  - Transient – during the disturbance, from milliseconds to seconds, with automatic responses and control actions
  - Operator response – from seconds to minutes/hours, with some automatic actions plus operator actions
  - Recovery and system restoration – post disturbance, from minutes to hours, with actions to re-establish a sustainable operating state and then a new steady state that meets specific reliability objectives established by the circumstances of the Disturbance

Predefined Disturbances

- Predefined Disturbances – the events under which the performance outcomes are expected
- Predefined Disturbances set the scope of expected performance outcome for Reliability Objectives 1 to 5
  - Not applicable to Objectives 6 and 7 as these two address post-Disturbance situations
- Predefined Disturbances are deterministic, but are deemed to have a reasonable probability of occurring
  - To scope the design, planning and operation of BES
    - e.g., loss of single transmission circuit due to lightning strike

Predefined Disturbances

- Predefined Disturbances – specific events or grid Disturbances in 3 categories:
  - Steady state, no contingencies: everything more or less as expected/forecast
  - Events resulting in loss of BES element(s) in a single protection zone
    - e.g., due to equipment failure, lightning strike on a transmission tower tripping a single circuit
  - Events resulting in loss of two or more BES elements not in a common protection zone
    - e.g., due to protection or breaker failure to clear initial faults; lightning strike on a transmission tower tripping two circuits

Predefined Disturbances

- Beyond Predefined Disturbances – specific events or Disturbances in two categories:
  - Extreme Events: Two or more dependent or separate events occurring simultaneously, or in close time proximity, resulting in the removal of two or more BES elements not common to a single zone of protection
    - e.g., tornadoes removing circuits on the same right of way; common cause resulting in the loss of a substation or a generating plant
  - High-Impact, Low-Frequency (HILF) Events: A class of improbable events with the potential to significantly affect the reliability of the BES
    - e.g., Geomagnetic Disturbances (GMD); coordinated cyber and/or physical attacks

Reliability Objective #1

- The BES is free from instability, uncontrolled separation, Cascading, and voltage collapse under normal operating conditions and when subject to predefine Disturbances.
- Expected performance outcomes:
  - Stable frequency and voltage within predefined range
  - Adequate reactive reserve maintained
  - No Cascading
- Applicable Time Frames (1, 2, 3):
  - (1) Steady State
  - (2) Transient
  - (3) Operator Response

Reliability Objective #2

- BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined Disturbances.
- Expected performance outcomes:
  - Stable frequency within predefined range
  - BES equipment frequency limits satisfied
  - Frequency oscillations experience positive damping
- Applicable Time Frames (1, 2, 3):
  - (1) Steady State
  - (2) Transient
  - (3) Operator Response

Reliability Objective #3

- BES voltage is maintained within defined parameters during normal operating conditions and when subject to predefined Disturbances.
- Expected performance outcomes:
  - Stable voltage within predefined range
  - BES equipment voltage limits satisfied
  - Voltage oscillations experience positive damping
- Applicable Time Frames (1, 2, 3):
  - (1) Steady State
  - (2) Transient
  - (3) Operator Response

Reliability Objective #4

- Sufficient transfer capability of the BES transmission system is provided and maintained to meet required BES demands during normal operating conditions and when subject to predefined Disturbances.
- Expected performance outcome:
  - Deliver sufficient resources to meet load obligations using the BES while operating within established operating parameters (e.g. thermal, voltage, equipment ratings)
- Applicable Time Frames (1, 2, 3):
  - (1) Steady State
  - (2) Transient
  - (3) Operator Response

Reliability Objective #5

- Sufficient resource capability on the BES is provided and maintained to meet required BES demands during normal operating conditions and when subject to predefined Disturbances.
- Expected performance outcome:
  - Have sufficient resources to meet load obligations within established operating parameters (e.g., ancillary services).
- Applicable Time Frames (1, 2, 3):
  - (1) Steady State
  - (2) Transient
  - (3) Operator Response

Reliability Objective #6

- Adverse Reliability Impacts on the BES resulting from conditions beyond the scope of predefined Disturbances (e.g., multiple contingences, unplanned and uncontrolled outages, cyber security events, malicious acts) are minimized.
- Expected performance outcomes:
  - Propagation of cascading or collapse limited
  - The BES is returned to a stable state with resources and load restored efficiently
- Applicable Time Frames (2, 3, 4):
  - (2) Transient
  - (3) Operator Response
  - (4) Recovery and System Restoration

Reliability Objective #7

- The system has the ability to recover from major system Disturbances, such as blackouts and widespread outages, by restoring BES Facilities in a controlled manner that rebuilds BES integrity and restores supply to load.
- Expected performance outcome:
  - Recover the BES and restore available resources and load to a stable interconnected operating state expeditiously after a major system Disturbance
- Applicable Time Frames (4):
  - (4) Recovery and System Restoration

Examples of Expected Performance Outcome

- BES is stable and exhibits positive damping after a predefined Disturbance
- Steady state frequency at 60 Hz +/- a margin
- Disturbance Control Standard (DCS):
  - Recovery in 15 minutes
- Steady state voltage at nominal value +/- a margin
- Sufficient transmission transfer capability to deliver resource to meet system demand under peak load condition
- Loss of load probability at x day/y years



Supporting Documents

Technical Document

Technical Report Supporting Definition of Adequate Level of Reliability"

- Introduction
- Overview of ALR Definition Structure
- Performance Outcomes
- Causes of Disturbances
- Comparison with current ALR definition with the proposed ALR definition
- Appendix: Means to Meet Reliability Objectives (with examples for illustration)

Other Associated Work

- *Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles*
- *Discussion Paper: Risk Tolerance for Widespread Bulk Electric System Outages with Significant Socio-Economic Impacts of Reliable BES Operations*



Discussion Paper: Risk Tolerance for Widespread BES Outages with Significant Socioeconomic Impact

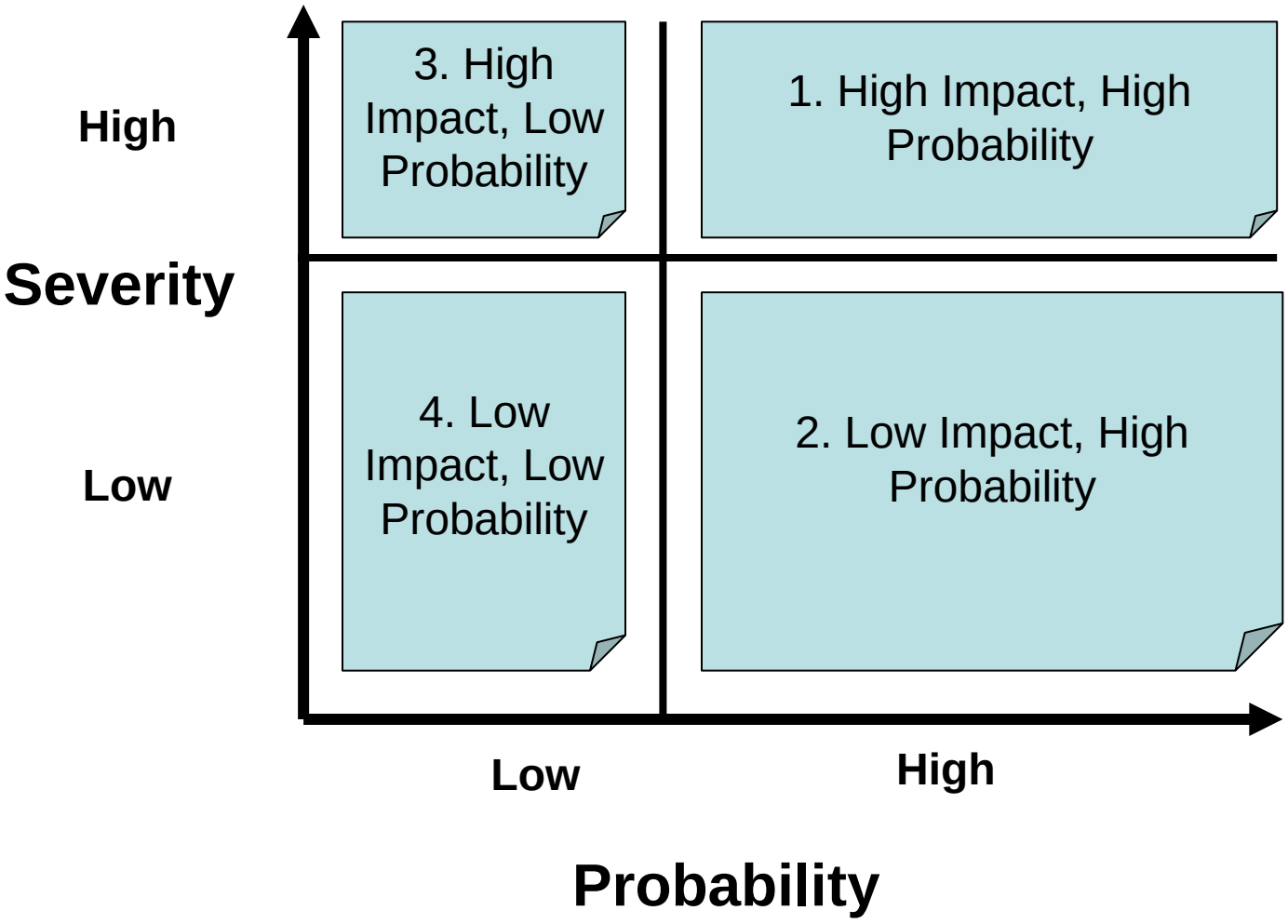
Optimizing Risk Mitigation to the Risk

- What is the “right” balance of costs of risk prevention vs. the cost of the risk itself?
  - Society cannot afford the cost of a power system immune to blackouts
  - Society cannot afford too many blackouts
- We know how to measure costs, but, how do we measure risk?
  - Probabilistic Risk Management framework
- We do not currently have the data necessary to perform this risk analysis, but, we are already working towards it…

Defining a Risk Tolerance

- What are the magnitudes of risk and probability of risk that society can and cannot tolerate?
- Magnitude
  - Society has a fairly high tolerance for localized distribution outages
  - Society has a low tolerance for widespread blackouts
  - What magnitude of risk/blackout is worth managing from a continental, socioeconomic perspective? (e.g., how much water makes a flood?)
- Frequency
  - It cannot be never
  - It cannot be once a year
  - Is there a metric similar to the 30 year flood plain that we can develop?
- Risk Tolerance = fulcrum point balancing of social cost of mitigation vs. social cost of the outage risks

Managing Risk

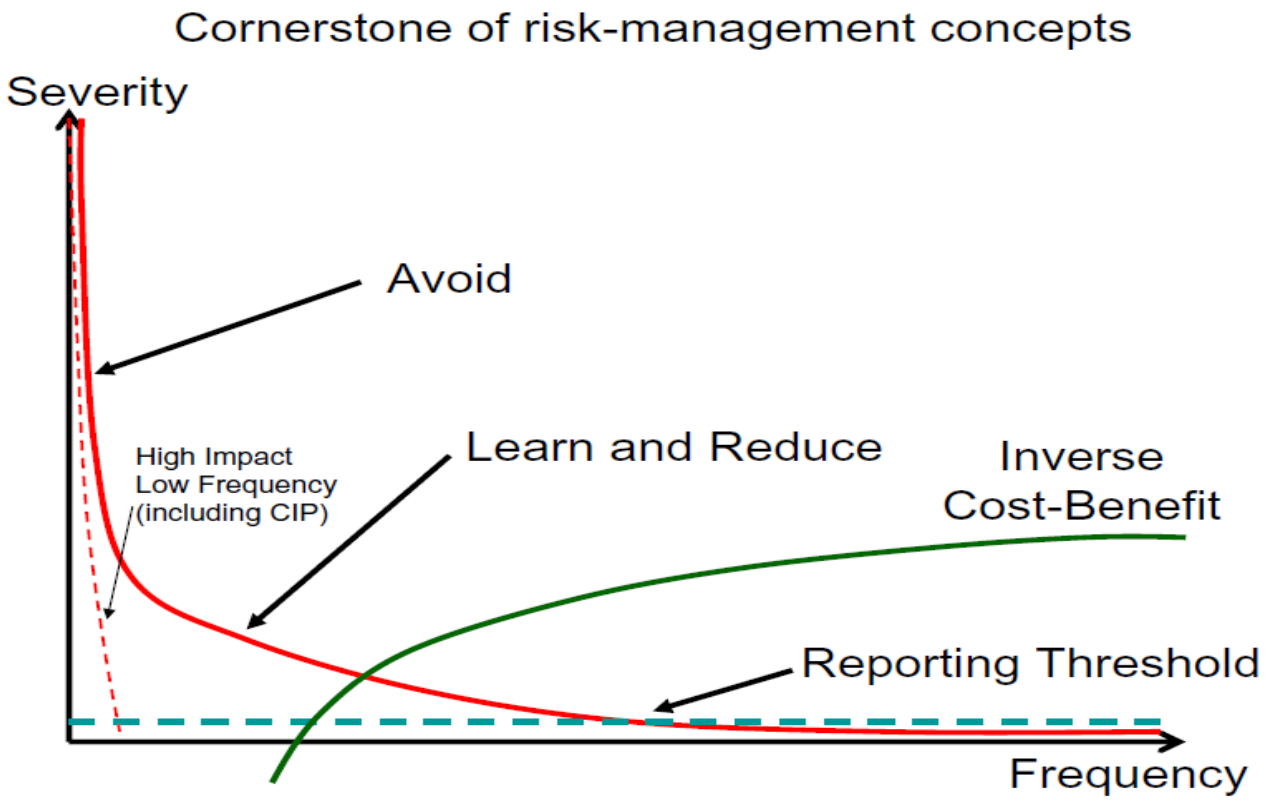


Managing Risk

- Quadrant 1: High Impact, High Probability
  - Plan, design and operate to prevent risks from residing in this quadrant
- Quadrant 2: Low Impact, High Probability
  - Establish deterministic criteria, e.g., operate within limits for a single contingency
- Quadrant 3: High Impact, Low Probability
  - Two strategies:
    - Emergency preparedness and response to reduce both impact and probability of an event (acts of nature, extreme “bad luck”)
    - Defense in depth (acts of aggression)
- Quadrant 4: Low Impact, Low Probability
  - Learning opportunities

NERC is Already Using These Concepts

Reliability Risk Management Concepts



Should We Head in This Direction?

- Migrate from ALR criteria largely deterministic in nature to criteria more probabilistic in nature?
- Develop stochastic analytical methods to define ALR based on many variables and a balance of cost of risk mitigation vs. the cost of the risk itself?
  - Similar to Loss of Load Probability (LOLP)/Loss of Load Expectation (LOLE) analyses that are used to determine resource adequacy at the State/Province level
- If so, what are the recommended next steps?



Industry Feedback: What We Need From You

Question 1

- ALRTF chose to develop the ALR definition by presenting the performance state that the design, planning, and operation of the BES will achieve by meeting a set of reliability objectives
  - *Do you agree with this approach?*

Question 2

- Reliability Objectives #1, #2, and #3 are aimed at maintaining BES integrity and normal operating state (voltage and frequency ranges)
  - *Do you agree with these reliability objectives and their associated performance outcomes?*

Question 3a

- Reliability Objectives #4 and #5 are aimed at maintaining adequate BES capabilities (resource and transmission) to meet required BES demands.
  - *Do you agree with these reliability objectives and their associated performance outcomes?*

Question 3b

The ALRTF concluded that:

- Meeting required BES demands is the fundamental reason for ensuring BES integrity and maintaining normal operating states (voltage and frequency).
- Adequate resource and transmission capabilities need to be provided to meet forecast demands.
- EPA 215 does not provide FERC and NERC the authority to require or enforce provision of these capabilities,

- The ALRTF proposes these reliability objectives only to aid assessment of future needs but does not prescribe how or by whom the required BES capabilities will be provided.
  - *Do you agree that this is an acceptable approach?*

Question 3c

- In Reliability Objectives #4 and #5, the ALRTF uses the phrases “required BES demands” and “meet load obligations” to refer to transmission and resource adequacy.
  - *Do you believe this language is clear?*

Question 4

- Reliability Objectives #6 and #7 are aimed at responding to BES events that go beyond those covered in Reliability Objectives #1-5 (beyond the predefined Disturbances)
  - *Do you support these objectives?*

Question 5

- Performance Outcomes and Disturbances
  - Technical Report provides additional detail, but at a high level
  - Specific performance outcomes and Disturbances will be developed in the standards development process
    - *Do you support this approach?*

Question 6

- Time Frames
  - The Technical Document presents four time frames for performance outcomes.
    - *Does this help fully describe each performance outcome?*

Question 7

- *Does the ALRTF's proposed definition of ALR improve upon the current definition?*
  - Current definition was filed with FERC for information in 2008

Current definition of ALR: http://www.nerc.com/files/Adequate_Level_of_Reliability.pdf

Question 8

- NERC's 8 Reliability Principles and ALR:
  - Reliability Principles are approved by NERC's Board and are incorporated into the Standards Processes Manual
  - As of now, new standard requirements must be tied to one of the principles
    - *Are both the Reliability Principles and ALR Definition necessary?*

Reliability Principles: http://www.nerc.com/files/Reliability_Principles.pdf

Question 9

- BES v. Bulk-Power System (BPS) v. System
  - BES: NERC Glossary Term
  - BPS: Specific statutory definition applicable within the U.S.
  - System: Used in the current Board-approved definition of ALR, but is very broad
- *ALRTF chose to use BES; do you support this approach?*

Question 10

- *Other comments or feedback?*



Next Steps

Schedule

- **April 23 - June 23, 2012:** Public comment period
- **May 23, 2012:** Webinar
- **June 28, 2012:** ALRTF Meeting
- **July - August, 2012**: Revise Draft ALR Definition and Technical Document based on comments; prepare and submit package for Board of Trustees endorsement/consideration; consider next steps on Socio-Economic Impact Discussion Paper.

Questions?

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Attachment to April 2, 2012 Definitions Memorandum

List of terms with discrepancies in the Rules of Procedure and Glossary of Terms Used in Reliability Standards

Term	ROP Appendix 2	Glossary
Cyber Assets –	programmable network devices and communications networks including hardware, software, and data.	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Security Incident –	any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Interconnection –	a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the facilities within their control.	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection Reliability Operating Limit –	the value (such as MW, MVar, amperes, frequency or volts)	A System Operating Limit that, if violated, could lead to instability,

Term	ROP Appendix 2	Glossary
	derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s), or cascading outages.	uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.
Net Energy for Load –	net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Planning Authority –	the responsible entity that coordinates and integrates transmission facilities and service plans, resource plans, and Protection Systems.	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Point of Delivery –	a location that a Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a load-serving entity receives its energy.	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt –	a location that a Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a load-serving entity receives	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its

Term	ROP Appendix 2	Glossary
	its energy.	output.
Protection System –	protective relays, associated communications systems, voltage and current sensing devices, station batteries and DC control circuitry.	Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.
Reliability Coordinator Area –	the collection of generation, transmission and loads within the boundaries of the Reliability Coordinator.	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reserve Sharing Group –	a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling

Term	ROP Appendix 2	Glossary
	energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g. ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.	energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Sink Balancing Authority –	the Balancing Authority in which the load (sink) is located for an Interchange Transaction.	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority –	the Balancing Authority in which the generation (source) is located for an Interchange Transaction.	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)
Special Protection System –	an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of

Term	ROP Appendix 2	Glossary
	faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. A Special Protection System does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a Special Protection System).	faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
System Operating Limit –	the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings

Term	ROP Appendix 2	Glossary
		(Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
Transmission Customer –	(1) any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can and does receive Transmission Service. (2) Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

MEMORANDUM

TO: Reliability Standards Team

FROM: NERC Legal Department

DATE: April 2, 2012

SUBJECT: Discrepancies in Definitions between the NERC Rules of Procedure and the Glossary of Terms Used in Reliability Standards

Questions have been raised over which source of a definition should be controlling when determining the meaning of a NERC defined term because there are two such sources of authority – (1) the Glossary of Terms Used in NERC Reliability Standards ("Glossary of Terms"), [1] and (2) Appendix 2, Definitions Used in the Rules of Procedure ("ROP").[2] Currently, there are some terms that are defined in both places, and the definitions vary from one another. This memorandum addresses the issue of discrepancies that exist in the definitions of terms used in the ROP and those used in the Glossary of Terms and clarifies which definition should be controlling. Attached is a compilation of all the discrepancies we are aware of.

The Glossary of Terms is to be used as the authoritative source for the definitions of terms used in Reliability Standards while the ROP Appendix 2 – Definitions Used in the Rules of Procedure - is to be used as the authoritative source for the definitions of terms used in the ROP. Going forward, (1) NERC should seek to minimize or eliminate different definitions for the same term, and (2) NERC documents referencing defined terms should identify which definition source the reader should use to obtain the correct meaning of a defined term.

DISCUSSION

On January 31, 2012, the Federal Energy Regulatory Commission ("FERC") issued an *Order Approving Amendments to Rules of Procedure*[3] which implicitly addresses this issue by acknowledging that differing terms exist in the ROP and the Glossary of Terms and that the terms are sufficiently separated in their applications. The *Order Approving Amendments to Rules of Procedure* addressed a concern raised by the City of Santa Clara, California ("Santa Clara").

Santa Clara asserted that NERC should: (1) include a footnote in the ROP explaining that the definitions used in the ROP are for use only in the ROP; and (2) clearly identify terms in the ROP differing from terms in the Glossary of Terms. FERC stated (at P 11):

> In regard to Santa Clara's comments, the Commission does not believe that the requested revisions are necessary because Appendix 2 to the ROP [*Definitions Used in the Rules of Procedure*] includes a sentence explaining that the definitions set forth apply only to the

[1] Glossary of Terms Used in NERC Reliability Standards. Available at: http://www.nerc.com/files/Glossary_of_Terms.pdf.
[2] Rules of Procedure ("ROP"), Appendix 2
[3] *Order Approving Amendments to Rules of Procedure*, 138 FERC ¶ 61,072 (2012).

> Rules of Procedure. Further, NERC identifies terms in the Rules of Procedure as derived from the *Glossary of Terms* with double asterisks. Thus, we believe the notations as proposed in Appendix 2 adequately identify that the terms therein are for use in the Rules of Procedure only, without the need for additional context. The approach taken by NERC sufficiently maintains consistency in the use of defined terms throughout the Rules of Procedure while preventing changes in the *Glossary of Terms* from automatically altering the definitions used in the Rules of Procedure outside of the revision process.

The NERC ROP section 302, *Essential Attributes for Technically Excellent Reliability Standards,* and the *Standard Processes Manual*, Appendix 3A to the ROP, make clear that the Glossary of Terms is to be used for identified terms that are used in the reliability standards.

Section 302 of the ROP states that one of the essential attributes is consistent terminology and that "[t]o the extent possible, reliability standards shall use a set of standard terms and definitions that are approved through the NERC reliability standards development process."[4]

The *Standard Processes Manual* includes a section that outlines the "Process for Developing a Defined Term" which states:[5]

> NERC maintains a glossary of approved terms, entitled the "*Glossary of Terms Used in Reliability Standards*." The glossary includes terms that have been through the formal approval process and are used in one or more NERC Reliability Standards. Definitions shall not contain statements of performance requirements. … The Glossary of Terms is intended to provide consistency throughout the Reliability Standards. [6] (Internal citations omitted).

The Glossary of Terms also provides guidance on this issue. The Glossary of Terms is prefaced with the statement that "[t]his Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees …."[7]

CONCLUSION

The Glossary of Terms is to be used as the authoritative source for the definitions of terms used in Reliability Standards, while the ROP Appendix 2 – Definitions Used in the Rules of Procedure - is to be used as the authoritative source for the definitions of terms used in the ROP. Generally, NERC should try to avoid defining the same term differently in the Glossary of Terms and the ROP but this practice is not expressly prohibited. For other NERC documents referencing defined terms, the author should identify which definition source the reader should use to obtain the correct meaning of a defined term.

[4] NERC Rules of Procedure section 302.10 *Essential Attributes of Technically Excellent Reliability Standards*.
[5] *Standard Processes Manual*, Appendix 3A to the ROP at pp 22-23.
[6] *Id* at p. 22.
[7] Glossary of Terms, *Introduction*.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

PROJECT 2010-17 DEFINITION OF BES (PHASE 2)

Meeting Notes

Tuesday, May 1, 2012 | 8:30 a.m. – 5:00 p.m. EDT
Wednesday, May 2, 2012 | 8:30 a.m. – 5:00 p.m. EDT
NERC 3353 Peachtree Road NE Suite 600, North Tower Atlanta, GA 30326
Local contact: Wendy Kinnard 1.404.446.9735

Administrative

1. **Introduction**
   The Chair called the meeting to order at 8:30 a.m. on Tuesday, May 1, 2012 in the NERC offices in Atlanta, GA. Meeting participants were:

Members		
Jennifer Dering, NYPA	Brian Evans-Mongeon, Utility Services	Ajay Garg, Hydro One
Pete Heidrich, FRCC, Chair	John Hughes, ELCON	Barry Lawson, NRECA, Vice Chair
Jeff Mitchell, RFC	Rich Salgo, Sierra	Jason Snodgrass, GTC
Jennifer Sterling, Exelon	Jonathan Sykes, PG&E	Ed Dobrowolski, NERC, Coordinator
Observers		
Richard Dearman, TVA	David Dockery, AECI	Tom Duffy Central Hudson
Jeff Gindling, Duke	Mike Green, EES	Bill Harm, PJM
Bill Hughes, Redding	Lorissa Jones, BPA	Ruth Kloecker, ITC
Susan Morris, FERC	Alain Pageau, HQ	DeWayne Scott, TVA
Tim Soles, Occidental	Phil Tatro, NERC	Henry Tsay, NPCC

2. **Determination of Quorum**
   The rule for NERC Standard Drafting Teams (SDT) states that a quorum requires two-thirds of the voting members of the SDT to be physically present. Quorum was achieved.

3. **NERC Antitrust Compliance Guidelines and Public Announcement**
   The NERC Antitrust Compliance Guidelines and public announcement warning were issued.

4. **Membership Changes and Roster Updates**
   There were no changes to the members information.

5. **Review Meeting Agenda and Objectives**
   No changes were made to the agenda. The main objective of the meeting was to review the guidance document.

Agenda

1. **Updates on Phase 2 – Pete Heidrich**

   a. Operating and Planning Committees

      The Operating Committee is not going to be deeply involved. The Planning Committee is taking the lead in the activities and the Operating Committee will follow the developments through a liason with the Planning Committee's Executive Committee (PC Ex Com).

      The PC Ex Com will handle the bright-line voltage criteria study. Pete Heidrich, Barry Lawson, and Ed Dobrowolski have been added to the mail list for this group and will monitor the activities. Jeff Mitchell is Chair of the Planning Committee and thus Chair of the PC Ex Com as well.

      The Reliability Assessment Subcommittee (RAS) will deal with the generation threshold study. Phil Fedora is a member of this group and will liaise for the SDT.

      The Systems Analysis and Modeling Subcommittee (SAMS) will work on the reactive power threshold and the local network power flow issue. Bill Harm is a member of this group and will act as liaison for the SDT.

      The liaisons will provide periodic reports at SDT meetings.

      The Planning Committee has an absolute deadline of no later than December 20, 2012 for providing the results of its work.

      Subcommittee meetings are open so SDT members could dial-in if so desired. Bill Harm and Phil Fedora will send out meeting notices to the SDT to facilitate this effort.

      AI – Bill Harm will send SAMS meeting notice information to the SDT and Phil Fedora will provide RAS meeting information to the SDT.

      The PC Ex Com is a closed session as other matters are also discussed.

   b. Standards Committee

i. SAR status

The Standards Committee approved the project schedule, accepted the revised SAR, and approved the project for development at its April meeting.

c. MRC/BOT

The MRC and BOT both meet next week. Pete Heidrich is on the agenda and will provide a project update. He will provide a copy of the presentation to the SDT.

AI – Pete Heidrich will distribute a copy of the MRC/BOT presentation to the SDT members.

A question was raised on the City of Holland order. Pete Heidrich pointed out that the ruling was based on the present BES definition and not the revision from the SDT Phase 1 work. It would therefore be premature to discuss the ruling with regard to its effect on the revised definition.

2. **Review of Guidance Document**

Pete Heidrich provided a draft guidance document that built on the efforts of the individual sub-teams in previous meetings. The SDT reviewed the document and made the following recommendations and changes:

- Introduction
  - A question was raised as to whether NERC Legal had reviewed the disclaimer. Ed Dobrowolski stated that the disclaimer was copied from other NERC documents but that it will be sent to NERC Legal for review.

    AI – Ed Dobrowolski to send a copy of the introduction to NERC Legal for their review.

  - Pete Heidrich informed the SDT that the guidance document will not be posted until after FERC responds to the Phase 1 filing. Posting the document prior to that time may result in confusion and wasted effort.
  - The SDT provided some minor grammatical changes to the displayed document.
- Inclusion I1 (Jeff Mitchell and Ken Shortt)
  - Page 4 – grammatical changes to the text box
  - All references to BES and non-BES should be bold throughout the document
  - Need figure identifiers on every figure throughout the document
  - Don't use gray text, use black instead
  - Line 1 isn't always identified in diagrams
  - Page 7
    - This figure is too complicated for this section and should be deleted. It is more pertinent to Exclusion E3.
    - The 2 transformers on the top of the page are not excluded

        - The low side of the transformers need to show greater than or equal to 100 kV
        - There should be a BES box around the reactive resource
- Inclusion I2 (Jennifer Dering, Bill Harm, and Ajay Garg)
    - Page 9
        - Reference should be to Inclusion I2 and not Inclusion I1
        - Add inclusion of transformer under Inclusion I1 in text box
        - Delete the breaker above the unit throught the document
        - Combine pages 9 and 10 with one half showing BES and the other non-BES
        - When moving page 10, delete the BES/non-BES line
        - When moving page 10, use the same langauga as page 9 in the text box
    - Page 11
        - Copy the language in the text box for page 9 in the text box here
        - Place language in the beginning of the diagram section stating that the particular diagrams are only referring to the particular inclusions or exclusions being discussed, e.g., items in the Inclusion I1 diagrams are only pointing out examples for Inclusion I1 and not for any other inclusion or exclusion
    - Page 13 – Place red box around BES unit
- Inclusion I4 (Phil Fedora, Brian Evans-Mongeon, and Russ Noble)
    - Introduction seems overly complicated and was considerably reduced
    - Page 17
        - Need to identify that the common point of connection is the high side of the transformer that connects to the BES
        - Delete the breaker on the low side of the transformer
        - Delete turbine blades from diagrams
    - Page 18 – Non-BES designation is missing on the last transformer to the right
    - Page 19
        - Delete the PCS Shelter reference
        - Delete the inverter boxes and use non-BES boxes as the photovoltaic generators
        - Delete the first breaker in the line
- Inclusion I5 (Jason Snodgrass and Jeff Gindling)
    - Page 21 – on device 1, extend the non-BES box to the left to include the transformer bushings
    - Page 23 – this diagram belongs under Exclusion E3
- Exclusion E1 (Jonathan Sykes, Barry Lawson, Alain Pageau, and Jonathan Hayes)
    - Introduction – several grammatical edits were made by the SDT

- Page 28 – more examples are needed to show the different generation levels similar to Inclusion I2 diagrams while also showing whether the radial exclusion applies or not
- Page 29
  - A non-retail example is required
  - The load transformer voltages are reversed
- Page 31 – grammatical changes were made to the radial exclusion text box

- Exclusion E2 (John Hughes and Tim Soles)
  - Introduction – delete last paragraph but add net capacity (How to handle net capacity should be researched with the various regions – assignments were made as follows for report back at the next meeting: RFC – Jeff Mitchell, FRCC – Pete Heidrich, NPCC – Phil Fedora and Henry Tsay, TRE – Time Soles, MRO & SPP – Ruth Kloecker, SERC – Jason Snodgrass)

    AI – Assigned team members and attendees (RFC – Jeff Mitchell, FRCC – Pete Heidrich, NPCC – Phil Fedora and Henry Tsay, TRE – Time Soles, MRO & SPP – Ruth Kloecker, SERC – Jason Snodgrass) are to research how the regions presently handle net capacity and will report back to the SDT at the next meeting.

  - Page 34 – place a directional arrow on the steam line
  - Page 35 – change kV to MVA in the text box
- Exclusion E3 (Rich Salgo, Ken Shortt, Bill Hughes, and Richard Dearman)
  - Page 38 – carry forward changes discussed under Inclusions I1 and I5
- Exclusion E4 – not completed as yet due to time constraints

3. **Definition Clarification Items**

   a. Non-retail generation (SAR)

   The section on Exclusion E1 in the guidance document contains clarification on this item. The guidance document will be posted for industry comment after FERC responds to the Phase 1 filing and it is expected that any changes to what is currently provided will be driven by those comments. Therefore, no further action on this item is anticipated at this time.

   b. Inclusion I4 Clarlfication (SAR) and Dispersed Generation vs. Distributed Resources (SDT)

   Is wind being treated differently than other resources in Inclusion I2, e.g., why aren't generator leads included in Inclusion I4 as they are in Inclusion I2? This was done intentionally due to the voltage levels that are in play with wind resources. The question was raised as to whether this needs to be re-considered. The sticky point is how you consider dedicated collectors. You could consider them 'lumped' and analaguous to Inclusion I2. The SDT debated the point at length and made tentative wording changes to

both Inclusions I2 and I4 to reflect these changes. The collector systems and everything leading up to them would be included in the BES by this language. This change makes Inclusion I2 consistent with Inclusion I4. There may be unintended consequences to this decision. Each SDT member was asked to study the proposed changes for correctness and to think about unintended consequences of these changes in preparation for detailed discussion at the next meeting.

AI - Each SDT member was asked to study the proposed changes to Inclusions I2 and I4 for correctness and to think about unintended consequences of these changes in preparation for detailed discussion at the next meeting.

c. Flowgates in Exclusion E3 (AECI)

d. Ownership in Exclusion E4 (AECI)

e. Dedicated step-up transformer in Inclusion I2 (PEPCO)

f. Normally open designation in Exclusion E1 (WECC)

g. Gross or net ratings (ACES)

h. Retail Load, Retail Generation, and Retail Meter (ISONE)

i. Reactive resources in Exclusions E1 and E3

j. The relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693

k. The appropriate 'points of demarcation' between Transmission, Generation, and Distribution

4. **Phase 2 Schedule**

In order to maintain an approximately 18 month schedule, some slight variations from a traditional schedule were requested. The schedule was built on the concept that only minor clarifying changes would be made to wording and the significant changes, depending on the Planning Committee findings, would be in threshold values.

A set timeline is shown for the guidance document. However, it will not be posted until after FERC responds to the Phase 1 filing.

5. **Next Steps**

The SDT will continue to work on refining the guidance document and the clarification items. The goal is to have the guidance document ready and waiting when the FERC response is delivered so that it can be published for comment as soon as possible after that if changes aren't required by the response. The clarification items must be finalized by the time the SDT hears back for the Planning Committee on their technical analysis and justification work so that there is no delay in the schedule and that all changes are posted together.

6. **Future Meetings**

   The next meeting of the SDT will be in Chicago, IL at Exelon headquarters on June 27 and 28, 2012. Details will follow.

7. **Action Item Review**

   The following action items were developed during the meeting:

   - Bill Harm will send SAMS meeting notice information to the SDT and Phil Fedora will provide RAS meeting information to the SDT.
   - Pete Heidrich will distribute a copy of the MRC/BOT presentation to the SDT members.
   - Ed Dobrowolski to send a copy of the introduction to NERC Legal for their review.
   - Assigned team members and attendees (RFC – Jeff Mitchell, FRCC – Pete Heidrich, NPCC – Phil Fedora and Henry Tsay, TRE – Time Soles, MRO & SPP – Ruth Kloecker, SERC – Jason Snodgrass) are to research how the regions presently handle net capacity and will report back to the SDT at the next meeting.
   - Each SDT member was asked to study the proposed changes to Inclusions I2 and I4 for correctness and to think about unintended consequences of these changes in preparation for detailed discussion at the next meeting.

8. **Adjourn**

   The Chair thanked NERC for their hospitality and adjourned the meeting at 4:00 p.m. on Wednesday, May 2, 2012.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

PROJECT 2010-17 DEFINITION OF BES (PHASE 2)

Meeting Notes

Project 2010-17 Definition of BES (Phase 2)

Administrative

1. **Introduction**
   The Chair called the meeting to order at 8:00 a.m. CDT on Wednesday, June 27, 2012, in the offices of Exelon in Chicago, IL. Meeting participants were:

Members		
Jennifer Dering, NYPA	Brian Evans-Mongeon, Utility Services	Phil Fedora, NPCC
Ajay Garg, Hydro One	Pete Heidrich, FRCC, Chair	John Hughes, ELCON
Barry Lawson, Vice Chair	Jeff Mitchell, RFC	Rich Salgo, Sierra Pacific
Jason Snodgrass, GTC	Ed Dobrowolski, NERC Coordinator	
Observers		
Bob Cummings, NERC	David Dockery, AECI	Tom Duffy, CHGE
Jeff Gindling, Duke	Chris de Graffenried, Con Ed	Bill Harm, PJM
Jonathan Hayes, SWPP	Bill Hughes, Redding	John Martinsen, Snohomish
Susan Morris, FERC	Alain Pageau, HQ	DeWayne Scott, TVA
Ken Shortt, Pacificorp	Tim Soles, Occidental	Bob Stroh, FERC

2. **Determination of Quorum**
   The rule for NERC Standard Drafting Teams (SDT) states that a quorum requires two-thirds of the voting members of the SDT to be physically present. Quorum was achieved.
3. **NERC Antitrust Compliance Guidelines and Public Announcement**
   It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that

unreasonably restrains competition. It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. The notice included the number for dial-in participation. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

4. **Membership Changes and Roster Updates**

   There were no changes to the roster.

5. **Review Meeting Agenda and Objectives**

   The agenda was approved as drafted.

   The objective of the meeting was to provide updates on liaison work efforts, discuss next steps, and perform a final in-person review of the guidance document.

Agenda

1. **Liaison Reports**

   a. Standards Committee – Pete Heidrich

      The Standards Committee has not met since the last SDT meeting.

   b. MRC/BOT – Pete Heidrich

      The Member Representatives Committee and Board of Trustees will meet in August. There should be an agenda slot for this project with the emphasis expected to be progress on the technical justification work efforts.

   c. PC Ex Com – Jeff Mitchell

      The Planning Committee Executive Committee is looking at the 100 kV bright-line issue as well as overseeing the work done by SAMS and RAS.

      Several alternatives to the 100 kV bright-line such as surge impedance loading (SIL), distribution factors, and MVA capability have been explored but this work is still underway.

      The final report will show the technical rationale for all recommendations and the work is on schedule at this time.

   d. SAMS – Bill Harm

      The Systems Analysis and Modeling Subcommittee (SAMS) is investigating the local network power flow issue and the Reactive Resource threshold value question. Bill Harm distributed a Power Point presentation prior to the meeting that was the basis for the discussion.

All suggested changes have been made from a planning perspective. A 300 MW cap for load within the local network is being suggested and the power flow issue is based on normal and N-1 Contingency flows at peak.

The SDT questioned whether SAMS had received the correct assignment as several of the suggestions appear out of scope. The perspective was questioned as well since the BES definition deals with Real-time issues and is a bright-line with no study requirements. The suggestions made conflict with the local network comments provided by the SDT in Phase 1 of the project. The SDT stated that if SAMS wishes to make out of scope comments about an aspect of the proposed definition that they must do this through the official posting and comment process. The work now must be constrained by the scope of the SAR and the specific request made by the BES SDT and Standards Committee (SC) or it violates standards process.

It appears that the continent-wide studies anticipated by the SDT and SC to provide technical rationales are not within the capabilities of the PC, SAMS, or RAS. Justification for responses will need to be provided by other methods.

The SDT requested a conference call be set up among the SDT leadership and the appropriate PC representatives to make certain that the assignments are understood and that all are on the same page. Jeff Mitchell will provide the contact information for the PC representatives and Ed Dobrowolski will coordinate the call.

AI – Jeff Mitchell will provide the contact information for PC representatives for the conference call concerning the scope of the assignment to the PC.

AI – Ed Dobrowolski will coordinate and set up a conference call between SC leadership and appropriate PC representatives on the scope of the assignment to the PC.

The preliminary conclusion on Inclusion I5 is that all Reactive Resources should be required to be in the Bulk Electric System (BES) regardless of size. While this represents the status quo, a technical rationale for this decision still needs to be provided.

e. RAS – Phil Fedora

The Reliability Assessment Subcommittee (RAS) is researching the generation threshold issues. Phil Fedora distributed a Power Point presentation prior to the meeting that was utilized to direct the discussion.

RAS is looking at several options for the capacity question and everything is still on the table.

The SDT reminded Phil Fedora to make sure that RAS maintains the 100 kV connection criteria in their work.

2. **Review of FERC NOPR and Discussion of Response Plan – Pete Heidrich**

   The Notice of Proposed Rulemaking (NOPR) was issued on June 22, 2012 but won't be official until it is published in the Federal Register. Responses to the NOPR must be submitted within 60 days of publication in the Federal Register. The result was favorable but several clarifications have been requested and the responses to these requests could influence the final order. NERC Legal will make the official response for NERC to the NOPR but the SDT has been requested to provide responses to the technical questions. In order to let NERC Legal have enough time to do what they need to do for the submittal, the SDT will need to supply their responses in approximately 30 days.

   A small sub-group of the SDT will draft straw man responses to all of the pertinent questions (Rules of Procedure questions will need to be answered by the ROP Team). The sub-group consists of Pete Heidrich, Barry Lawson, Rich Salgo, Jennifer Sterling, Bill Harm, and Ed Dobrowolski. When the straw man responses are complete, they will be distributed to the SDT only for review which will be finalized on a group conference call.

   Anyone can respond to the NOPR.

3. **Review of Guidance Document**

   The document was not completed due to time constraints but the majority of the document was available for review.

   NERC Legal reviewed the opening paragraphs and provided comments which have been incorporated into the draft.

   On page 2, the 3 step process cited there doesn't really apply to all of the diagrams so it should be deleted. This is due to the adopted philosophy that the individual diagrams should be restricted to showing only those items pertinent to the part of the definition they are explaining, i.e., diagrams for Exclusion E1 should be providing guidance on Exclusion E1 and not other inclusions or exclusions which are handled in their respective parts of the document. However, this points out the need for a new section where the 3 step process is shown so that users can see how to step through the process in real world situations.

   Figure numbers will be shown on all diagrams.

   The Inclusion I1 diagrams will be simplified to only show transformers and no other 'peripheral' equipment. Both 2 and 3 winding examples should be included.

   Starting with Inclusion I2, the terms 'unit' and 'Element' should be deleted in favor of wording from the inclusion itself.

   While there are on-going discussions as to the extent of Inclusion I4, for the Phase 1 guidance document, collector systems are not included. There should be separate diagrams for wind (a.c.) and solar (d.c.).

   The text in Inclusion I5 needs to be made consistent with the other sections of the document.

Exclusion E1 diagrams should emphasize the point of connection. A statement should be added in the front of the document that protection systems and equipment are not shown as they are covered in specific standards and not pertinent to the BES definition. There should be a second diagram to show the normally closed switch condition immediately following the normally open switch diagram.

Parking lot items to be added to standing agenda:

- Point of connection for radial systems
- Necessity for separate Exclusion E1c

The SDT still needs to describe net capacity for Exclusion E2. John Hughes and Tim Soles volunteered to draft a straw man by July 6, 2012 for delivery to the CRWG for consideration. RFC, ERCOT, FRCC, and SERC have already provided input to this effort. Jonathan Hayes will report back for SPP.

AI – Jonathan Hayes to report back on net capacity considerations at SERC.

AI – John Hughes and Tim Soles will draft a straw man description of net capacity by July 6, 2012.

Exclusion E3 needs to emphasize the points of connection. The transformers need to be greater than or equal to on the low side. Line voltages should be identified and then copied to the high-side of the transformers with a note stating that these are simply sample voltages. The bus at the top of the diagram needs to be fixed.

The SDT agreed that no diagrams are needed for Exclusion E4. However, the discussion pointed out the Inclusion I5 diagrams need a note stating that it is assumed there are no Exclusion E4 situations in the diagrams.

4. **Definition Clarification Items**

   a. Non-retail generation (SAR) - Complete

   b. Inclusion I4 (SAR) - Dispersed generation vs. distributed resources

   c. Flowgates in Exclusion E3 (AECI)

      The current language only references monitored Flowgates and doesn't mention the contingent elements. AECI raised the question of whether this was correct. The SDT agreed that the reference should be to both monitored and contingent and made appropriate changes to the language of Exclusion E3 for Phase 2. This item is now complete.

   d. Ownership in Exclusion E4 (AECI)

      AECI questioned whether ownership was a factor in the determination. Entities could own and operate Reactive Resources for retail customers that aren't behind-the-meter. The

SDT agreed and drafted revised language but did not finalize it. Further discussion is needed before this item is marked as complete.

e. Dedicated step-up transformer in Inclusion I2 (PEPCO)

The described scenario is unique and best suited for the exception process. This item is now complete.

Items 'f' through 'i' need research to show the exact problem before they can be discussed. This will be provided for the next meeting.

f. Normally open designation in Exclusion E1 (WECC)

g. Gross or net ratings (ACES)

h. Retail Load, Retail Generation, and Retail Meter (ISONE)

i. Reactive resources in Exclusions E1 and E3

Items 'j' and 'k' were not discussed due to time constraints.

j. Relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693

k. Appropriate 'points of demarcation' between Transmission, Generation, and Distribution

The 2 items marked as 'Parking Lot' in Section 3 of this document will be added to the standing agenda.

5. **Phase 2 Schedule**

With the assurances from the PC that they will meet the December deadline, the project is on schedule at this time.

6. **Next Steps**

With the issuance of the NOPR, it is now time to move forward with the posting of the guidance document for industry comment. Pete Heidrich will make the corrections agreed upon at this meeting and issue the document to the BES SDT for one final review before posting. This review will be completed through e-mail and will be restricted to corrections of conceptual errors and typos. There will be no further face-to-face discussions prior to the posting as all interpretive and personal issues have been discussed in depth.

7. **Future Meetings**

The next meeting will be in Tucker, GA at Georgia Transmission Corporation (GTC) on July 31 – August 1, 2012 from 8:00 a.m. to 5:00 p.m. local time each day. Details to follow.

8. **Action Item Review**

   The following action items were developed during this meeting:

   - Jeff Mitchell will provide the contact information for PC representatives for the conference call concerning the scope of the assignment to the PC.
   - Ed Dobrowolski will coordinate and set up a conference call between SC leadership and appropriate PC representatives on the scope of the assignment to the PC.
   - Jonathan Hayes to report back on net capacity considerations at SERC.
   - John Hughes and Tim Soles will draft a straw man description of net capacity by July 6, 2012.

9. **Adjourn**

   The Chair thanked Exelon for their hospitality and adjourned the meeting at 4:30 p.m. on Thursday, June 28, 2012.

From: Guy V. Zito
To: rsc
Subject: FW: NERC Announcement: Slides Posted - Technical Conferences on Frequency Response | May 22 and 24, 2012
Date: Friday, May 25, 2012 10:13:40 AM

To complete the below,

NPCC will be following the development of these standards closely and I will keep you informed as requirements are developed.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

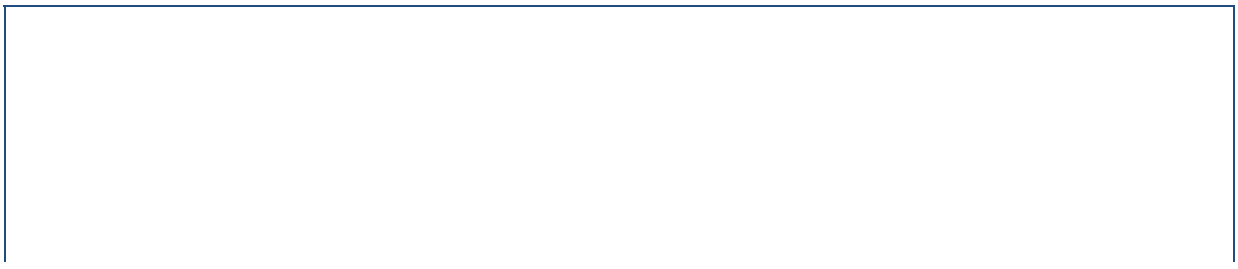
From: Guy V. Zito
Sent: Friday, May 25, 2012 10:12 AM
To: rsc
Subject: FW: NERC Announcement: Slides Posted - Technical Conferences on Frequency Response | May 22 and 24, 2012

RSC,

I listened in on this yesterday. Although the audio at times was inadequate it was very beneficial and will affect our BAs as standards are developed. Work on the BARC and Frequency Response SDTs will have some potential far reaching effects and associated costs. The work done to date does seem to support reliablity and justifies those potential costs from a concept level. We will be following the development of t

Guy V. Zito
Assistant Vice President-Standards
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New York, NY 10018
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From: NERC Standards Announcements (Do Not Reply) [NERC-StandardsAnnouncements-DoNotReply@nerc.net]
Sent: Friday, May 25, 2012 9:30 AM
To: Wendy Kinnard
Subject: NERC Announcement: Slides Posted - Technical Conferences on Frequency Response | May 22 and 24, 2012



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Slides Posted

Project 2007-12 Frequency Response
May 22 and 24, 2012 Technical Conferences

The slide presentations are now available on NERC's Website at the following link:

Presentations - Technical Conferences on Frequency Response

For more information or assistance, please contact Darrel Richardson (via email) or at (609) 613-1848 or Wendy Kinnard (via email) or at (404) 446-9735.

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From: NERC Standards Announcements (Do Not Reply)
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Frequency Response Technical Conferences - Comments Requested
Date: Wednesday, May 30, 2012 5:03:08 PM

Standards Announcement

Frequency Response Technical Conferences

NERC recently held two technical conferences on Frequency Response. The first conference was held on May 22, 2012 in Arlington, VA and the second was held in Denver, Colorado on May 24, 2012. The purpose of these conferences was to obtain industry input on the development of a Frequency Response standard. The information provided in the conferences primarily dealt with the following three areas.

1. The work that has been done on the standard to date
2. Which Functional Entity should be responsible for Frequency Response.
3. How to measure Frequency Response

A complete set of presentations from the conferences can be found at the following link.

http://www.nerc.com/filez/standards/Frequency_Response-RF.html

NERC is requesting industry comments pertaining to the information provided in the conferences or suggestions for further consideration in the development of a Frequency Response standard. Please share your thoughts on the Technical Conference and the associated subject matter by providing your comments using the electronic comment form.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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GO Perspective on Frequency Response Resources

NERC FR Conferences

Chris Schaeffer, Sr Engineer, Duke Energy

Chair of EPRI Power Plant NERC Standards MOD Tech Focus Group

NERC Mandated Data Communication

What - Generator Capability (MW and MVARs), Transformer Data, Generator Dynamic Data, Speed Governor Characteristics, Aux System Load Requirements

When – Annual Updates, but Significant Capability Changes Requires Immediate Reporting such that operating models can be revised

Transmission Department Processes that depend on system model Information, such as normal operations, planning, etc

Transmission System Model Data

Generation Plant Data

Generation Department process that impact system model Information, such as plant changes, operating limitations, validation tests, new plants, etc

Complications

- NERC historically a Transmission focus except for Markets. GO/GOP began to focus after 2007.
- Many different industry structures (vertically integrated vs. IPP/TO) - who is really responsible for what?
- In market based structure, cost cutting, no incentive to maintain equipment expertise - Plants get paid for MWhs. Will follow mandatory NERC standards but maintaining expertise current with evolving issues not considered economic.
- Grids not designed to common “standards”.
- Communication between TO and GOP is hampered by oversensitivity to code of conduct and standards repercussions, especially where an IPP may compete with native generation.
  - This should not be an issue with Frequency Response but...

Recent Trends

- Plant engineering, design, construction and modification outsourcing - less involvement of engineers with understanding of grid issues – not many available.
  - Engineering companies use young (less expensive resources). Minimal graduates in Power Systems. Issues not typically covered in industry initiatives, such as EPRI plant training.
  - No link of recent grid standards with plant design standards (i.e. IEEE, EPRI URD).
  - Controls engineers do not understand “Response Obligations”
- New NERC Focus groups – EPRI and NAGF – no “grid” INPO
- Standard new plants w/o considering local design needs – interconnection studies must identify issues prior to approval.
  - Recent NAGF question – what standard plant features are needed?

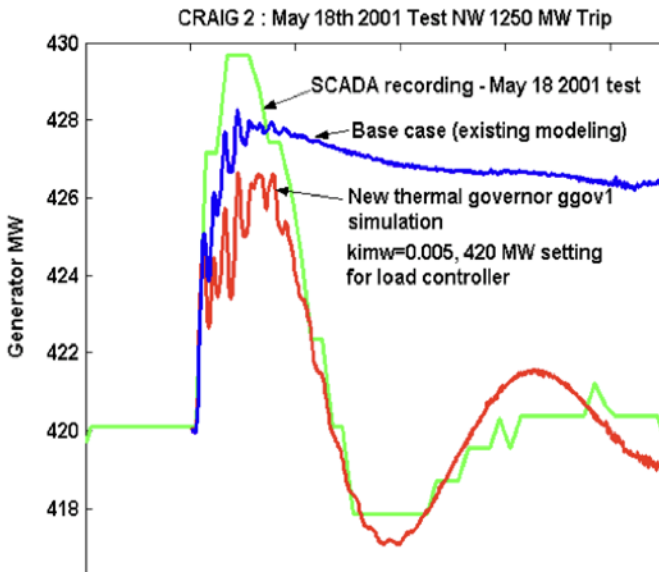
Long Term Legacy (Prior to Mandatory Standards)

- Different MW power sources lead to different technical issues

- Good engineering (ME) ≠ Good engineering (EE). Full operating MW capability of old coal plants may be > designed MW (Prated) in assumed in models.
  - Over time, replacement of worn out turbines with new, more efficient components , tuning steam cycle operating efficiencies based on new knowledge
  - May operate well above original rated MW power levels and thus may be “FR Limited” due to actually operating continuously at the Pmax and Valves wide open (VWO).
  - Boiler output not changed thus, were not considered planned uprates.

Frequency Response and Governors

- Generator MW output responsiveness to Frequency changes
- Early models assumed all units can be modeled as responsive using droop and deadband – invalid assumptions continue which has caused us to miss the big picture - how a unit MW output can be expected to change with frequency.
- Individual Response obligations not well understood
  - Desired response is 1% for 2 minutes?
- Digital governor Max Power Limits
- Plant control system over-rides gov response
- Terminology is key. Ask a GO/GOP
  - How will unit respond to Freq.?
  - Not What is your governor droop and deadband?



Problem – Understanding generator frequency response

- Differences in terminology used by plant vs. model engineers (typically software based), e.g.
  - SERC Regional Criteria – Most utilities employ Power Technologies Inc. (PTI) Power System Simulator for Engineering (PSS/E). Consequently, the various activities in the procedural manual incorporate PTI's procedures and nomenclature in describing these activities. GO's do not speak this language.
- Models didn't consider VWO, max power limits, etc.
- Lack of clear definitions and use of different terminology for modeled generation assumptions and terms creates confusion on what is needed
  - New NERC Standards and Glossary do not align

Inconsistent standards terms

- NERC Glossary Term Normal and Emergency Rating, however
  - MOD-024 MW - Verification of Generator Gross and Net Real Power Capability
    - Now moved to MOD-25 after industry comments that this is not needed – more confusion
  - MOD-027 - To verify that the turbine/governor and load control and active power/frequency control model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, that accurately represent generator unit real power response to system frequency variations.
- Need consistent terminology understood by both sides

P-max – Is this “Emergency” Rating?

- Pmax – The maximum MW output that is expected to be available in a system emergency and be produced by governor response to frequency dips.
- Plant control system should allow for automatic frequency response if possible. If appropriate, Pmax might = Gross Continuous Capability (GCC – MOD-024 - e.g. the unit has no frequency response capability).
  - Hydro units can accept short periods of cavitations without significant shortening of turbine blade life
    - may be able to provide
    - control system design needs to support – define what is needed?
  - Units with Valves Wide Open could respond if operated below Pmax, but would need to continuously sacrifice MWs to have that ability - what is the incentive/cost for them to do so?
  - Gas plants could use emergency limits, but operation would exceed operating temp limits, shortening time frames to significant rebuild costs – what is the incentive for them to do so?
  - Nuclear units could respond above 100%, but likely would have to change plant licensing basis to do so – what is the incentive for them to do so.

Staged Governor Parameter Testing

- Conditions during Load Rejection ≠ Conditions during full power operation. Thus, staged testing does not accomplish goal yet discussion still exists to require it. Plants consider this a risky evolution.

- Can validate against ambient data from system response (large loss of generation, a system fault, etc), however, this requires a recorder preinstalled to collect generator MW and frequency during an event, e.g. digital fault recorder (DFR).

- EPRI PPPD Software or equivalent (MatLAB) may perform “parameters tuning” to include load control models.

Suggested Initiatives

- Must transition from Knowledge based to Process based Configuration Control Guidelines
  - What should be considered when plant changes might affect models
  - Revise FAC-8 Documentation
  - Integrated change-based revalidations would best assure models and help develop/maintain needed technical expertise.
    - Unit up-rate activities or generator rewinds
    - MOD-26 validations where appropriate
    - Inertia Changes due to Turbine, Generator Rotor or Exciter replacements
    - Include Frequency Response considerations in plant control changes

Suggested Initiatives

- Consensus MW power terms in Glossary, such as
  - Normal (GCC) vs. Pmax Rating
  - Desired Response (obligations) – 1% for 2 minutes?
  - Pmax that respects plant limitations - NRC imposed limits, Thermal Limits (CTs), Operating Valves Wide Open
  - Ramp Rates – how fast can a unit transition from Normal to Emergency Rating if governor response calls for increases.
- Need to be clearly understood and supported by plant design if plant frequency response will be optimized
- NATF initiative for model guidelines with standard definitions.
- GO/GOP Training on System Issues
  - EPRI & NATF collaborate to develop?

Research “Smart” Tools - UNCC ARPA-E Application

- Develop Optimized Platform for System Analyses, Model Configuration Control and Validations to Support Bulk Electric System (BES) Reliability”
  - Consistent definitions, research Generation Aux system load models and transient ride through (PRC-024)
  - On line model tool that can monitor system response though DFR data and alarm when models don’t match. (PPPD model validation on steroids) - AVR/Exciters, Speed Governor, Load Models and Transformers?
  - Integrated analysis tool that can be used to perform all analyses (LF, TS, SC, Real Time, etc) to minimize and simplify database management.
  - Study system and unit/plant controls (Power load Unbalance, MW setpoints, area control actions, generation control loops) within and beyond the transient stability timeframes between 15-25 seconds.
  - Research will be integrated into the UNCC EPIC Engineering curriculum to train the next generation power system workforce.
  - Contact Dr Salami @ UNCC EPIC Center if interested in learning more about concept



QUESTIONS?

From: Wendy Kinnard
To: Wendy Kinnard
Subject: UPDATE: NERC Announcement: Technical Conference on Frequency Response | May 24, 2012
Date: Tuesday, May 22, 2012 4:06:17 PM

Announcement - Update

Project 2007-12 Frequency Response Technical Conference

May 24, 2012| 9:00 a.m. to 5:00 p.m. MT
Xcel Energy Office
Denver, CO

Based on stakeholder interest, NERC is providing observers the capability to view and listen to this conference remotely.

Click here for web registration

Dial-in U.S. & Canada: 866.740.1260 | Access Code: 9473885
List of global toll-free numbers

Test your computer here for compatibility prior to the meeting.
For technical support: U.S. and Canada: 800.843.9166 | International: 303.209.1600
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Background: Frequency Response, a measure of an Interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load, is a critical component to the reliable operation of the bulk power system, particularly during disturbances and restoration. Failure to maintain frequency can disrupt the operation of equipment and initiate disconnection of power plant equipment to prevent them from being damaged, which could lead to wide-spread blackouts. There is evidence of continuing decline in Frequency Response over the past 10 years, but no confirmed reason for the apparent decline.

The purpose of this conference is the development of a Frequency Response standard. Topics that will be reviewed and discussed are as follows:

Frequency Response & Frequency Bias Setting Basics

- Presentation and Panel Q&A
  - Presenter: Howard Illian, Energy Mark, Inc.
  - Presenter: Robert Cummings, North American Electric Reliability Corporation

- Don Badley, Northwest Power Pool
- Gerry Beckerle, Ameren

The Need for a Frequency Response Standard

- Presentation and Panel Q&A
  - Presenter: Robert Cummings, North American Electric Reliability Corporation
  - David Lemmons, Xcel Energy

Explanation of the Current Version of BAL-003-1

- Presentation and Panel Q&A
  - Presenter: Terry Bilke, Midwest Independent System Operator
  - Sydney Neimeyer, NRG Energy
  - Sandip Sharma, ERCOT
  - David Lemmons, Xcel Energy

Minimum Frequency Bias Setting

- Presentation and Panel Q&A
  - Presenter: Howard Illian, Energy Mark, Inc.
  - Don Badley, Northwest Power Pool
  - Terry Bilke, Midwest Independent System Operator
  - Robert Cummings, North American Electric Reliability Corporation

The Responsible Entity for Providing Frequency Response

- Overview Presentation
  - David Lemmons, Xcel Energy
- Interactive Panel Discussion
  - David Lemmons, Xcel Energy
  - Clyde Loutan, California Independent System Operator
  - Chris Schaeffer, Duke Energy
  - Don Tench, Consultant

Measurement of Frequency Response

- Overview Presentation
  - Terry Bilke, Midwest Independent System Operator
- Interactive Panel Discussion
  - Terry Bilke, Midwest Independent System Operator
  - Howard Illian, Energy Mark, Inc.
  - Sydney Niemeyer, NRG Energy
  - Robert Cummings, North American Electric Reliability Corporation

For more information or assistance, please contact Darrel Richardson (via email) or at (609) 613-1848 or Wendy Kinnard (via email) or at (404) 446-9735.

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COM-003-1

Operating Communications Protocols White Paper

May 2012

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Introduction

Communication (COM) Standard COM-003-1 features requirements, the purpose of which is to provide clear, formal and universally applied communication protocols that reduce the possibility of miscommunication that could lead to action or inaction that is detrimental to the reliability of the Bulk Electric System (BES). Significant events have occurred on the BES when unclear communication created or exacerbated misunderstandings that led to instability and separation. Communication protocols used in many industries, militaries and government departments have added clarity to oral and written communications and have prevented potential errors that would have resulted in catastrophic events.

Purpose

The Operations Personnel Communications Protocol Standards Drafting Team (OPCP SDT) drafted a Standard Authorization Request (SAR) for Project 2007-02. The purpose of the proposed standard is to: "Require that real time System Operators use standardized communication protocols during normal and emergency operations to improve situational awareness and shorten response time."

The purpose of this paper is to establish the reliability value of requiring three-part communication for all operations on the BES described in the proposed definition of COM-003 - 1 "Operating Communications." Additionally, it addresses the reliability benefit of other communication protocols featured in COM 003-1 that provide addition clarity for "Operating Communications."

Background

NERC Project 2007-02 was created from the 2003 Blackout Report, Recommendation 26. In April 2004, the "Blackout Report" was submitted to the President of the United States of America and the Prime Minister of Canada.

The Blackout Report stated that:

> "Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during alerts and emergencies, is essential to reliability."

The report also recommended that industry,

> "Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate."

FERC Order No. 693, Paragraph 532 directs the ERO and the industry to develop communication protocols based on the following guidelines:

> "532. While we agree with EEI that EOP-001-0, Requirement R4.1 requires communications protocols to be used during emergencies, we believe, and the ERO agrees, that the communications protocols need to be tightened to ensure Reliable Operation of the Bulk-Power System. We also believe an integral component in tightening the protocols is to establish communication uniformity as much as practical on a continent-wide basis. This will eliminate possible ambiguities in communications during normal, alert and emergency conditions. This is important because the Bulk-Power System is so tightly interconnected that System impacts often cross several operating entities' areas."

In response to this recommendation in FERC Order No. 693, a SAR team was established in April of 2007. These reports, directives and approved guidance documents provide the framework from which the OPCP SDT derived the concepts that contributed to the development of the COM-003-1 requirements.

Three-Part Communication

Overview

Three-part communication, sometimes known as the "repeat back" method of communications, is used to communicate changes to physical Facility equipment during work activities via face-to-face, telephone, or radio communications. This communication protocol requires three oral exchanges between a sender and a receiver to promote a reliable transfer of information and understanding. The person originating the communication is the sender and is responsible for verifying that the receiver understands the message, as intended. The receiver makes sure he or she understands what the sender is saying and repeats back the message to the sender.

Steps for Three Part Communication

COM-003-1 requires the use of three-part communication for "Operating Communications," which is defined as, "Communication of instruction to change or maintain the state, status, output, or input of an Element[1] or Facility[2] of the Bulk Electric System."

This is a general description of how three-part communication functions:

1. First - The sender orally transmits information (face-to-face, telephonic or other electronic equivalent) clearly and concisely to the receiver, directing them to alter an element that could impact the BES.

2. Second - The receiver orally acknowledges the communication by repeating the message back to the sender. The receiver does not need to repeat every part of the communication verbatim, but he or she must restate the equipment-related information exactly as spoken by the sender. If the receiver does not understand the message, he or she must ask for clarification.

3. Third - The sender acknowledges the reply and confirms to the receiver that the message is correct and properly understood by stating the communication was correct. If the sender does not understand the receiver's reply, the sender must then respond by saying, "That is wrong," (or words to that effect) and then restate the original message. If corrected, the receiver must acknowledge the corrected message and repeat back the message to the sender.

[1] In the NERC Glossary of Terms, Element is defined as, "Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components."

[2] In the NERC Glossary of Terms, Facility is defined as "a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"

Verbal three-part communication should be used during the operation or alteration of Facility equipment. Applicable entities are to use three-part communications when performing steps or actions using an approved procedure that impact equipment or activities, the safety of personnel, the environment, or the Facility. Finally, three-part communication should be implemented for tasks where the consequences of a mishap are unacceptable and could lead to instability, uncontrolled separation, or Cascading.

As a best practice, it may also be used when discussing the condition of Facility equipment or the value of an important parameter in utility operations.

Phonetic Alphabet or Alpha-numeric Clarifiers

Overview

Several letters in the English language sound alike and can be confused in stressful or noisy situations. For example, some letters sound alike when spoken, and can easily be confused; such as “D” and “B.” The phonetic alphabet specifies a common word for each letter of the English alphabet. By using a word for each letter, there is less chance that the person listening will confuse the letters. Using the phonetic alphabet, “Delta” and “Bravo” are more easily differentiated. The effects of noise, weak telephone or radio signals, and an individual's accent are reduced through the use of the phonetic alphabet.

People use the phonetic alphabet and unit designators when describing unique identifiers for specific components. When the only distinguishing difference between two component labels is a single letter, then the phonetic alphabet form of the letter should be substituted for the distinguishing character. For example, 2UL-18L and 2UL-18F would be stated, “two Uniform Lima dash one eight Lima” and “two Uniform Lima dash one eight Foxtrot.”

COM-003-1 Featured Phonetic Alphabet

Letter - Word	Letter - Word	Letter - Word	Letter - Word
A - Alpha	H - Hotel	O - Oscar	V - Victor
B - Bravo	I - India	P - Papa	W - Whiskey
C - Charlie	J - Juliet	Q - Quebec	X - X-ray
D - Delta	K - Kilo	R - Romeo	Y - Yankee
E - Echo	L - Lima	S - Sierra	Z - Zulu
F - Foxtrot	M - Mike	T - Tango	
G - Golf	N - November	U – Uniform	

Number	pronounced as:	Number	pronounced as:
1 - One	(wun)	6 - Six	(six)
2 - Two	(too)	7 – Seven	(sev-en)
3 - Three	(tree)	8 – Eight	(ait)
4 - Four	(fow-er)	9 – Nine	(nin-er)
5 – Five	(fife)	0 – Zero	(zee-row)

The phonetic alphabet or a correct alpha-numeric clarifier is to be used for any, “Communication of instruction to change or maintain the state, status, output, or input of an Element or Facility of the Bulk Electric System.”

COM-003-1 Operating Personnel Communication Protocols

The nature of communication between people can be complex and subject to many variables. Accents, moods, regional jargon, cultural interpretations, multiple languages, individual skill sets, and physiological conditions are but a few of the universe of factors that can and do have an impact on the clarity of two-party, person-to-person communication. Until the human factor is completely eliminated, there will be the risk of human error due to miscommunication.

Miscommunication has created unintended results on the Bulk Electric System (BES) that have led to outages and, in some cases, the inability of an operator to prevent the spread of Cascading. Although the potential for human error can never be completely eliminated, successful, proven communication protocols from other industries that also deal with critical processes and systems can be implemented to reduce the risk to BES reliability. The successful implementation of these widely-accepted communication protocols from other industries into the requirements of COM-003-1 will have a significant, positive impact on the reliability of the BES.

COM-003-1 requires the use of three-part communication for all Operating Communications. The reliability benefits of using three-part communication is threefold:

1. The removal of any doubt that communication protocols will be used and when they will be used. This will reduce the opportunity for confusion and misunderstanding among entities that may have different doctrine. An example is: One entity uses three-part for emergencies, and the other uses it for all operating conditions.

2. There will be no mental "transition" when operating conditions shift from normal to Emergency. The communication protocols for the operators will remain standard during transitions through all conditions.

3. The formal requirement for three-part communication will create a heightened sense of awareness in operators that the task they are about to execute is critical, and recognize the risk to the reliable operation of the BES is increased if the communication is misunderstood.

Electric Utility Industry Communication Practices

The risk of BES failure due to miscommunication is very significant in the electric power industry. Blackouts that affect millions of customers in major cities are guaranteed to create undesirable media attention. The public at large in North America is heavily dependent on technology and is intolerant of massive blackouts. The public is conditioned to 24/7 access to technology, climate control and lighting. A sudden loss of service quickly causes immediate public frustration. If the root cause was determined to be industry operating miscommunication instead of uncontrollable environmental factors, criticism increases even more dramatically. Other industries that currently deal with risks, challenges and potentially widespread consequences similar to the electric utility industry have successfully reduced miscommunication by implementing uniform communication protocols similar to those identified in and required by COM 003-1.

Table of Communication Practices of the Electric Utility Industry

The examples listed in the table below represent the communication practices of many major registered entities that engage in three part communication when altering the operating state of the BES. These registered entities account for a large amount of the generation, load and customers served in North America.

Table 1-A Registered Entities that Currently Use Three-Part Communication during Both Emergencies and Non-emergencies[3]

Registered Entity Location and Description	Generation Operations	Transmission Operations	Distribution Operations	Normal Operations	Emergency Operations	Customers Impacted	Load
South/Central US Entity (large)	Yes	Yes	Yes	Yes	Yes	23 Million	82 GW
Large Southern Entity #1	Yes	Yes	Yes	Yes	Yes	4.4 Million	43 GW
Large Mid Atlantic RTO Entity	Yes	Yes	NA	Yes	Yes	60 Million	185 GW
Large Southern Entity #2	Yes	Yes	Yes	Yes	Yes	2.8 Million	30 GW
Large West Coast Entity#1	Yes	Yes	Yes	Yes	Yes	5.1 Million	Not Available
Large Canadian HYDRO	Yes	Yes	Yes	Yes	Yes	1.3 Million	27 GW
Large	Yes	Yes	Yes	Yes	Yes	3.4	17 GW

[3] Industry use of three part communication analysis is based on publicly published documents, policies, procedures and internal standards.

Registered Entity Location and Description	Generation Operations	Transmission Operations	Distribution Operations	Normal Operations	Emergency Operations	Customers Impacted	Load
Midwestern/ Western Utility						Million	
Large Florida TOP	Yes	Yes	Yes	Yes	Yes	4.5 Million	43GW
Midwestern RTO Entity	Yes	Yes	NA	Yes	Yes	39 Million	110 GW
DOE	Yes	Yes	Yes	Yes	Yes	NA	NA
INPO	Yes	Yes	Yes	Yes	Yes	NA	NA

This is strong evidence of an embedded electric utility practice that establishes, without doubt, the significant element of reliability value of three-part communications and the other communications protocols. The fact that the majority of BES entities already employ three-part (or repeat back) communications for routine, alert and Emergency operations (and document it in very strong language in their policy and procedures) demonstrates that the electric utility industry recognizes this significant element of value.

Human Factor Considerations

As previously discussed, there are a myriad of reasons that miscommunications occur. Beyond the typical environmental concerns (loud background noise, radio static, dialects, etc.), humans are very likely to have misunderstandings based on other factors. Humans are susceptible to expectation errors, relating to context and meaning, which will often drive understanding. People often discern what they want to hear, usually at a subconscious level. The importance of verifying what is heard becomes the first step in assuring that the message was understood.

When a person hears a message, an interpretation emerges from the different pieces of conversation data; this is called data-driven or bottom-up processing. Perception can be largely data-driven because one wants to make sure their understanding accurately reflect events in the outside world; in this case, the message from the sender. A person wants the interpretation of a message to be determined mostly by data (perception), then to understand the information in the environment (comprehension), and to make the appropriate decision from the senses; not by the listener's expectations. This data-driven processing can lead to miscommunications and may affect situational awareness because if the perception of the information is wrong, the chances of correct understanding and making proper future decisions are dramatically reduced.[4]

Situation awareness is fundamentally based on one's understanding of a system, how it operates, its characteristics, and performance parameters; couplings within itself and other systems and how one interacts with it. This understanding is referred to as one's mental model. It is a representation of the surrounding world, the relationships between its various parts and a person's intuitive perception about his or her own actions and their consequences. One's mental model helps to shape one's behavior and define one's approach to solving problems (a personal algorithm) and carrying out tasks, especially within a system. Mental models can be partially or completely right or wrong, complete or incomplete, and most often are unique for each individual. Sometimes mental models are carried throughout an organization through operating norms and commonly understood practices. Part of building a mental model for a particular problem or event is to gain information through active communication with others. Miscommunication can hamper immediate decisions and can also lay in waiting as a latent error, which can expose itself later when the incorrect information is retrieved or used in the processing of decision making.

[4] Endsley, M. R. (1995). Toward a theory of situation awareness in dynamic systems. Human Factors, 37(1), 32-64.

Communication Practices External to the Electric Utility Industry

The purpose of effective communication is to create mutual understanding between two or more people. Effective communication is an important defense in the prevention of errors and events. Many industries mandate communication protocols due to the high potential for catastrophic results if an important communication is misunderstood. While the effects of critical mishaps from ineffective communications differ, the offending organization and associated industry will find itself dealing with legal, regulatory, financial, market and political consequences.

Medical Field Industry

Ineffective communication is a root cause for nearly 66 percent of all sentinel events (events that signal the need for immediate investigation and response) reported in the medical industry. In other words, 66 percent of all reported deaths or serious injuries (accidents) in healthcare from 1995-2005 were related to ineffective communication.[5]

One step the medical industry is implementing to solve ineffective communication problems in the healthcare industry is to implement a "read-back" process for taking verbal or telephone orders.

Oral communication possesses a greater risk of misunderstanding compared to written forms of communication. Misunderstandings are most likely to occur when the individuals involved have different understandings, or mental models, of the current work situation or use terms that are potentially confusing. Therefore, confirmation of verbal exchanges of operational information between individuals must occur to promote understanding and reliability of the communication. In addition, the medical industry is standardizing abbreviations, acronyms, and symbols used throughout the field, to include compiling a list of those abbreviations, acronyms, and symbols that are not to be used.

Commercial Air Transportation Industry

Based on available data, in the last 67 years there have been 274 commercial airline accidents involving at least 60 fatalities or more. Miscommunication between pilots and controllers can clearly be identified as a causal factor in 36 (13 percent) of these tragedies. Based on this analysis, the aviation community has implemented interpersonal communication tools like three-part communications and language standardization.

[5] JCAHO1 Root Causes and Percentages for Sentinel Events (All Categories) January 1995–December 2005.

Military Communication Protocols

Military organizations have a long history of communication protocols that they have developed and have improved over time. Firing orders, shipboard orders to the helm, aircraft launch and recovery contain elements of three-part communication and alpha numeric clarifiers. The reasons these communication protocols are required are due to the extreme risks and consequences that exist if miscommunication occurs. Military organizations also make use of the NATO alphabet and various shorthand codes to provide a status or update.

Railroad Operations

Rail operations have similar risks of catastrophic results due to miscommunication. Switching rails, moving cars, coupling, decoupling and loading freight necessitate clear communication and require three-part communication and formal protocols.

Other Organizations

Police and fire dispatch, the Department of Energy, and The Institute of Nuclear Power Operations (INPO) are among other organizations that value and mandate communication protocols similar to those in COM-003-01.

Performance of the Electric Utility Industry

Of all of the System events that NERC has either analyzed or investigated, 50 percent of those have involved findings of a deficiency of clear, concise communications. These events have either impacted, or potentially impacted, a significant amount of Load and/or generation.

Significant blackout events, such as the Northeastern Blackout of 2003 and the Florida Blackout of 2008, have communication issues listed among the top contributors to loss of Load and generation.

This analysis highlights the fact that industry Operating Communication performance over the last 10 years still has room for significant improvement. The lack of clear standard communication protocols when operating the BES will continue to create unacceptable levels of risk for large-scale failures.

Table 1 indicates that, across electric power industry, internal policies specify three-part communications for all BES operations, including routine or normal operations. This high level of compliance can be associated with the history of enforcement of COM 002-2a, R2, which requires three-part communication for all directives. This requirement has been mandated and has been enforceable for several years. When compared to COM 002-2a, COM 003-1 features improved approaches and structure for three-part communication that assigns proper responsibility for the "issuer" (sender) and for the "receiver." When combined with the proposed definition of "Operating Communications," COM 003 clarifies the circumstances of when to use three-part communication. The other improvement COM 003-1 offers, to improve the reliability of the BES, is the addition of several proven communication protocols that will clarify Operating Communications to reduce the risk of mistakes Clarifying several key elements of an "Operating Communication;" such as time, time zone, equipment identifiers, a common language and alpha-numeric clarifiers, all contribute to reducing misunderstandings and reduce the risk of a grave error during BES operations.

Summary

The BES across North America is a "tightly" interconnected System where instability can spread quickly. When a decision is made to alter the state of an Element on the BES, there is an increased threat to reliability, no matter what type of operating condition (normal, alert, Emergency) exists. The transition from normal to Emergency operation can be sudden and indistinguishable until recognized, often after the damage is done. There are multiple human factors during communication that occur naturally and contribute to unclear communication, which increases the risk to reliable operation of the BES.

The electric power industry widely deploys communication protocols such as three-part communications for all BES Operating Communications. The uniform deployment of these protocols in the three Interconnections is in part due to Requirement 2 in the mandatory and

enforceable Reliability Standard COM-002-2a. Industry's widespread utilization of three-part communications for BES Operating Communication is a confirmation of the reliability value of the protocol.

The official results of the 2003 Blackout Report cites unclear communications as a major factor in the cause, spread, and impedance of restoration of major BES failures. Other industries have successfully implemented universal communication protocols, which have resulted in fewer accidents and fatalities caused by miscommunications. Preventable blackouts or widespread loss of generation or load continues to be politically, socially and economically unacceptable in North America.

Conclusion

The critical nature of BES configuration and its impact on reliability demands, that any action planned to alter the System under any condition should be systematically and clearly conveyed. Given the extent of human involvement in the process, the risk of miscommunication increases based on our own human tendencies and perceptions.

COM 003-1 takes communication protocols for the BES to the next level of reliability by requiring protocols that will reduce the risk of miscommunication. It clarifies when to use three-part communication. It provides a superior requirement structure that properly assigns the elements of three-part communication to the "issuer" (sender) and "receiver" and requires additional communication protocols that provide greater clarity when engaged in operating communication on the BES. Based on the facts listed above, communication protocols, as contained in proposed Standard COM-003-1, will provide a strong and much improved reliability benefit to address existing communication reliability gaps that continue to negatively impact the reliable operation of the BES.

The proposed communication protocols in COM 003-1 have been successfully developed and proven in other organizations' processes. The use of repeat backs and the added layer of value they provide to BES reliability make them essential to all "Operating Communications." The OPCP SDT endorses the use of these protocols.

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-02 – Operating Personnel Communications Protocols | White Paper on Operating Communications Protocols Posted
Date: Tuesday, May 15, 2012 8:43:51 AM

Standards Announcement

Project 2007-02 – Operating Personnel Communications Protocols
White Paper on Operating Communications Protocols Posted

Now Available

A white paper on Operating Communications protocols has been posted with the clean version COM-003-1 – Operating Personnel Communications Protocols that has been posted for a 45-day formal comment period, initial ballot and non-binding poll. The drafting team prepared this white paper to aid in the evaluation of proposed COM-003-1 and the associated proposed definition of Operating Communication.

Background

NERC Project 2007-02 was created from the 2003 Blackout Report, Recommendation 26. In April 2004, the "Blackout Report" was submitted to the President of the United States of America and the Prime Minister of Canada.

The Blackout Report stated that:

> "Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during alerts and emergencies, is essential to reliability."

The report also recommended that industry,

> "Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate."

FERC Order No. 693, Paragraph 532 directs the ERO and the industry to develop communication protocols based on the following guidelines:

> "532. While we agree with EEI that EOP-001-0, Requirement R4.1 requires communications protocols to be used during emergencies, we believe, and the ERO agrees, that the communications protocols need to be tightened to ensure Reliable Operation of the Bulk-Power System. We also believe an integral component in tightening the protocols is to establish communication uniformity as much as practical on a continent-wide basis. This will eliminate possible ambiguities in communications during normal, alert and emergency conditions. This is important because the Bulk-Power System is so tightly interconnected that System impacts often cross several operating entities' areas."

The purpose of the white paper is to establish the reliability value of requiring three-part communication for all operations on the BES described in the proposed definition of COM-003 -1 "Operating Communication." Additionally, it addresses the reliability benefit of other communication protocols featured in COM 003-1 that provide addition clarity for "Operating Communication."

The requirements in COM-003-1 also support one of the eight high priority issues identified in the NERC President's Top Priority Issues for BPS Reliability Issued January 7, 2011:

> Ambiguous or incomplete voice communications – Out of longstanding tradition, system operators and reliability coordinators are comfortable with informal communications with field and power plant personnel and neighboring systems. Experience from analyzing various events indicates there is often a sense of awkwardness when personnel transition from conversational discussion to issuing reliability instructions. It is also human nature to be uncomfortable in applying formal communication procedures after personnel have developed informal styles over many years. Confusion in making the transition from normal conversation to formal communications can introduce misunderstandings and possibly even incorrect actions or assumptions. Further, once the need to transition to more formal structure is recognized, the transition is often not complete or effective. Results can include unclear instructions, confusion whether an instruction is a suggestion or a directive, whether specific action is required or a set of alternative actions are permissible, and confusion over what elements of the system are being addressed.

The drafting team is in the process of preparing for a webinar on the proposed COM-003-1. The webinar is scheduled to be held on Thursday June 7, 2012 from 1:30—3:30 p.m. Eastern Daylight Time. An announcement for the webinar with additional details is forthcoming.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development and interpretation processes. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Industry Webinar – Draft Standards COM-003-1 and COM-002-3

Project 2007-02 Operating Personnel Communication Protocols Standard Drafting Team

Project 2006-06 Reliability Coordination Standard Drafting Team

June 7, 2012

RELIABILITY | ACCOUNTABILITY






NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda

- Welcome, Introductions and Administrative – Joseph Krisiak, NERC
- Opening Remarks – Lloyd Snyder, GSOC, OPCPSDT Chair
- COM-003-1 Overview, Highlights of Draft 2 Changes – Lloyd Snyder
- COM-002-3 Overview of Draft 6 – Mike Hardy, Southern Company, RCSDT Chair
- COM-002-3 and COM 003-1: Past and Present – Lloyd Snyder
  COM-002-3 and COM 003-1: Schedule – Joseph Krisiak
- Comment and Ballot Process – Joseph Krisiak
- Questions and Answers – Moderated by Joseph Krisiak

COM-002-3 and COM-003-1

- Today's important takeaways!
  - Clarify the scope and intent of each standard
  - Demonstrate the merit of each standard
  - Clarify how each standard will apply communication protocols and address reliability under different operating conditions
  - Discuss the need to have both standards approved in order to preclude a potential reliability gap



COM-003-1 Overview

COM-003-1 Draft 2 Addresses

- The 2003 Blackout Report
  - "Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during alerts and emergencies, is essential to reliability."
  - The report also recommended that industry: "Tighten communications protocols, especially for communications during alerts and emergencies."

COM-003-1 Draft 2 Addresses Continued

- FERC Order 693, P532
  - Directs the ERO and the industry to develop communication protocols based on the following guidelines:
    - "532. While we agree with EEI that EOP-001-0, Requirement R4.1 requires communications protocols to be used during emergencies, we believe, and the ERO agrees, that the communications protocols need to be tightened to ensure Reliable Operation of the Bulk-Power System. We also believe an integral component in tightening the protocols is to establish communication uniformity as much as practical on a continent-wide basis. This will eliminate possible ambiguities in communications during normal, alert and emergency conditions. This is important because the Bulk- Power System is so tightly interconnected that System impacts often cross several operating entities' areas."

COM-003-1 Draft 2 Addresses Continued

- The 2007 COM-003-1 Standard Authorization Request
  - This Standard Authorization Request requires the development of communications protocols for use by real-time system operators “during normal and emergency operations to improve situational awareness and shorten response time.”

COM-003-1 Draft 2 Addresses Continued

- One of the eight high priority issues identified in the NERC President's Top Priority Issues for Bulk Power System Reliability Issued January 7, 2011: [1]
  - Ambiguous or incomplete voice communications – Out of longstanding tradition, system operators and reliability coordinators are comfortable with informal communications with field and power plant personnel and neighboring systems.
  - Experience from analyzing various events indicates there is often a sense of awkwardness when personnel transition from conversational discussion to issuing reliability instructions. It is also human nature to be uncomfortable in applying formal communication procedures after personnel have developed informal styles over many years.

[1] http://www.nerc.com/fileUploads/File/News/NERC%20President%20Top%20Priority%20BPS%20Reliability%20Issues%201-7-11.pdf

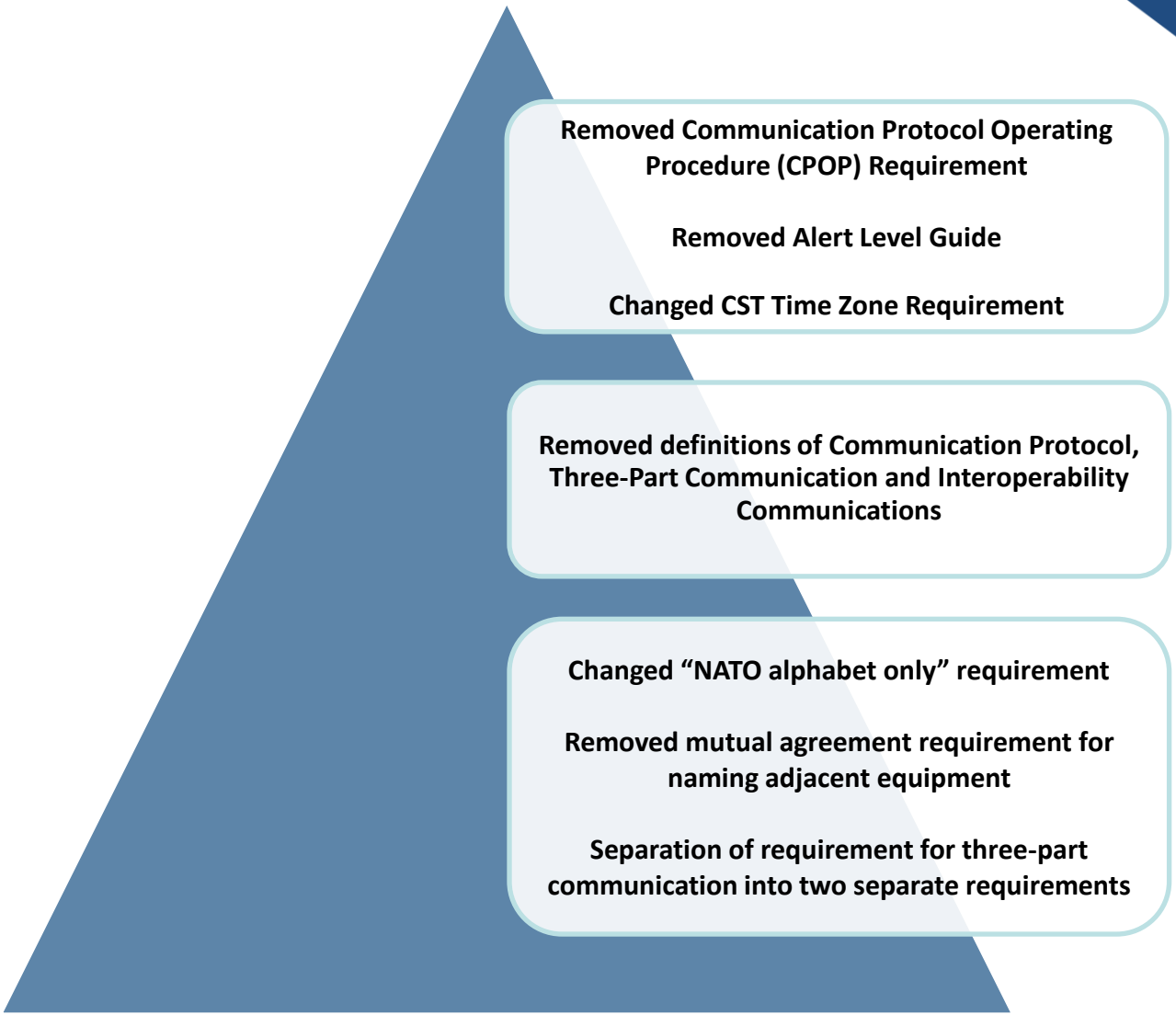
COM-003-1 Draft 2 Addresses Continued

- Confusion in making the transition from normal conversation to formal communications can introduce misunderstandings and possibly even incorrect actions or assumptions. Further, once the need to transition to more formal structure is recognized, the transition is often not complete or effective.
- Results can include unclear instructions, confusion whether an instruction is a suggestion or a directive, whether specific action is required or a set of alternative actions are permissible, and confusion over what elements of the system are being addressed.



COM-003-1 Highlights of Draft 2 Changes

Changes from Draft 1 COM-003-1



Removed Communication Protocol Operating Procedure (CPOP) Requirement

Removed Alert Level Guide

Changed CST Time Zone Requirement

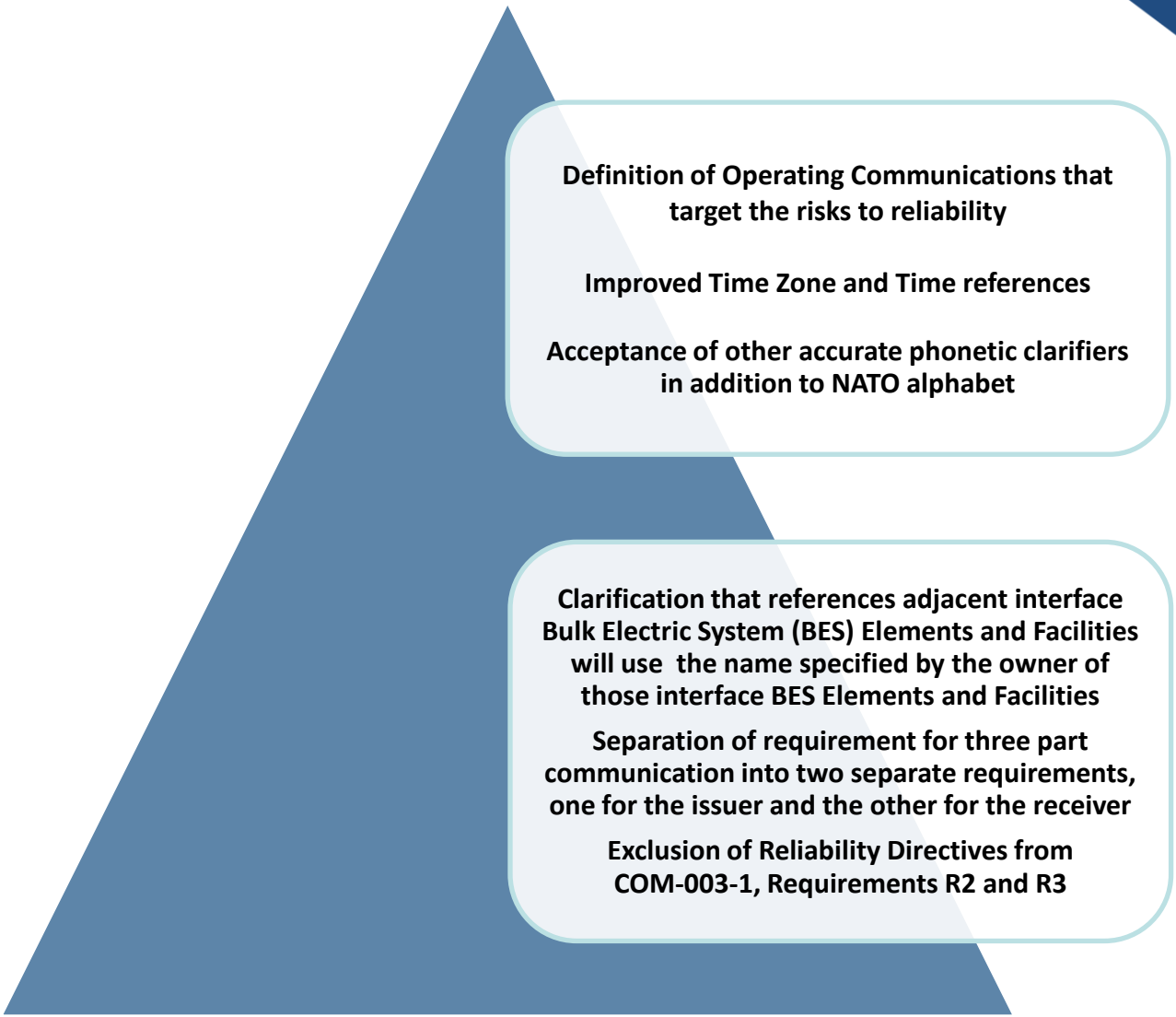
Removed definitions of Communication Protocol, Three-Part Communication and Interoperability Communications

Changed “NATO alphabet only” requirement

Removed mutual agreement requirement for naming adjacent equipment

Separation of requirement for three-part communication into two separate requirements

Features of Draft 2 COM-003



Definition of Operating Communications that target the risks to reliability

Improved Time Zone and Time references

Acceptance of other accurate phonetic clarifiers in addition to NATO alphabet

Clarification that references adjacent interface Bulk Electric System (BES) Elements and Facilities will use the name specified by the owner of those interface BES Elements and Facilities

Separation of requirement for three part communication into two separate requirements, one for the issuer and the other for the receiver

Exclusion of Reliability Directives from COM-003-1, Requirements R2 and R3

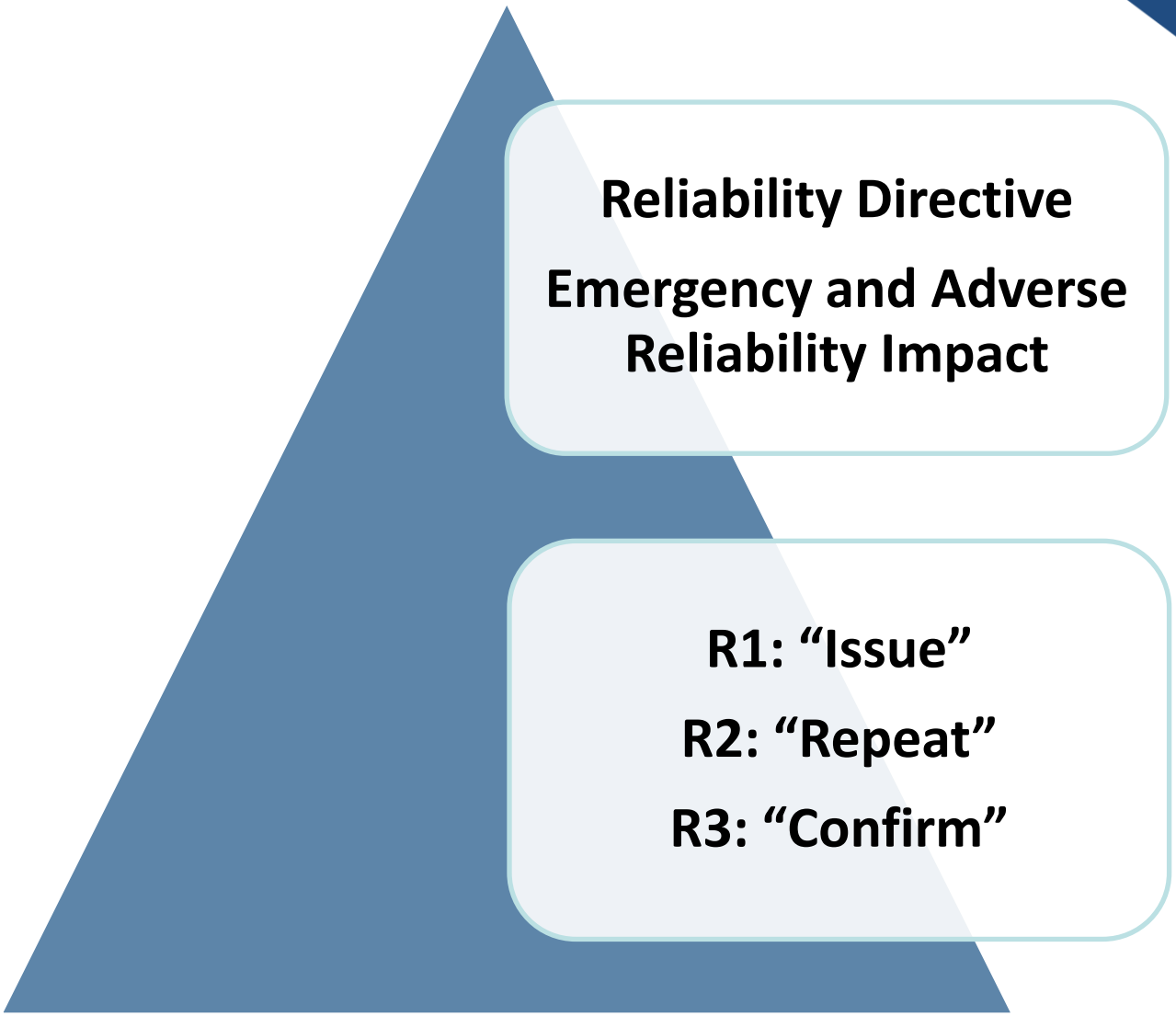
COM-003-1 Violation Risk Factors/Violation Severity Levels

- All Violation Risk Factors (VRFs) are Medium
- No Binary Violation Severity Levels (VSLs)
- R1 – Medium, High and Severe VSLs
- R2 and R3 – High and Severe VSLs



COM-002-3 Overview Draft 6

Features of COM-002-3



Reliability Directive

Emergency and Adverse Reliability Impact

R1: “Issue”

R2: “Repeat”

R3: “Confirm”



COM-002-3 and COM-003-1: History

COM-002-3 and COM-003-1

- Background
  - The two standards were developed by two separate Standard Drafting Teams (SDTs)
    - COM-003-1 (Project 2007-02) by the OPCPSDT
    - COM-002-3 (Project 2006-06) by the RCSDT
  - The original plan was to have COM-003-1 absorb the requirements of COM-002-3 after formal filing approval
  - Both projects moved at different paces and evolved in response to stakeholder comment

COM-002-3 and COM-003-1

- Background (continued)
  - COM-003-1 focused on operating communication protocols as they apply to all operating conditions
  - COM-002-3 focused on operating communication during emergency conditions (i.e., Reliability Directive)
  - Starting in November 2009 efforts were made by both teams to coordinate which requirements would be developed by each SDT
  - Both SDTs had justifiably strong convictions and responded to stakeholder comment differently, resulting in the two current complementary drafts



COM-002-3 and COM-003-1: The Present

COM-002-3 and COM-003-1

- Current status
  - COM-003-1, Draft 2 is undergoing a 40-day Initial Comment period and 10-day Initial Ballot both ending June 20, 2012
  - COM-002-3, Draft 6 successfully balloted and the next step will be a Recirculation Ballot
- Potential confusion
  - Both SDTs recognize the potential for stakeholder confusion and surprise based on industry's expectation of how these two standards were to be developed and implemented and how they would function in concert to enhance reliability

COM-002-3 and COM-003-1

- Key attributes of each standard
  - COM-003-1
    - Applies to normal operating conditions
    - Features Medium VRFs and gradated VSLs
  - COM-002-3
    - Applies to potential and actual Emergency operating conditions
    - Features High VRFs and binary VSLs

COM-002-3 and COM-003-1

- Coverage
  - Application of COM-003-1, R2 and R3 establishes BES communication protocols under normal operating conditions
  - Application of COM-003-1, R2 and R3 ceases when actions are to be executed as a "Reliability Directive" in accordance with COM-002-3, under Emergency operating conditions
  - Application of COM-003-1, R2 and R3 is reestablished when normal operating conditions return to the BES
  - The two standards together cover "Operating Communications" for all operating conditions

COM-002-3 and COM-003-1

- Coverage (continued)
  - The two standards appropriately differentiate on risk and severity levels based on the operating conditions on the BES
  - Logically, a compromised BES demands that corrective actions such as Reliability Directives be issued, repeated and confirmed accurately to reduce the risk of further degradation to an already compromised system
  - Conversely, Operating Communication errors during normal conditions can be a catalyst for actions that would or could undermine the reliability of the BES

Comparative Table

Operating Communications	
Communication of instruction to change or maintain the state, status, output, or input of an Element or Facility of the Bulk Electric System.	
English, 24-hour clock, time-zone, owner's identifier, and alpha-numeric identifiers	
COM-003-1	***COM-002-3***
Normal Communication	***Reliability Directives***
3-Part	***3-Part***

COM-002-3 and COM-003-1

- Operating condition transition
  - The transition from normal to Emergency is not always quickly discerned and the use of the same protocols before, during and after an Emergency would eliminate confusion in making the transition from normal conversation to formal communications
  - The premise is if you use three-part communication effectively during routine conditions it will flow naturally into Emergency operations

COM-002-3 and COM-003-1

- Today's important takeaways!
  - Clarify the scope and intent of each standard
  - Demonstrate the merit of each standard
  - Clarify how each standard will apply communication protocols and address reliability under different operating conditions
  - Discuss the need to have both standards approved in order to preclude a potential reliability gap



COM-003 -1 and COM-002-3: Schedule

Schedule

- COM-003-1
  - First Ballot of Standards – June 2012
  - Successive Ballot of Standards – September 2012
  - Recirculation Ballot of Standards – October 2012
  - Present Standard to the Board of Trustees – November 2012
- COM-002-3
  - First Ballot of Standards – Complete
  - Successive Ballot of Standards – Not required
  - Recirculation Ballot of Standards – June 27 to July 6, 2012
  - Present Standard to the Board of Trustees – August 2012



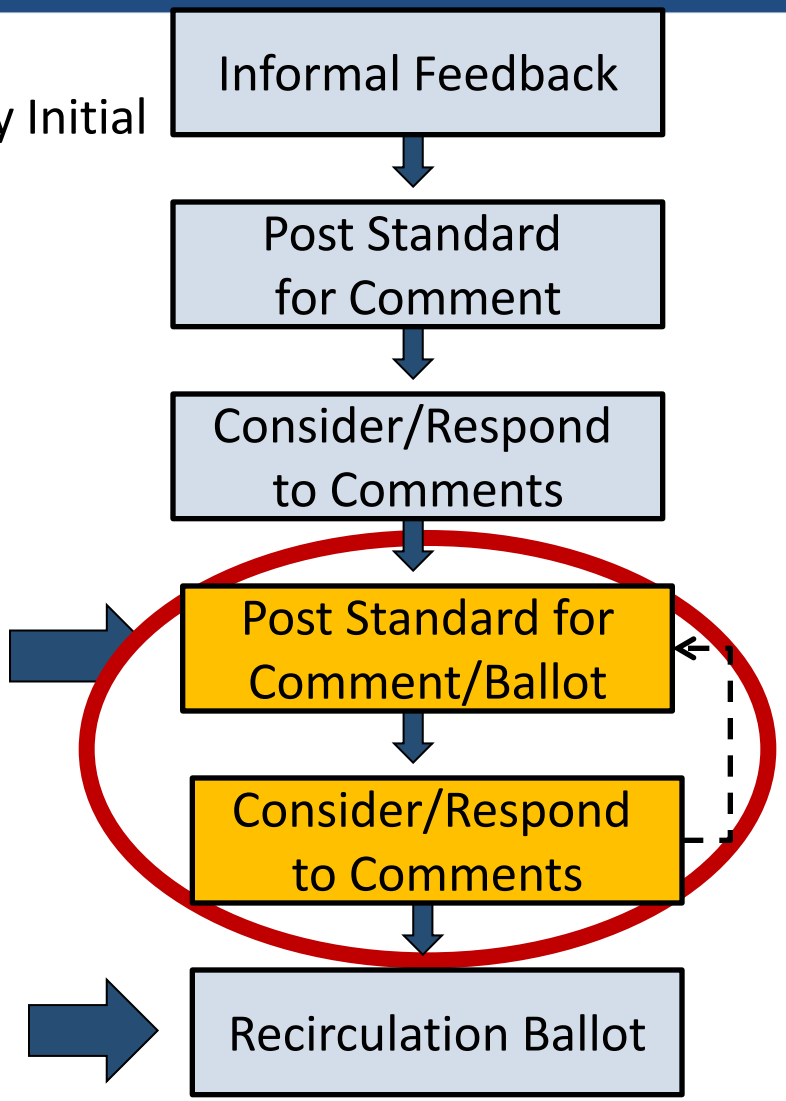
COM-003-1 Comment and Ballot Process

Stakeholder Consensus Process

Posted for 40-day Formal Comment and 10-day Initial Ballot period

New/Successive Ballot:
At this step, the standard is either "new" or significantly changed from the last version posted for comment/ ballot. The ballot record starts with no votes and no comments.

Recirculation Ballot:
At this step, there have been no significant changes to the standard from the last ballot. The ballot record starts with all votes and comments from the previous ballot.



Comment and Ballot Period

- May 7, 2012 through June 20 , 2012
  - Formal 40-day comment period
- June 11, 2012 through June 20, 2012
  - Initial Ballot and Non Binding Poll open
    - Definition
    - Implementation Plan
    - VSLs and VRFs



Navigating Stakeholder Input Toward Consensus

- Stakeholder feedback is essential
- Almost 360 pages of comments and responses
- Very comprehensive comments from last posting
- Drafting team considered all viewpoints



Submitting Comments

- Ballot comments
  - Submit through “checkbox form” – not within ballot
  - No need to submit same comment more than once
- Comments on proposed standards
  - Submit through electronic form
  - Be brief
  - Focus on question asked
  - Indicating agreement with others is preferred over copying the comments (e.g., “ABC agrees with XYZ’s comments...” or “ABC agrees with XYZ’s comments except for…”)

Comment Form

- Unofficial comment form
  - Provided to assist comment development
  - Formatting will not transfer from unofficial form to official form (web-based)
- Warning included on comment form:



VERY IMPORTANT:
Please note that **the official comment form *does not* retain formatting** (even if it appears to transfer formatting when you copy from the unofficial Word version of the form into the official electronic comment form). If you enter extra carriage returns, bullets, automated numbering, symbols, bolding, italics, or any other formatting, that formatting will not be retained when you submit your comments. Therefore, if you would like to separate portions of your comment by idea, e.g., the drafting team requests that each distinct idea in the same comment block be prefaced with (1), (2), etc., instead of using formatting such as extra carriage returns, bullets, automated numbering, bolding, or italics.

Sample Comment Form

1. The SDT modified the requirement for use of the R1 Part 1.2 NATO phonetic alphabet to allow use of another correct alpha numeric clarifier. Do you agree with this modification?

❑*Yes*
❑*No*

2. The SDT modified the requirement R1 Part 1.1.4 for use of identifiers for interface Elements/Facilities only. The identifiers will be assigned by the transmission owner of the Elements/Facilities. Do you agree with this modification?

❑*Yes*
❑*No*

3. Do you agree with the VRFs and VSLs for Requirements R1, R2and R3?

❑*Yes*
❑*No*

4. Do you have any other comments or suggestions to improve the draft standard?

❑*Comments:*

Standard Drafting Team Response Process

- Issues and responses for each individual requirement
- Effective feedback:
  - Specific to question
  - Provide proposed change/rationale
- Less effective feedback:
  - Repeating comment multiple times/responses to entire standard in every question
  - No reference to where suggested change should occur
  - Non-specific concerns, e.g. “I do not like this standard.”

Questions?

- Please submit your questions via the ReadyTalk chat window (please reference slide number)
- Moderator and point of contact – Joseph Krisiak, NERC
  - Joseph.krisiak@nerc.net
- Key dates:
  - May 7, 2012 through June 20, 2012 – Formal Comment Period
  - June 11, 2012 through June 20, 2012 – Ballots Open
- Slides and recording of this webinar will be posted to the NERC website (usually within two business days)

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Industry Webinar – Remaining Q & A

Project 2007-02 Operating Personnel Communications Protocols Standard Drafting Team (COM-003-1)

June 7, 2012

Q: The meaning of Operating Communication keys on the meaning of the word "instruction". Can the SDT clarify the meaning of this word and examples of it?
A: The term instruction is used in the context of the word "order" as to order an individual to complete a task for example: *I instructed him to get rid of the trash.*

Q: I'll ask a silly question: how would the COM-003 audit question? Take for example "Will you please open breaker apha-bravo-charlie-one-two-three?"
A: I'm not sure of the context you intend for "Will you please open breaker apha-bravo-charlie-one-two-three?" If it is a question as you indicate by the punctuation it should not be construed as an Operating Communication which would instruct or order an individual. It seems as though the speaker is asking the receiver for permission to *open breaker alpha-bravo-charlie-one-two-three*. If the intent of the speaker was to command the receiver to open the breaker it should be a direct statement of command not an interrogative statement.

Q: You commented that these standards are not intended to apply to distribution systems outside the BES. Why do these versions create requirements for Distribution Providers who do not operate the BES ?
A: The SDT believes the standard applies to Distribution Providers under some circumstances such as instructions to shed load. When DPs are involved with Operating Communications they must be compliant with R1 and R3 of COM-003-1.

Q: COM-003-01: 1.2. When participating in oral Operating Communications and using alpha-numeric identifiers, use accurate alpha-numeric clarifiers.1 -- states "and using alpha-numeric identifiers." Does that give me an out not to use it?
A: No, if the nomenclature of an Element or a Facility includes designators that are alphanumeric identifiers the entity must use alpha-numeric clarifiers to ensure the desired actions are being performed on the proper Element or Facility.

Q: What is the exact role of Generator Operator in this standard? What is the different role between TO and GO? Could TO acting as GO in a utility in this standard? Do you really need GO in this standard?
A: The GO is the Generator Owner and is not an applicable entity in COM-003-1. We are certain you mean the GOP or Generator Operator. The GOP is subject to R1 and R3. R1 requires that when entities are engaged in Operating Communications they will use the Communication Protocols that address key elements that instruct entities to alter the BES. They are subject to R3 because they are receivers of Operating Communications.

Q: Does NERC plan to train the auditors across the 8 regions so there is consistency with compliance audits once the standards discussed today are in effect?
A: Hi Dave. The SDT neither has the authority nor the scope to address this concern. We are comfortable in supporting training and consistency and will pass your concern to our training team.

Q: DPs own and operate 138 kV breakers.
A: That is correct; some, not all DPs actually do own and operate BES equipment.

Q: Please explain what you mean by "observation" being looked at by auditors when voice recording is not available.
A: Observation means actually viewing and listening to operating personnel conduct and direct operations on the BES.

Q: GOPs give internal instructions of when to start and stop generating units.
A: That is correct; they would benefit from compliance with R1 and R3 of COM-003-1

Q: Please consider separating requirements when there is an "or" between two different conditions: "2.2. After the response is received, or if no response is received, do one of the following:..." This can be confusing.
A: We will consider it. Please include it in your comments.

Q: Will BES generator control rooms be required to have voice recording capability to be able to proceed evidence to prove compliance with the standard?
A: The types of evidence would be the same as listed in the standard M2 and M3 - *Evidence may include but is not limited to voice recordings, transcripts of voice recordings, on site observations, or other equivalent evidence.* Voice recordings are absolute and are a primary confirmation and I would say preferable. The other forms listed would be suitable. Are you aware of a BES entity that does not have a voice recording capability?

Q: each violation of com-003 has the potential for a $100k fine. Should an operator use 3 part, but not alpha numeric, this would be a substantial fine
A: It could be depending on numerous circumstances.

Q: The Effective Date of COM-003-1 is 6 months after applicable regulatory approval. Don't you think this is too soon to see 100% compliance to train field personnel and system operators?
A: That is worth review by the SDT. We will discuss this concern and address it in our next posting.

Q: What if field personnel request the system operator change state of a device?
A: The field person is making a request, not issuing an instruction. The operator would either agree or disagree. If the operator agrees he or she will issue the appropriate Operating Communication.

Q: COM-002-3 R1 "...shall identify the action as a Reliability Directive" Must this be done as part of the issuance of the Directive or can entities identify what situations constitute emergencies, ahead of time in their procedures?
A: Yes

Q: This is a repeat - but wanted to be sure I am hearing correctly. - Since Reliability Directives are subsets of Operating Communications - then English, alpha numeric and 24 hour clock applies under COM-003 R1.2 which covers all oral Operating Communications
A: That is correct

Q: How are Distribution Providers subject to the COM-003 standard?
A: The SDT believes the standard applies to Distribution Providers under some circumstances such as instructions to shed load. When DPs are involved with Operating Communications they must be compliant with R1 and R3 of COM-003-1.

Q: Am I correct in my understanding that the use of alpha-numeric's or phonetic numerals only are not an actual requirement but if Operators use them it must be from an accurate source such as NATO's spelling alphabet?
A: The operators shall use them when engaged in Operating Communications and if operators use them they must accurately represent the letter or number intended by the issuer or receiver. The NATO Phonetic alphabet is the most common and widely used worldwide. Commenters from the first draft stated using Baker instead Bravo (NATO) still properly clarifies the letter or numeral in the alpha numeric identifier and that an entity should not be penalized for using Baker. The SDT agreed and permitted the use of other clarifiers as long as they properly represent the letter or number intended.

Q: Regarding your recent response on directives between operators across the room. How would one demonstrate compliance with the standard?
A: The types of evidence would be the same as listed in the standard M2 and M3 - *Evidence may include but is not limited to voice recordings, transcripts of voice recordings, on site observations, or other equivalent evidence.*

Q: so, if it is not applicable to a GOP, then the RC, BA or TOP giving the order (like today) would be non-compliant for no repeat-back?
A: The GOP is excluded from R2 in COM-003-1, but is applicable in R3 (and R1). Normally a GOP would not issue an Operating Communication but could receive one. R3 stipulates the requirement for the receiver which includes compliance with a "repeat back"

Q: The question was around self-certification. Is every phone call going to need to be monitored to ensure compliance?
A: Every Phone call that is an Operating Communication should be monitored.

Q: I've heard many say that this is a "how-to" standard and NERC should provide the "what" not the "how". What is the Standard Drafting Team's response to such comments?
A: The OPCP SDT was chartered to develop Communication Protocols for Operating Personnel. The SDT believes that the second draft of the standard is more focused on "what" protocols to use in specific situations. In addition to three-part communication, the SDT believes the Standard should address other necessary protocols that prevent miscommunication.

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Project 2007-02 Operating Personnel Communications Protocols

Unofficial Comment Form for Standard COM-003-1 —Operating Personnel Communications Protocols

Please **DO NOT** use this form. Please use the electronic comment form located at the link below to submit comments on the proposed draft COM-003-1 Operating Personnel Communications Protocols standard. Comments must be submitted by **June 20, 2012.** If you have questions please contact Joseph Krisiak at Joseph.Krisiak@nerc.net or by telephone at 609-651-0903.

http://www.nerc.com/filez/standards/Op_Comm_Protocol_Project_2007-02.html

Background Information:
Effective communication is critical for Real-time operations. Failure to successfully communicate clearly can create misunderstandings resulting in improper operations increasing the potential for failure of the BES.

The Standard Authorization Request (SAR) for this project was initiated on March 1, 2007 and approved by the Standards Committee on June 8, 2007. It established the scope of work for the Project 2007-02 Operating Personnel Communications Protocols Standard Drafting Team (OPCP SDT). The scope described in the SAR is to establish essential elements of communications protocols and communications paths such that operators and users of the North American Bulk Electric System will efficiently convey information and ensure mutual understanding. The August 2003 Blackout Report, Recommendation Number 26, calls for a tightening of communications protocols. FERC Order 693 Paragraph 532 amplifies this need and applies it to all Operating Communications. This proposed standard's goal is to ensure that effective communication is practiced and delivered in clear language and standardized format via pre-established communications paths among pre-identified operating entities.

The SAR indicated that references to communication protocols in other NERC Reliability Standards may be moved to this new standard. The SAR instructed the standard drafting team to consider incorporating the use of Alert Level Guidelines and three-part communications in developing this new standard to achieve high level consistency across regions. The SDT believes the Alert Level Guidelines, while valuable, belong in a separate standard and has petitioned the Standards Committee to approve the transfer to another standard or to start a separate project.

The standard will be applicable to Transmission Operators, Balancing Authorities, Reliability Coordinators, Generator Operators, and Distribution Providers. These requirements ensure that communications include essential elements such that information is efficiently conveyed and mutually understood for communicating changes to real-time operating conditions and responding to directives, notifications, directions, instructions, orders, or other reliability related operating information.

The Purpose statement of COM 003-1 states: "To specify clear, formal and universally applied communication protocols that reduce the possibility of miscommunication which could lead to action or inaction harmful to the reliability of BES."

Based on stakeholder comments and observations from the Quality Review team, the OPCP SDT made the following changes to COM-003-1:

- **New NERC Glossary terms**:
  The SDT has eliminated the definitions; Communications Protocol, Three-part Communication and Interoperability Communication proposed in the first draft of the standard and added a definition for *Operating Communications*. Operating Communications more accurately defines the broad class of communications that deal with changing or altering the state of the BES. Changes to the BES operating state with unclear communications create increased opportunities fo*r events that could plac*e the BES at an unacceptable risk of instability, separation, or cascading failures.
- **Communication Protocol Operating Procedure (CPOP):**
  The SDT eliminated the CPOP from the standard based on stakeholder comments indicating this is administrative in nature.
- **English Language:**
  The SDT modified the standard (R3 in the first draft of COM-003-1, R1 Part 1.1.1 in the second draft of COM-003-1) to address comments which point out that in some regions, the use of another language other than English may be mandated by law.
- **Pre-defined System Condition Terminology:**
  The Alert Level Guide document was originally prepared by the Reliability Coordinator Working Group (RCWG) in accordance with a U.S./Canada Task Force Blackout Report Recommendation. Recommendation #20 called for the establishment of clear definitions of normal, alert, and emergency operational system conditions, and to clarify the roles, responsibilities, and authorities of Reliability Coordinators and other responsible entities under each condition.

  After many comments and much discussion the SDT believes the Alert Level Guide is better suited in its own standard or in a standard that deals with alert conditions and notification. The content was not related to communication protocols designed to clarify operating communication on the BES. The SDT has petitioned the Standards Committee to approve of a transfer to another standard or to a new standard as it deems appropriate.
- **Time Zone Reference:**
  The first draft of COM-003-1 included a requirement to use Central Standard Time for operating communications (R4) and stakeholders identified that unless people are communicating in different time zones, this requirement may be a distraction. The SDT modified the standard to require inclusion of time zone references only in those situations where communication is between entities in different time zones**.**

- Three-part Communication:
  The first draft of COM-003-1 included a single requirement for use of three-part communication (R5). Several stakeholders noted that three-part communication is being addressed in two standards. While the OPCP SDT originally planned on proposing retirement of COM-002-3, the team has been convinced that keeping three part communication in both COM-002-3 and COM-003-1 has value.
    - The three-part communications in COM-002-3 are limited to Reliability Directives and have a "High" VRF.
    - The three-part communications in COM-003-1 are focused on Operating Communication except for Reliability Directives which are a subset of Operating Communications. The requirements for three-part communications in COM-003 have a "Medium" VRF.

  The OPCP SDT split the three-part communication requirement into two separate proposed requirements; R2 andR3 to address responsibilities of the issuer and of the receiver respectively during Operating Communications. The SDT also clarified that repeat-back does not have to be exactly verbatim; however the message must be accurately conveyed and understood.

- **NATO Alphabet or Correct alpha numeric clarifiers:**
  The first draft of COM-003-1 had a requirement for use of the NATO Alphabet during operating communications (R6). Many stakeholders indicated that the NATO Alphabet is only one way of providing clarity and proposed that other alpha-numeric clarifies should be acceptable. In response the modified the standard to require use of the NATO Phonetic Alphabet or a correct alpha-numeric clarifier when issuing and replying to verbal Operating Communications that involve alpha-numeric information. The revised standard clarifies that the use of another correct alphanumeric clarifier is permitted as long as the content is fully and accurately conveyed. During spoken communications certain sounds become difficult to discern because they are audibly similar. The use of the NATO Phonetic Alphabet or proper phonetically correct clarifiers is not intended for all verbal communications but is required for Operating Communications involving alpha-numeric identifiers. (See Requirement R1, Part 1.2 in the second draft of COM-003-1.)

- **Line and Equipment Identifiers:**
  The first draft of COM-003-1 had a requirement (R7) for use of pre-determined, mutually agreed upon line and equipment identifiers for verbal and written operating communications. Stakeholders indicated that obtaining such agreements was not necessary and recommended narrowing the scope of this requirement. In response, the OPCP SDT modified the scope of the requirement so it only applies to oral and written operating communications involving a Transmission interface Element or Facility and replaced the need for an agreement with use of the name of the Facility/Element specified by the owner of that Transmission interface Element or Facility. (See Requirement R1, Part 1.1.4 in the second draft of COM-003-1.)

- **VSL and VRF Changes from version one:**
  The OPSDT reviewed the VRFs and VSLs associated with R1, R2 and R3 and made changes to more closely conform to NERC and FERC guidelines. Where the first draft of COM-003-1 proposed having a

"High" VRF for all real-time communications, the second draft of COM-003-1 proposes a "Medium" VRF for each of the three remaining requirements.

The choice of VRFs was made on the basis of the potential impact on the Bulk Electric System of a miscommunication during Operating Communications. Requirements R1, R2 and R3 are assigned a Medium Violation Risk Factor – a violation of one of these requirements, by itself, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but a violation by itself would not lead to Bulk Electric System instability, separation, or Cascading failures.

The VSLs in the second draft of COM-003-1 are all new.

The drafting team is posting the standard for industry comment for a 45-day comment period.

The Operating Personnel Communications Protocols Drafting Team would like to receive industry comments on this draft standard. Accordingly, we request that you include your comments on this form by **June 20, 2012**.

*Please use the **electronic comment form** to submit your final comments to NERC.*

1. **Do you agree with the addition of "Operating Communication" as a proposed new definition for the NERC Glossary and the elimination of "Communication Protocol," "Interoperability Communication" and "Three part Communications" proposed in the first draft of COM-003-1?**

   Operating Communication: Communication of instruction to change or maintain the state, status, output, or input of an Element or Facility of the Bulk Electric System.

   If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The proposed Operating Communication term is not markedly different from the originally proposed term (Interoperability Communication). The proposal continues to expand the scope of the SAR from the concept of tightening the protocols associated with Emergencies by now applying to all communications.

   The text box in the draft standard indicates that Reliability Directives are a type of Operating Communications, to the extent they change or maintain the state, status, output, or input of an Element or Facility of the Bulk Electric System. There is little difference between the two terms despite the SDT's assessment that Reliability Directive is a type (or a subset) of Operating Communication.

   If the intent is to use the proposed new term to require three-part communication (as suggested in R2 and R3), then that intent can be accomplished by using the term Reliability Directive as it covers not only the emergency state but also instructions needed to address Adverse Reliability Impacts.

   Both the Blackout Report and the FERC directive deal with tightening protocols for Emergencies. The proposed requirements completely fail to address emergencies and focus solely on developing non-emergency protocols.

2. **The SDT eliminated the requirement to have a Communications Protocol Operating Procedure from the proposed standard because it is administrative in nature. Do you agree with this modification? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: An alternative approach would be to introduce communications protocols as a mandatory non-standard (e.g. as a requirement for certification) that would center on a corporate communications manual that encourages three-part communications; and that includes how monitoring would be audited internally. Such an alternative would change the requirement from monitoring personnel mistakes to a requirement monitoring corporate culture.

3. **The SDT has proposed to transfer the requirement to use Alert Levels in Attachment 1 to another more closely aligned standard or to a separate new standard. Do you agree with this transfer? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments:

4. **The SDT modified the standard to allow an exemption from the requirement to use English language where the use of another language is mandated by law or regulation. (See Requirement R1, Part 1.1.1) Do you agree with this modification? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

   A general suggestion for all reliability standards that has been made is that standards' requirements be eliminated that do not address reliability problems. No available information indicates that language is causing reliability problems. In the absence of such evidence that this is a reliability problem, consideration should be given to eliminating this requirement.

5. **The SDT modified the standard to mandate utilization of a 24 hour clock for all times and to mandate the use of a time zone and indicate whether the time is daylight saving time or standard time reference when Operating Communications occur between different time zones. (See Requirement R1, Part 1.1.3) Do you agree with this modification? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: This requirement is outside the scope of the approved SAR which proposes responding to the Blackout Recommendation to tighten communications protocols especially during emergencies. This proposed requirement is both procedural and does not address tightening communications of situational awareness.

As an alternative a standard could require the Functional Entities to have a communications protocol that could indeed include this, but it should not be a requirement on personnel. By adopting an alternative category (i.e. not making this a standard) a Reliability Entity could adopt a progressive best practice approach without concern for violating the strictest features of the proposed best practice.

6. **The SDT modified the requirement for use of three-part communications for Operating Communications to clarify that this is not applicable for Reliability Directives and split the single requirement into two requirements: one for the issuer (R2) and another for the receiver (R3). Do you agree with this modification?**

☐ Yes

☒ No

Comments: There are a number of references appearing that state “excluding Reliability Directives”. If Reliability Directive is going to be defined in a separate project (Project 2006-06), how will stakeholders understand what is really being excluded for the purposes of this Standard’s scope? It also needs to be made clear when an action is a Reliability Directive. Will each entity be required to define what is to be included as a Reliability Directive?

With the definition of Operating Communication, three-part communications is expanded to include communications beyond directives, communications that might not warrant governance by this Standard.

The proposed exception (specifically Reliability Directives used during emergencies) does not support the reason the SAR was proposed--to improve protocols during emergencies.

The term Operating Communications is not significantly different from the term Reliability Directives (see comments to Q1). Using the term Reliability Directives to support the requirements for 3-part communication can avoid (a) any confusion with the requirement in COM-002-3, (b) potential double jeopardy of violating both COM-002 and COM-003, and (c) the need to exercise 3-part communication for routine operating instructions.

Suggest consider removing the term Operating Communications. Are Requirements R2 and R3 needed if Reliability Directives already cover non-emergency conditions (instructions/actions that are needed to address potential Adverse Reliability Impact)? The requirement to exercise three-part communication to handle Reliability Directives is thus duly addressed in COM-002-3. It hasn't been shown that three-part communication is necessary for routine operating instructions.

Realistically the definition of Operating Communications covers all communications. Only Reliability Directives should require three-part communications, and should be enforceable if a miscommunication results in an error on the BES.

7. The SDT modified the requirement for use of the NATO phonetic alphabet to allow use of another correct alpha numeric clarifier. (See Requirement R1, Part 1.2.) Do you agree with this modification?

☐ Yes

☒ No

Comments: What determines whether a clarifier used is an "accurate alpha-numeric clarifier"? What dictates non-compliance? This is a procedural issue. The Standard should require the Functional Entities to have a communications protocol that could include this, but it should not be a standard on personnel.

Complexity is being added to communications, not improvement. There are equipment designations that are commonly used and understood, and to force the use of clarifiers will disrupt operating communications.

8. The SDT modified the requirement for use of identifiers to limit the applicability to operating communications involving Transmission interface Elements/Facilities and to require use of the name for that Element/Facilities specified by the Element/Facility's owner(s). Do you agree with this modification?

☐ Yes

☒ No

Comments: The applicability of this Standard is unclear in the case of Distribution Providers. The definition of Operating Communication includes “Elements” that could impact the BES. The NERC Glossary definition for Elements includes non-BES devices and equipment. Additionally, the Purpose section of the Standard states "harmful to the reliability of the BES." Since non-BES Elements could affect the BES this Standard could be deemed applicable to non-BES devices. If it is the intent of the SDT to apply this Standard to All Operating Communications concerning both BES and non-BES Facilities this should be explicitly stated in the applicability section for transparency. Otherwise clarifying language should be added to exclude non-BES Facilities.

This is a procedural issue. Suggest that the Standard should require the Functional Entities to have a communications protocol that could indeed include this suggestion, but it should not be a standard on personnel.

9. Do you agree with the VRFs and VSLs for Requirements R1, R2 and R3?

☐ Yes

☒ No

Comments: The white paper discusses many non-utility industries use of the three-part communication. However, they are not out of compliance if they fail to use three-part communications. Only the Reliability Directives should require three-part communications (and dictate compliance). This should be enforceable only if the miscommunication results in an error on the BES.

We support the use of three-part communications with limitations. There is concern over the potential for being out of compliance when there is no BES impact. Failure to meet Requirement R2, part 2.2 bullets 1 or 3 is either a Moderate or High. Failure to meet bullet 2 is a Severe VSL. It is not clear why this differentiation was adopted. The White Paper reflects on Human Performance, and how miscommunications can cause a BES error resulting in an outage, or possible cascading effects. Then the Standard (and the associated out of compliance) should apply when, and to the extent that communications lapse (e.g., when there is an impactful violation of bullets 1, 2 and/or 3) results in an impactful error on the BES. Otherwise, an out of compliance is inappropriate. Non-impactful violations should be rated “Lower VSL.”

10. If you have any other comments or suggestions to improve the draft standard that you have not already provided in response to the previous questions please provide them here.

Comments: The three-part communications in COM-003-1 are expanded beyond reliability directives which unnecessarily forces the inclusion of conversations which may be impractical or unnecessary. Good practice dictates that three part communication be used as a tool, but it should not be a requirement.

The Standard is specifying how to accomplish, not just what is required.

"1.1.4 When referring to a Transmission interface Element or a Transmission interface Facility, use the name specified by the owner(s) for that Transmission interface Element or Transmission interface Facility" may create a detriment to reliability. Oftentimes, for switching, TOs have very detailed names for individual elements, devices, equipment which may not translate into the TOP/RC systems. However, it is known what equipment is being talked about. The requirement is unnecessary, unreasonable and burdensome.

The communications protocol to be followed in the event that there is a situation that requires the removal of BES (or any other power system equipment for that matter) from service on an immediate and emergency basis to protect the health and safety of the public and/or an employee/s needs to be addressed. The instructions issued to meet this condition fall under the definition of Operating Communication, but in an emergency situation the time taken for the required repetition could be catastrophic. This also applies to BES (or any other power system) equipment that is in imminent danger of failure, phase angle regulator or transformer tap changer runaway, or other emergency conditions.

This is also true of situations where the BES response to a disturbance results in a facility or facilities being overloaded real time over their STE and LTE ratings, and those facility loadings have to be reduced below their STE and LTE ratings within five and fifteen minutes respectively. The time spent for the necessary three part communication could mean the difference between maintaining continuity of service, or having to shed load.

Suggest that wording be added to address the emergency situations described by recognizing the possibility that an operator might have to respond to a situation by issuing a "one way" order, then have a requirement for after the fact communications which would be informational as to what emergency actions were taken, and then resume normal communications protocols for subsequent actions.

Regarding the wording for the issuer in R2 "…that issues an oral, two-party, person-to-person Operating Communication", and the wording for the receiver in R3 "…that receives an oral two-party, person-to-person Operating Communication", what is the significance of the use of the

comma after “oral” in R2? What is the difference between two-party and person-to-person communication?

Also regarding R2, the Generator Operator should be included as an authority to issue an Operating Communication.

It is not necessary to separate normal and emergency communications into two standards (COM-003, COM-002). One standard should encompass both. But having two Standards, the communication protocols in COM-003 R1 should be incorporated in COM-002.

The proposals expand the scope of the SAR by ignoring communications protocols used during emergencies and focusing on procedures imposed on personnel during normal situations. This standard overreaches into routine operations by requiring three-part communication for all instructions that change or maintain the state, status, output, or input of an Element or Facility of the Bulk Electric System. Because of the real-time frequency of use these instructions, requiring operating personnel to apply a three-part communication procedure for these instructions is unnecessary and can in fact adversely affect reliability. Any requirement for three-part communication for routine operating instructions should be removed.

From:	Guy V. Zito
To:	brian.robinson@utilitysvcs.com; Lee R. Pedowicz; rscmembers; "Joel Charlebois"; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject:	RE: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols
Date:	Friday, May 11, 2012 10:09:40 AM

Brian,

We can discuss this at the next meeting. There is a jurisdictional issue that we have discussed in the past and seems to be continually evolving.

Guy V. Zito
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From: Brian Robinson [mailto:Brian.Robinson@utilitysvcs.com]
Sent: Friday, May 11, 2012 9:35 AM
To: Guy V. Zito; Lee R. Pedowicz; rscmembers; 'Joel Charlebois'; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: RE: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols

It is my understanding that reliability standards are to only be applicable to BES facilities unless otherwise stated in the applicability section of the standard. If it is the intent to apply this standard to non-BES facilities I think a clarification is necessary.

Brian Robinson
Associate
Utility Services

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brian.robinson@utilitysvcs.com

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From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Friday, May 11, 2012 9:27 AM
To: Brian Robinson; Lee R. Pedowicz; rscmembers; 'Joel Charlebois'; donald.e.nelson@state.ma.us;

rjfalsetti@cogeco.ca
Subject: RE: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols

Brian,

I would agree that the standard will reach down into the DP operations. As Mr. Pedowicz always states, everything can impact the BES. Clarification might be beneficial.

Also there is a fundamental issue that I am seeing with this standard. There are a number of references appearing that state "excluding Reliablity Directives". If Reliability Directives is being defined under a separate project, how will stakeholders understand what is really being excluded for the pusposes of this standard's scope?

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212-840-1070
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From: Brian Robinson [mailto:Brian.Robinson@utilitysvcs.com]
Sent: Wednesday, May 09, 2012 3:03 PM
To: Lee R. Pedowicz; rscmembers; 'Joel Charlebois'; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: RE: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols

Good Afternoon,

Comment regarding COM-003:

The applicability of this standard is unclear in the case of Distribution Providers. The definition of Operating Communication includes "Elements" that could impact the BES. The NERC Glossary definition for Elements includes non-BES devices and equipment. Additionally, the Purpose section of the standard states "harmful to the reliability of the BES." Since non-BES Elements could affect the BES this standard could be deemed applicable to non-BES devices. If it is the intent of the SDT to apply this standard to All Operating Communications concerning both BES and non-BES Facilities this should be explicitly stated in the applicability section for transparency. Otherwise clarifying language should be added to exclude non-BES Facilities.

Would you agree?

Thanks,

Brian Robinson
Associate

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From: Lee R. Pedowicz [mailto:lpedowicz@npcc.org]
Sent: Monday, May 07, 2012 11:20 AM
To: rscmembers; 'Joel Charlebois'; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: Comment Form--Project 2007-02 - Operating Personnel Communications Protocols

Good morning.

Attached is a copy of the Comment Form for Project 2007-02 Operating Personnel Communications Protocols posted for comments, and supporting materials. Please let me know your comments by Friday, June 8, 2012. Comments are due to NERC June 20, 2012.

Thanks.

Lee

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The Project 2009-01 Standard Development Team is seeking informal comments on a number of proposed changes to the last version of EOP-004-2. The SDT wishes to gather industry comments and reactions to the proposed changes during the month of July including the NERC webinar scheduled for 2 PM on Monday July 30, 2012. Following the receipt of all comments and reactions, the SDT is meeting on July 31 and August 1 to finalize the standard for the next formal comment and ballot period. Here are the changes being proposed.

1. **The SDT is proposing to leave all reporting requirements of CIP-008 in that Cyber Security standard and is proposing to remove all requirements for Cyber Security reporting from EOP-004-2.**
2. **The Applicability section has been modified to reflect the removal of the Registered Entities associated with the Cyber Security reporting requirements.**
3. **The remaining requirements have been simplified to reflect the needs for reporting of the events listed in Attachment 1. All remaining reporting requirements are 24-hour notice. Words in black text are the requirement language; other colored text is for clarification purposes only.**

R1. Each Responsible Entity shall have an event reporting Operating Plan that includes communication protocol(s) for applicable events listed in, and within the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations based on the event type (e.g. the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, governmental or provincial agencies). Expected intent by the SDT: Similar to today's CIP-001, Registered Entities will have a plan, procedure, or process including contact list(s) for the notification associated with the types of events identified in Attachment 1 for the type of functional registrant they are. Entities, at their choosing, can have one list for all types or can have separate lists for the different types of events. The ERO must be on all contact lists. The organization knows to whom it has obligations to for reporting to the rest of the parties to be notified.

R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in, and within the timeframes specified in, EOP-004 Attachment 1.

R3. Each Responsible Entity shall validate all contact information contained in the Operating Plan per Requirement R1 each calendar year. Expected intent by the SDT: This requirement results from the FERC Directive in Order 693. The SDT has removed the language on drills, tests, and or exercises.

4. **Listed below are the proposed changes to Attachment 1:**

Event	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in the need for actions to avoid a BES Emergency.
Damage or destruction of a Facility	BA, TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action.
Physical threats to a Facility	BA, TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather related threat, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report copper theft unless it degrades normal operation of a Facility.
Physical threats to a control center	RC, BA, TOP	Physical threat to its control center, excluding weather related threat, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a control center.
BES Emergency requiring public appeal for load reduction	Initiating entity is responsible for reporting	Public appeal for load reduction event
BES Emergency requiring system-wide voltage reduction	Initiating entity is responsible for reporting	System wide voltage reduction of 3% or more
BES Emergency requiring manual firm load shedding	Initiating entity is responsible for reporting	Manual firm load shedding ≥ 100 MW
BES Emergency resulting in automatic firm load shedding	DP, TOP	Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or SPS/RAS)
Voltage deviation on a Facility	TOP	Observed voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes

Event	Entity with Reporting Responsibility	Threshold for Reporting
IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)	RC	Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).
Loss of firm load	BA, TOP, DP	Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year's demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA, GOP	Total generation loss, within one minute, of ≥ 2,000 MW for entities in the Eastern or Western Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement
Transmission loss	TOP	Unexpected loss, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing)
Unplanned control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of voice communication capability	RC, BA, TOP	Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more
Complete loss of monitoring capability	RC, BA, TOP	Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (State Estimator, Contingency Analysis) is rendered inoperable.

5. Listed below are the proposed changes to Attachment 2:

a. Reorganized the event lists to match order listed in Attachment 1.

b. Removed "Other"

c. Updated ERO contact information

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form

Project 2009-01 Disturbance and Sabotage Reporting

Please DO NOT use this form for submitting comments. Please use the electronic form to submit comments on the draft standard EOP-004-2. Comments must be submitted by May 24, 2012. If you have questions please contact Stephen Crutchfield by email or by telephone at (609) 651-9455.

You do not have to answer all questions.

1. **The DSR SDT has revised EOP-004-2 by removing Requirement 1, Part 1.4 and separating Parts 1.3 and 1.5 into new Requirements R3 and R4. Requirement R3 calls for an annual test of the communications portion of the Operating Plan and Requirement R4 requires an annual review of the Operating Plan. Do you agree with this revision? If not, please explain in the comment area below.**

   ☐ Yes

   ☒ No

   Comments: Regarding Requirement R3, add the following wording from Measure M3 to the end of R3 after the wording "in Part 1.2.":

   > The annual test requirement is considered to be met if the responsible entity implements the communications process in Part 1.2 for an actual event.

This language must be in the Requirement to be considered during an audit. Measures are not auditable.

Regarding Requirement R4, replace the words "an annual review" with the words "a periodic review." Add the following to R4:

> The frequency of such periodic reviews shall be specified in the Operating Plan and the time between periodic reviews shall not exceed five (5) years.

This does not preclude an annual review in an Entity's operating plan. The Entity will then be audited to its plan. If the industry approves a five (5) year periodic review 'cap', and FERC disagrees, then FERC will have to issue a directive, state it reasons and provide justification for an annual review that is not arbitrary or capricious. Adding the one year "test" requirement adds to the administrative tracking burden and adds no reliability value.

2. The DSR SDT made clarifying revisions to Attachment 1 based on stakeholder feedback. Do you agree with these revisions? If not, please explain in the comment area below.

☐ Yes

☒ No

Comments:

Regarding Attachment 1, language identical to event descriptions in the NERC Event Analysis Process and FERC OE-417 should be used. Creating a third set of event descriptions is not helpful to system operators. Recommend aligning the Attachment 1 wording with that contained in Attachment 2, DOE Form OE-417 and the EAP whenever possible.

The following pertains to Attachment 1:

Replace the Attachment 1 "NOTE" with the following clarifying wording:

NOTE: The Electric Reliability Organization and the Responsible Entity's Reliability Coordinator will accept the DOE OE-417 form in lieu of Attachment 2 if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, Voice: 609-452-1422. Initial submittal by Voice within the reporting time frame is acceptable for all events when followed by a hardcopy submittal by Facsimile or e-mail as and if required.

The proposed "events" are subjective and will lead to confusion and questions as to what has to be reported.

Event: A reportable Cyber Security Incident.

All reportable Cyber Security Incidents may not require "One Hour Reporting." A "one-size fits all" approach may not be appropriate for the reporting of all Cyber Security Incidents. The NERC "Security Guideline for the Electricity Sector: Threat and Incident Reporting" document provides time-frames for Cyber Security Incident Reporting. For example, a Cyber Security Compromise is recommended to be reported within one hour of detection, however, Information Theft or Loss is recommended to be reported within 48 hours.

Recommend listing the Event as "A confirmed reportable Cyber Security Incident. The existing NERC "Security Guideline for the Electricity Sector: Threat and Incident Reporting" document uses reporting time-frames based on "detection" and "discovery." Recommend using the word confirmed because of the investigation time that may be required from the point of initial "detection" or "discovery" to the point of confirmation, when the compliance "time-clock" would start for the reporting requirement in EOP-004-2.

Event: Damage or destruction of a Facility

Threshold for Reporting: revise language on third item to read:

Results from actual or suspected intentional human action, excluding unintentional human errors.

Event: Any physical threat that could impact the operability of a Facility

This Event category should be deleted. The word "could" is hypothetical and therefore unverifiable and un-auditable. The word "impact" is undefined. Please delete this reporting requirement, or provide a list of hypothetical "could impact" events, as well as a specific definition and method for determining a specific physical impact threshold for "could impact" events other than "any."

Event: BES Emergency requiring public appeal for load reduction.

Replace wording in the Event column with language from #8 on the OE-417 Reporting Form to eliminate reporting confusion. Following this sentence add, "This shall exclude other public appeals, e.g., made for weather, air quality and power market-related conditions, which are not made in response to a specific BES event."

Event: Complete or partial loss of monitoring capability

Event wording: Delete the words "or partial" to conform the wording to the NERC Event Analysis Process.

Event: Transmission Loss

Revise to BES Transmission Loss

Event: Generation Loss

Revise to BES Generation Loss

3. The DSR SDT has proposed a new Section 812 to be incorporated into the NERC Rules of Procedure. Do you agree with the proposed addition? If not, please explain in the comment area below.

☐ Yes

☒ No

Comments: The proposed new section does not contain specifics of the proposed system nor the interfacing outside of the system to support the report collecting.

4. Do you have any other comment, not expressed in the questions above, for the DSR SDT?

Comments:

The proposed standard is not consistent with NERC's new Risk Based Compliance Monitoring.

a. The performance based action to "implement its event reporting Operating Plan" on defined events, as required in R2, could be considered a valid requirement. However, the concern is that this requirement could be superseded by the NERC Events Analysis Process and existing OE-417 Reporting.

b. The requirements laid out in R1, R3 and R4 are specific controls to ensure that the proposed requirement to report (R2) is carried out. However, controls should not be part of a compliance requirement. The only requirement proposed in this standard that is not a control is R2.

NERC does not need to duplicate the enforcement of reporting already imposed by the DOE. DOE-417 is a well established process that has regulatory obligations. NERC enforcement of reporting is redundant. NERC has the ability to request copies of these reports without making them part of the Reliability Rules.

Form EOP-004, Attachment 2: Event Reporting Form:

Delete from the Task column the words "or partial".

Delete from the Task column the words "physical threat that could impact the operability of a Facility".

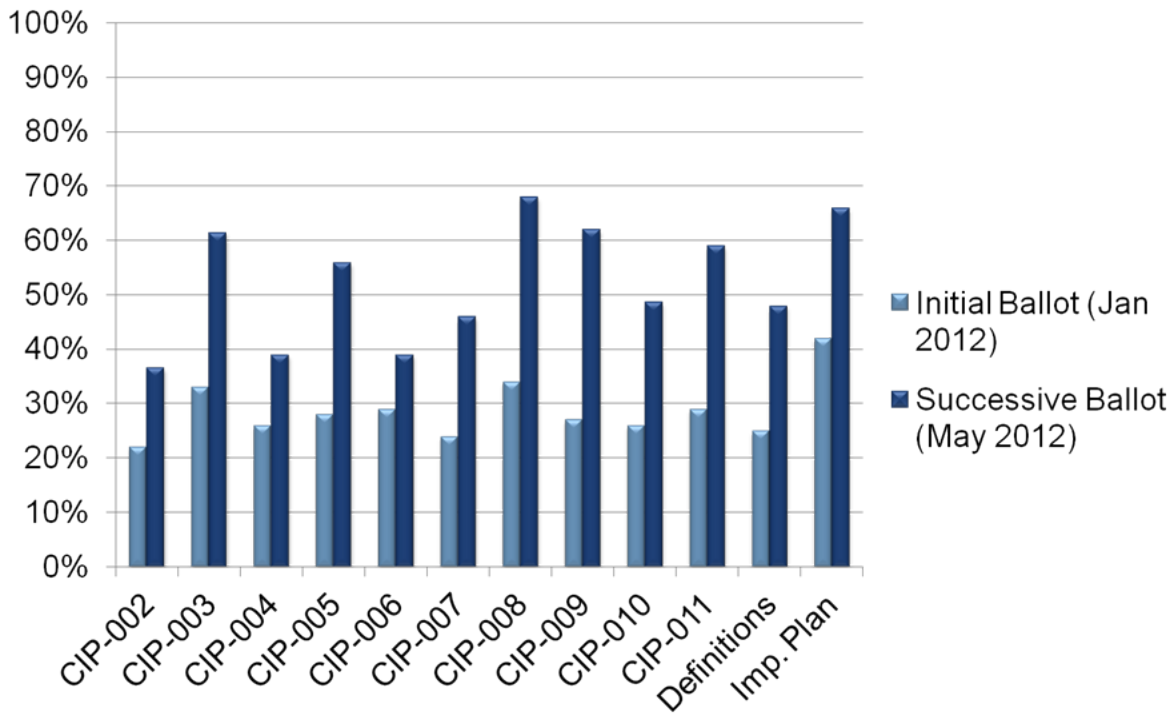
VSL's may have to be revised to reflect revised wording.

From: Guy V. Zito
To: rsc
Subject: FW: NERC CSO 706 SDT: ballot results and June meeting coordination.
Date: Thursday, May 24, 2012 8:06:04 AM
Attachments: image002.png

RSC et al,

Although all failed except for CIP-008, there is significant improvement from the first ballot. CIP-002 will need attention though.

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From: NERC Standards Announcements (Do Not Reply)
To: Wendy Kinnard
Subject: NERC Industry Webinar: Request for Data or Information (Response to Order 754) | June 7, 2012
Date: Tuesday, May 29, 2012 8:10:52 AM

Industry Webinar

Request for Data or Information (Response to Order 754)

June 7, 2012 | 11:00 a.m. to 12:30 p.m. ET

Click here for Webinar Registration
Click here for Order 754 Project Page

Teleconference: 800.736.7549 | **Access Code:** 4469735 | **Broadcast Audio Code:** 577556

Objective
The second draft of NERC's Request for Data or Information applicable to Transmission Planners, Generation Owners, and Transmission Owners was posted for comment on May 11, 2012 concerning the study of single point of failure on protection systems. This 45-day industry comment period as permitted by the NERC Rules of Procedure, Section 1600 allows industry stakeholders to provide comments for consideration prior to requesting NERC Board of Trustees approval in August 2012. This webinar will include valuable background on the events that have led to the data request as well as present the improvements over the first draft. Following the presentation, stakeholders will have an opportunity to submit questions to team members via the chat feature of the webinar.

Background
Order 754 is the Final Rule approving the interpretation of Interpretation TPL-002-0a PacifiCorp (Project 2009-14) regarding requirement R1.3.10. In addition to the approval, the Commission expressed a concern about single point of failure of protection systems and issued a directive for further investigation. Refer to the NERC project page for detailed background information about the directive.

Data Request Process
Section 1600 of the *Rules of Procedure for the Electric Reliability Organization* governs the process for issuing a Request for Data or Information to industry.

For more information or assistance, please contact Scott Barfield-McGinnis (via email) or at (404) 446-9689 or Wendy Kinnard (via email) or at (404) 446-9735.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Industry Webinar
Order No. 754 – Data Request

The Study of Single Point of Failure
Draft 2 Posting

June 7, 2012

RELIABILITY | ACCOUNTABILITY






Introductions

- North American Electric Reliability Corporation (NERC)
  - Scott Barfield-McGinnis, Moderator
  - Howard Gugel, Project Manager
  - Phil Tatro, Technical Advisor
- System Analysis and Modeling Subcommittee (SAMS)
  - Mark Byrd, Progress Energy Carolinas (Chair)
  - Bill Harm, PJM Interconnection, LLC (Member)
- System Protection and Control Subcommittee (SPCS)
  - Jonathan Sykes, PG&E (Chair)
  - Bill Miller, ComEd (Vice Chair)
  - Rich Quest, Midwest Reliability Organization (Member)

NERC Antitrust Guidelines and Public Meeting Disclaimer

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- NERC Disclaimer
  - Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Important Notes

- This webinar, associated slides, and feedback provided in the Question and Answers session are intended to help entities meet their obligations under the Order No. 754 Data Request
- Many slides contain paraphrased information; therefore, entities should always refer to the actual Order No. 754 Data Request document and template for full details

Overview

- Summary of FERC Order No. 754
- Approaches to address the Order No. 754
- NERC Rules of Procedure (ROP), Section 1600
- Draft 2 Modifications
- Data Request Details
- Posted for Informal Comment
- Questions and Answers Session

Summary of Order No. 754

- Order No. 754[1]
  - Commission's approval of Project Interpretation of TPL-002-0b — PacifiCorp (Project 2009-14[2])
  - Commission has a concern (P19)
    - Study of a single point of failure on protection systems
  - Commission issued a directive (P20)
    - FERC staff to meet with NERC and appropriate SMEs
      - Explore the reliability concern
    - NERC to make an informational filing in six months (March 15, 2012)
      - Explain whether there is a further system protection issue and, if so:
      - What forum to address the issue?
      - What priority based on current initiatives?

[1] http://www.ferc.gov/whats-new/comm-meet/2011/091511/E-4.pdf

[2] http://www.nerc.com/filez/standards/Project2009-14_Interpretation_TPL-002-0_PacifiCorp.html

Approaches

- Approaches decided at the October 24-25, 2011 Technical Conference held at FERC
  - Data Request – A small group should develop a proposal to the joint SPCS/SAMS committees
  - Interpretation Request – A small group should develop a proposal to the joint SPCS/SAMS committees
  - Project 2009-07 – To be considered later after the review of the first two bullets above

NERC ROP

- Section 1600 – Request for Data or Information
  - Authority
    - FPA, Section 215
    - FERC, Section 39.2(d) regulations
  - Criteria
    - Describe why data is needed, its use and collection method
    - Identify the functional entity(ies)
    - Estimate of the burden on reporting entities
    - A schedule for reporting
    - Must not have a compliance use
  - Posting for Comment (45 days)
  - Board of Trustee Approval Required

Data Request Goals

- Meet the criteria of Order No. 754 and NERC ROP, 1600
  - Avoid “Compliance” space
  - Assess the burden on entities
- Establish a clear data collection process
- Obtain quality data
  - Sufficient sample size
  - Data across all voltages > 100 kV
  - Define potential concern:
    - Potential impact on system performance
    - Risk based on attributes of protection systems

Data Request Needs

- Identify whether there is a reliability concern associated with the assessment of single points of failure on protection systems
- Enable NERC to:
  - Assess whether there is a reliability concern, and if so
  - Determine whether it is related to specific protection system components
- Cover the following subjects:
  - Responsibility
  - Method
  - Rationale
  - Schedule and Data Reporting



Data Request Draft 2

Draft 2 Modifications

- Extended the reporting timeline
- Included Distribution Provider
- Revised the method (provided an alternative option)
  - Simplified and clarified:
    - Table A: Criteria for Buses to be Tested
    - Table B: Protection System Attributes to be Evaluated
    - Table C: Performance Measures
    - Table D: Station DC Supply Attributes to be Reported
- Additional Rationale, Examples, and Figures
- Provided more detail regarding the Burden to Entities
- New reporting schedule

Timeline

- Extension is responsive to comments
- Extended from 12 to 24 months
- Includes a tiered approach by voltage class
- Rationale
  - Focus first on protection systems which may have the greatest impact on reliability
  - Allow for better integration into transmission planning assessment cycle
  - Aid in resource allocation
  - Provide additional time for fiscal budgeting

Entities

- Reporting entity
  - Transmission Planner (TP)
- Supporting entities
  - Distribution Provider (DP)
  - Generator Owner (GO)
  - Transmission Owner (TO)
- Rationale for adding DP
  - Distribution Providers may own:
    - Transmission lines operated at 100 kV or higher
    - Step-down transformers that step voltage down from a voltage 100 kV or higher to a voltage below 100 kV

Method – Step 1

- Each Transmission Planner will develop a "List of Buses to be Tested," including each bus[9] in its transmission planning area that meets the criteria in Table A, "Criteria for Buses to be Tested."

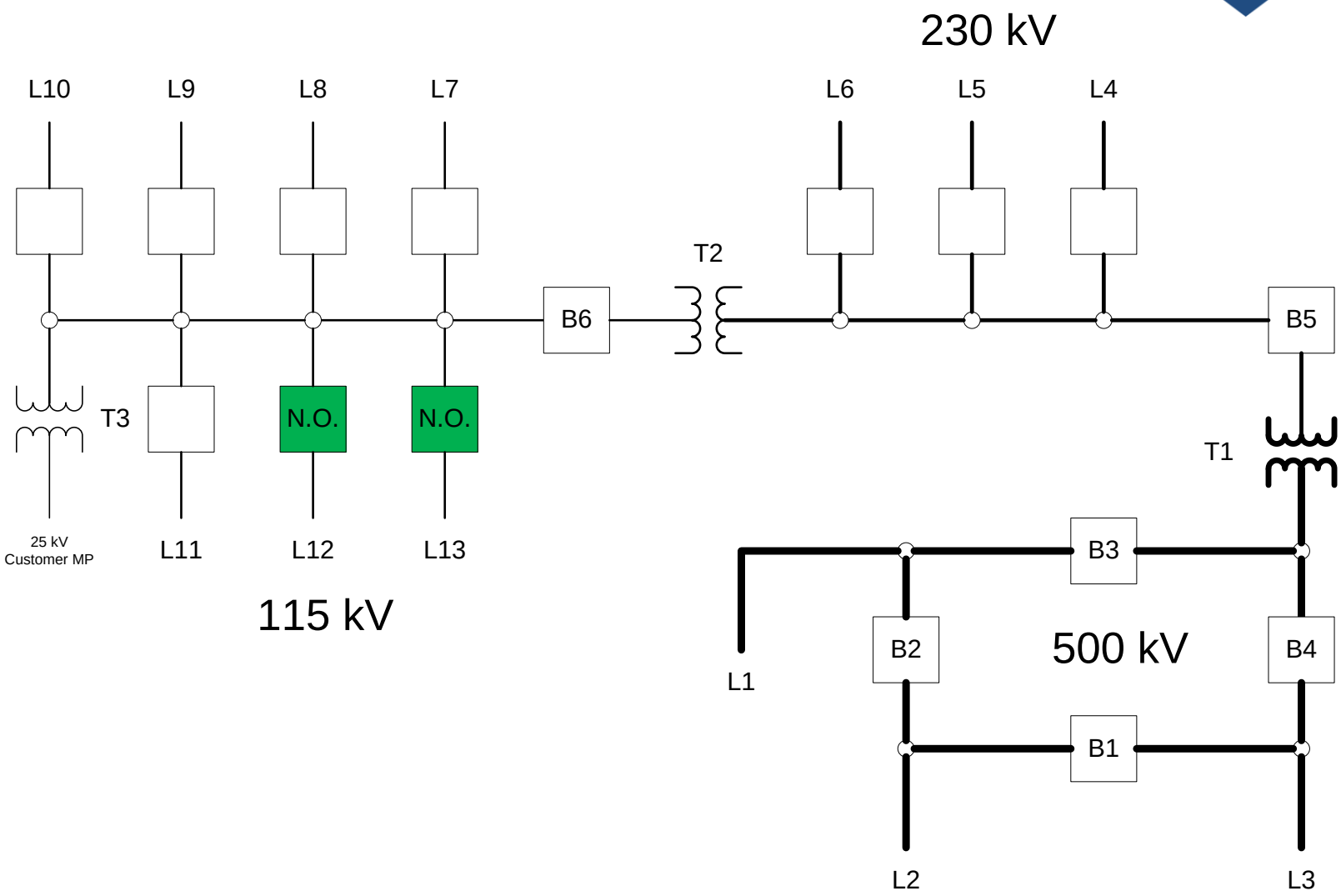
[9] For the purposes of this testing, all bus configurations will be treated as a straight bus (single-breaker) configuration. For example, a fault simulated on a ring bus configuration is modeled as though the fault is on a straight bus, and not on the terminals of any of the elements connected in the ring bus configuration. A fault simulated on a breaker-and-a-half configuration is modeled as though the two buses are a single straight bus.

Table A Change Summary

Table A: Criteria for Buses to be Tested
Buses operated at 200 kV or higher with 4 or more circuits
Buses operated at 100 kV to 200 kV with 6 or more circuits
Buses directly supplying off-site power to a nuclear generating station
Any additional buses the Transmission Planner believes are necessary for the reliable operation of the bulk power system

- Criteria for Buses to be Tested
  - Removed
    - Item related to loss of 300 MW of load
    - Item related to loss of 1,000 MW aggregate generation

Figure 1-2


230 kV
L10
L9
L8
L7
L6
L5
L4
T2
B6
B5
T3
N.O.
N.O.
T1
25 kV
Customer MP
L11
L12
L13
115 kV
B3
B2
500 kV
B4
L1
B1
L2
L3

Example Step 1

- **Example Illustrating Application of the Method**
  - A Transmission Planner identifies that it has 800 buses operated at 100 kV or higher
  - Of these 800 buses, 522 meet the criteria in Table A for "Criteria for Buses to be Evaluated"

Initial Buses			**Step 1**	
115 kV	465		115 kV	240
138 kV	20		138 kV	12
161 kV	15		161 kV	10
230 KV	290		230 KV	250
500 kV	10		500 kV	10
Total	800		Total	522

Step 2

- Each TP will coordinate with each DP, GO, and TO in its transmission planning area to identify:
  - Transformers with through-fault protection that have at least one winding connected at a bus to be tested
  - Any bus from the list developed in step 1, that can be excluded from testing on the basis that the protection system(s) for all Elements connected to the bus and for the physical bus(es), if any, meet the attributes for all categories of components in Table B based on the owner's knowledge of the protection system(s). Each TP will create an initial "List of Buses to be Evaluated" by removing from these bus from the "List of Buses to be Tested"

Table B Change Summary

- Protection System Attributes to be Evaluated
  - Protective Relays
    - Removed “for the element” for clarity
  - Communication Systems
    - Added the phrasing “for communication-aided protection functions (i.e., pilot relaying systems)” for clarity
  - AC Current and Voltage Inputs
    - Added clarifying language about CT installations
  - DC Control Circuitry
    - Added for clarity: “*For the purpose of this data request the DC control circuitry does not include the station DC supply, but does include all the DC circuits used by the protection system to trip a breaker, including any DC distribution panels, fuses, and breakers*.”

Table B

Table B: Protection System Attributes to be Evaluated
Protective Relays: The protection system includes two independent protective relays that are used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.
Communication Systems: The protection system includes two independent communication channels and associated communication equipment when such communication between protective relays for communication-aided protection functions (i.e., pilot relaying systems) is needed to satisfy system performance required in NERC Reliability Standards TPL-002-0b and TPL-003-0a.
AC Current and Voltage Inputs: The protection system includes two independent AC current sources and related inputs, except that separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing can be used to satisfy this requirement; and includes two independent AC voltage sources and related inputs, except that separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device can be used to satisfy this requirement.
DC Control Circuitry: The protection system includes two independent DC control circuits with no common DC control circuitry, auxiliary relays, or circuit breaker trip coils. For the purpose of this data request the DC control circuitry does not include the station DC supply, but does include all the DC circuits used by the protection system to trip a breaker, including any DC distribution panels, fuses, and breakers.

Example Step 2

- **Example Illustrating Application of the Method**
  - After coordinating with its DP, GO, and TO, the TP is able to eliminate 147 buses based on the asset owners' knowledge confirming that the protection systems for the Elements connected to the buses and for the physical bus(es), if any, meet the attributes for all categories of components in Table B

Step 1			**Step 2**	
115 kV	240		115 kV	220
138 kV	12		138 kV	10
161 kV	10		161 kV	8
230 KV	250		230 KV	132
500 kV	10		500 kV	5
Total	522		Total	375

Step 3

- Each TP will simulate a three-phase (3Ø) fault on each bus[12] in its transmission planning area on the "List of Buses to be Evaluated" (step 2). The 3Ø fault is simulated based on the following parameters:
  - Use most recent assessment-stressed system conditions
  - Maximum expected clearing time
    - Trip remote terminals
    - Trip transformers with through fault protection
  - Table C
    - Duration will be long enough to confirm if simulation exhibits one or more adverse impact
    - Evaluate the system response against the criteria

Table C Change Summary

Table C: Performance Measures	
1.	Loss of synchronism of generating units totaling greater than 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections
2.	Loss of synchronism between two portions of the system
3.	Negatively damped oscillations

- Performance Measures
  - Had clarity issues regarding terminology
  - Completely rewritten

Step 4

- Each TP will revise its initial “List of Buses to be Evaluated” developed in step 2, by removing any buses at which the simulated performance in step 3 does not exhibit any of the adverse impacts identified in Table C, “Performance Measures,” and inform each DP, GO, and TO of each of its buses remaining on this intermediate “List of Buses to be Evaluated.”

Example Steps 3 and 4

- **Example Illustrating Application of the Method**
  - The TP simulates a 3Ø fault on each bus in step 3 and identifies that for 215 buses the simulated system performance does not exhibit any of the adverse impacts identified in Table C

Step 3		**Step 4**	
115 kV	220	115 kV	55
138 kV	10	138 kV	5
161 kV	8	161 kV	3
230 KV	132	230 KV	92
500 kV	5	500 kV	5
Total	375	Total	160

Steps 5 and 6

- The DP, GO, and TO will review documentation of its protection system(s) at each bus on the "List of Buses to be Evaluated," developed by the TP in step 4. The DP, GO, and TO will identify and inform the TP of any bus at which the protection system(s) for all Elements connected to the bus and for the physical bus(es), if any, meet the attributes for all categories in Table B, "Protection System Attributes to be Evaluated."
- The TP will revise the "List of Buses to be Evaluated" by removing the buses identified in step 5 at which the protection system(s) for all Elements connected to the bus and for the physical bus(es), if any, meet the attributes for all categories in Table B, "Protection System Attributes to be Evaluated."

Example Steps 5 and 6

- **Example Illustrating Application of the Method**
  - The DP, GO, and TO review protection systems at the buses remaining on the "List of Buses to be Evaluated" and identify that 95 of the buses have at least one Element connected for which the protection does not meet the attributes in Table B

Step 4		**Step 6**	
115 kV	55	115 kV	45
138 kV	5	138 kV	4
161 kV	3	161 kV	2
230 KV	92	230 KV	42
500 kV	5	500 kV	2
Total	160	Total	95

Steps 7, 8, and 9

- The TP will consult with the DP, GO, and TO regarding actual clearing times[13] for all Elements that will trip for a fault on each bus identified on the "List of Buses to be Evaluated" as revised in step 6.
- The TP will simulate a 3Ø fault, on each bus identified on the "List of Buses to be Evaluated" (step 6) in accordance with the method described step 4 with actual clearing time by the DP, GO, and TO.

Steps 7, 8, and 9 Continued

- The TP will update the "List of Buses to be Evaluated" from step 6, removing each bus for which the simulated system performance in step 8 does not exhibit any of the adverse impacts identified in Table C and will inform each DP, GO, and TO of each of its buses on this final "List of Buses to be Evaluated."

Example Steps 7, 8, and 9

- **Example Illustrating Application of the Method**
  - The TP obtains actual clearing times and simulates a 3Ø fault on each bus in step 8 and identifies that 30 buses based on actual clearing times do not exhibit any of the adverse impacts identified in Table C

Step 6		**Step 9**	
115 kV	45	115 kV	28
138 kV	4	138 kV	2
161 kV	2	161 kV	1
230 KV	42	230 KV	32
500 kV	2	500 kV	2
Total	95	Total	65

Step 10

- The DP, GO, and TO assess their protection systems and provide data to the TP:
  - For each bus evaluated in step 9, whether the protection systems meet each of the attributes listed in Table B, “Protection System Attributes to be Evaluated,” for each protection system component category
  - The attributes of the station DC supply listed in Table D, “Station DC Supply Attributes to be Reported,” for each bus that meets the criteria in Table A, “Criteria for Buses to be Evaluated”

[SB1] I think this word is missing.

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Table D Change Summary

Table D: Station DC Supply Attributes to be Reported
The protection system includes two independent station DC supplies
The protection system includes one station DC supply that is centrally monitored; if the station DC supply is a battery the monitoring includes alarms for both low voltage and a battery open condition
The protection system includes one station DC supply that is centrally monitored; the station DC supply is a battery and the monitoring does not include alarms for both low voltage and a battery open condition
The protection system includes one station DC supply that is not centrally monitored

- Station DC Supply Attributes to be Reported
  - Clarifications made to 2 of 4 attributes
    - For a station DC supply that is centrally monitored and is a battery, the monitoring includes alarms for low voltage and battery open
    - For a station DC supply that is centrally monitored and is a battery, the monitoring does not include alarms for low voltage and battery open

Step 11

- The TP will provide the following information in accordance with the data request reporting template.[14]
  - Statistics concerning the buses evaluated
  - Statistics concerning the attributes of the protection system(s) associated with each identified Element
  - Statistics concerning the attributes of the station DC supply at selected buses in each transmission planning area

Template Example

- **Row 1 (Initial Buses)**

115 kV	465
138 kV	20
161 kV	15
230 KV	290
500 kV	10
Total	800

- **Row 2 (Step 1)**

115 kV	240
138 kV	12
161 kV	10
230 KV	250
500 kV	10
Total	522

- **Row 3 (Step 6)**

115 kV	45
138 kV	4
161 kV	2
230 KV	42
500 kV	2
Total	95

- **Row 4 (Step 9)**

115 kV	28
138 kV	2
161 kV	1
230 KV	32
500 kV	2
Total	65

Buses Evaluated						
		≥100 kV - <200 kV	≥200 kV - <300 kV	≥300 kV - <400 kV	≥400 kV - <600 kV	≥ 600 kV
1.	Total number of buses in the transmission planning area:	500	290	0	10	0
2.	Total number of buses in the transmission planning area that meet the criteria in Table A, "Initial Criteria for Buses to be Tested":	262	250	0	10	0
3.	Total number of buses evaluated by the Transmission Planner based on actual clearing times:	51	42	0	2	0
4.	Total number of buses evaluated by the Transmission Planner based on actual clearing times that resulted in system performance exhibiting any adverse impact defined in Table C, "Performance Measures":	31	32	0	2	0
5.	Comments:					

Rationale

- Enhanced to provide more understanding
  - Voltage Thresholds and Facility Selection Criteria
    - Basis for Table A selection criteria
    - Relevance to facilities operated below 100 kV
  - Protection System Components and Attributes
    - Level of detail necessary to:
      - Assess whether a reliability gap exists and, if so
      - Develop appropriate measures tailored to address the concern
  - Performance Measures
    - Revised measures indicative of potential for instability, uncontrolled separation, or cascading outages
  - Simulation Fault Type
    - Assessments based on SLG faults may understate reliability risk
    - Avoid compliance space

Burden on Entities

- Based on the example
  - Transmission Planners

	Estimated time	# of buses	Total time
Step 1	24 h	800	24 h
Step 3	2 h/bus	375	750 h
Step 8	3 h/bus	95	285 h
Step 11	24 h	65	24 h
Total			1083 h

  - DP, GO, and TO (Aggregate in the TP's area)

	Estimated time	# of buses	Total time
Step 2	24 h	800	24 h
Step 3	0.5 h/bus	375	188 h
Step 5	2 h/bus	160	320 h
Step 7	1 h/bus	95	95 h
Step 10	4 h /bus	65	260 h
Total			887 h

Schedule

Period*	Activity
End of 1st month	Transmission Planners must acknowledge the request for data
End of 6th month	Transmission Planners must submit a status report stating percent of work complete
End of 12th month	Transmission Planners must report data for buses operated at 300 kV or higher
End of 18th month	Transmission Planners must report data for buses operated at 200 kV or higher and below 300 kV
End of 24th month	Transmission Planners must report data for buses operated at 100 kV or higher and below 200 kV

***Period** is the first calendar day of the month number following BOT approval, except as noted otherwise.

Posted for Comment

- Informal Comment Period
  - 45-day, ending June 25, 2012
  - Use website for submitting comments
  - Summary consideration of comments
  - Seeking BOT approval in August
- Feedback questions
  - Method, Template, Schedule, and any other items
- If submitting as a group . . .
  - “We support the comments of entity ABC” or
  - “We support the comments of entity ABC, except for…”
  - “We support the comments of entity ABC, and additionally…”

Questions and Answers

- Please submit your questions via the chat feature in ReadyTalk
  - Please reference Step #, Slide # or Data Request Page #
- The presenters will respond to as many questions as possible during remainder of the scheduled webinar

From: Guy V. Zito
To: rsc
Subject: FW: Order 747 Excerpt on RFC Planning Resource Adequacy Analysis, Assessment and Documentation
Date: Thursday, June 28, 2012 10:50:51 AM

RSC Members et al,

During our call to discuss ALR comments last week a lot of concern was expressed by the group in the area of resource adequacy and the potential jurisdictional issues between FERC and the States that could be introduced by the proposed ALR definition that includes reference to this. You might find the below interesting. It appears that with the approval of the RFC "planning" resource adequacy analysis, FERC has carved out a role for NERC which potentially could have some far reaching implications.

Lee please add this to out RSC meeting agenda in Boston.

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From: Mosher, Allen [AMosher@publicpower.org]
Sent: Thursday, June 28, 2012 10:24 AM
To: alrtf_plus
Subject: Order 747 Excerpt on RFC Planning Resource Adequacy Analysis, Assessment and Documentation

Order No. 747 - Final Rule Approving Planning Resource Adequacy Assessment Standard BAL-502-RFC-02

FERC approves regional Reliability Standard, BAL-502-RFC-02 (Planning Resource Adequacy Analysis, Assessment and Documentation), developed by RFC. The Commission also approves four regional reliability definitions related to the approved regional Reliability Standard and the violation risk factors and violation severity levels assigned to the BAL-502-RFC-02 Requirements. *Docket No. RM10-10-000; Order No. 747*

March 17, 2011

http://www.nerc.com/files/Final_Rule_Plan_Resource_Adeq_Assess_3.17.11.pdf

19. With respect to NARUC and the Ohio PUC's arguments that a resource adequacy assessment standard will infringe on areas within a state's jurisdiction, RFC responds that BAL-502-RFC-02 does not encroach on the authority of the states to make the policy decisions that weigh resource adequacy against cost. RFC notes that states within the RFC region are free to use the data and documentation developed under BAL-502-RFC-02 in imposing resource adequacy obligations and making policy decisions regarding what level of service they are willing to pay to achieve. RFC further asserts that each state commission remains the ultimate arbiter of economic decisions regarding how to balance capacity investments against the risk of curtailment as no economic decisions of any kind are mandated by BAL-502-RFC-02. RFC reiterates that the only enforceable mandate under

BAL-502-RFC-02 is the obligation to perform and document the resource adequacy analysis in a consistent way across the RFC region. [20] RFC Reply Comments at 11.

Commission Determination

20. As explained herein, the Reliability Standard before us does not preclude or preempt any action by a state PUC with regard to resource adequacy. As the Commission has previously recognized, resource adequacy raises "complex jurisdictional concerns" which at times are at the "confluence of state-federal jurisdiction."
[21] As the Commission stated in the order in which the Commission certified NERC as the ERO, with respect to FPA section 215(g), "Reliability Reports":[22]

> We agree . . . that the ERO's assessments of Bulk-Power System reliability and adequacy cannot themselves provide the basis for preempting state or regional transmission planning and resource adequacy programs. The Commission can, however, order the ERO to submit adequacy assessments, including recommendations that some entities are found to have inadequate resources. In addition, our regulations provide for a determination of consistency between state actions and a Reliability Standard, as well as an assessment of the Reliability Standard's effectiveness as the Commission may deem appropriate.

[23]
Although the Commission was addressing the interplay between the ERO's role with respect to resource adequacy assessments and states' resource adequacy programs in the context of section 215(g), this interplay is equally relevant to the ERO's role with respect to the development of Reliability Standards because the Commission is acknowledging that FPA section 215 establishes resource adequacy assessments as being relevant to reliability and, further, that the reliability aspect of resource adequacy assessments does not preempt state action.

21. The Commission, by approving BAL-502-RFC-02, is not usurping, intruding on, or preempting any authority exclusively within a state's jurisdiction because, as recognized in Order No. 672, the FPA does not reserve authority for the states over all matters related to or that flow from "resource adequacy." Moreover, the "savings" provision in section 215, section 215(i)(3), is clear that nothing in section 215 shall be "construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such [State] action is not inconsistent with any reliability standard." As we have clarified in a prior order, the saving provision in section 215(i) is not a grant of new authority to the states, but merely preserves any authority states may have under state law "to take action to ensure the safety, adequacy, and reliability of electric service within that State, so long as such action is not inconsistent with any reliability standard . . . ."[24] Thus, we do not agree with NARUC or the Ohio PUC that the approval of BAL-502-RFC-02 will impinge on states' jurisdiction over matters related to resource adequacy. BAL-502-RFC-02 does

not touch the establishment of specific resource adequacy requirements, and thus does not intrude on the state's decisional authority with respect to building or acquisition of assets or capacity to meet resource adequacy needs.

22. With respect to the Ohio PUC's argument that by approving a regional Reliability Standard mandating the use of a specific resource adequacy planning criterion (the one day in ten years criterion), the Commission is establishing that criterion as the *de facto*

[24] *New York State Reliability Council,* 122 FERC ¶ 61,153, at P 33 (2008) (emphasis added).Docket No. RM10-10-000 - 16 -

criterion to be used to set resource investment requirements, this argument appears to be borne out of the Ohio PUC's concern regarding preserving its authority to set resource adequacy standards. The standard does not impinge on Ohio PUC's authority to set or determine how to meet resource adequacy standards. Contrary to the Ohio PUC's concerns, the Commission believes that establishing a common criterion for resource planning will provide states with a uniform framework of information regarding resource adequacy. The information the reliability assessments provide would then be available to the states to use or could serve as a platform on which to layer additional factors, such as costs, as the states see fit.

23. The Commission also finds that the proposed resource adequacy analyses and documentation requirements in BAL-502-RFC-02 fall within the definition of "Reliability Standard" as that term is defined in section 215(a)(3) and pertain to the "Reliable Operation" of the Bulk-Power System as that term is defined in section 215(a)(4). Under section 215(a)(3), the only type of requirement that is explicitly precluded from being part of an enforceable Reliability Standard is a "requirement to enlarge [bulk-power system facilities] or to construct new transmission capacity or generation capacity."[25] BAL-502-RFC-02 does not include any such requirement. Specifically, BAL-502-RFC-02 mandates planning, it does not require entities to secure any resources as an outcome of the resource adequacy assessment.

[25] 16 U.S.C. 824o(a)(3). Docket No. RM10-10-000 - 17 -

24. BAL-502-RFC-02 also falls within the definition of Reliability Standard, as it provides for the *reliable operation* of the Bulk-Power System because it serves to identify potential resource adequacy deficiencies in a planning horizon with time to mitigate projected resource adequacy problems before shortages of resources occur in the operating horizon. Shortages of resources in the operating horizon can lead to blackouts and even cascading outages. Under these conditions, operators may be continually challenged to balance load with energy to prevent major power or voltage swings across the grid that can lead to blackouts and cascading outages. Because the standard does not prescribe that action must be taken, entities with authority for planning and siting new resources, including demand response resources or any other

resource type, can determine the appropriate course of action, if any, that should be taken, including performing additional resource adequacy studies. The standard therefore does not preclude or preempt any action by a state commission with regard to resource adequacy. The Ohio PUC argues that NERC and RFC "conflate[] resource adequacy with reliable operation of the Bulk-Power System," stating that the definition of "Reliable Operation" cannot be enlarged and manipulated to include planning to build such capacity.[26] The Commission finds that the Ohio PUC, in making this argument, is reading into BAL-502-RFC-02 a requirement that registered entities within RFC build or acquire new generating capacity. Such a requirement simply does not exist in BAL-502-RFC-02.

[26] Ohio PUC Comments at 5-6. Docket No. RM10-10-000 - 18 -

25. Ohio PUC further argues that a lack of adequate resources to serve firm load does not lead to "instability, uncontrolled separation or cascading failures," which are hallmarks of the term "Reliable Operation." We disagree with the Ohio PUC's interpretation of the definition of "Reliable Operation" as stated in section 215. A more careful reading reveals that the "hallmarks" of this term, instability, uncontrolled separation or cascading failures, are not to occur upon the unanticipated failure of a system element. If resources cannot meet load, or are insufficient to provide a reserve margin above expected load, then instability, uncontrolled separation or cascading failures can result from the unanticipated loss of a system element. If this situation occurs, reliable operation is not achieved due to resource inadequacy. Thus, like other planning standards, BAL-502-RFC-02 provides for the reliable operation of the Bulk-Power System as it will help identify areas of concern that, if left unresolved, could result in future instability, uncontrolled separation, or cascading failures of the Bulk-Power System.

26. The only other affirmative limitation on the scope of Commission-approved and enforceable Reliability Standards under FPA section 215 is the savings clause in section 215(i)(2), which states: "This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services."[27] Regional Reliability Standard BAL-502-RFC-02 does not set any resource

[27] 16 U.S.C. 824o(i)(2). Docket No. RM10-10-000 - 19 -

adequacy standards. Specifically, BAL-502-RFC-02 does not impose on any registered entity a resource adequacy obligation because the standard contains no requirement for an entity to construct or otherwise invest in additional transmission, distribution, or generation resources or capacity. Nothing in BAL-502-RFC-02 requires any entity to use or take any action with respect to the resulting resource adequacy assessment. Regional Reliability Standard BAL-502-RFC-02 only requires a resource adequacy analysis and documentation of such analysis. Importantly, the Commission is not,

through BAL-502-RFC-02, setting, enforcing or in any way mandating the resource adequacy levels that are derived through the BAL-502-RFC-02 resource adequacy analyses. Accordingly, BAL-502-RFC-02 does not run afoul of the prohibitions in FPA sections 215(a)(3) or 215(i)(2).

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From: Willie Phillips [mailto:Willie.Phillips@nerc.net]
Sent: Thursday, June 28, 2012 9:11 AM
To: alrtf_plus
Subject: FW: FERC ALR Directive Summary

FYI.

From: Willie Phillips
Sent: Thursday, June 28, 2012 8:26 AM
To: Herb Schrayshuen
Cc: Mallory Huggins
Subject: FERC ALR Directive Summary

Herb,

As we discussed, the following is a brief summary of the early FERC orders that address "adequate level of reliability."

FERC directed NERC to consider and propose methods for ensuring Reliability Standards provide for an adequate level of reliability and for defining "an adequate level of reliability" in its "Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing" 116 FERC ¶ 61,062, at P 240 (July 20, 2006):

> 240. Although NERC's Rules of Procedure call for a specific performance requirement not resulting in a lowest common denominator compromise, a proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called "lowest common denominator"—if such practice does not adequately protect Bulk-Power System reliability.[1] We agree with Alcoa that, unless NERC further explores what it means to provide an adequate level of reliability, targeting a valuable reliability goal may not be enough to prevent a Reliability Standard from reflecting the lowest common denominator. We are

concerned that some process participants may support only those Reliability Standards that validate their current practices. However, we disagree with Alcoa that it is necessary to specify in advance a type of cost-benefit analysis for the ERO to apply uniformly to all Reliability Standards under development. Indeed, it is sufficient to understand that, while a Reliability Standard need not reflect the optimal method, or best practice, for achieving its reliability goal with regard to implementation cost, it should achieve its reliability goal effectively and efficiently.[2] Therefore, we direct NERC to consider and propose methods for ensuring that Reliability Standards provide for an adequate level of reliability and defining "an adequate level of reliability." For example, NERC should address the possibility that the super-majority voting requirement could, in some cases, allow a small portion of the industry to veto a standard that is designed to improve reliability or otherwise remedy flaws in an existing standard. Although we believe that a super-majority requirement is generally consistent with the nature of the ERO as a self-regulatory organization, we are concerned that, in certain instances, it could pose an obstacle to strengthening the reliability of the grid as envisioned by Congress in enacting section 215. NERC should address this possibility in its compliance filing.

FERC also addressed the ALR directive in its January 18, 2007 Order on Compliance Filing, 118 FERC ¶ 61,030 (2007), at P 16:

16. On the issue of defining an adequate level of reliability, the Commission accepts the ERO's proposal to establish a stakeholder process to achieve this important goal. While Alcoa is correct that NERC's proposal defers the definition of adequate reliability, NERC's stakeholder process provides a ready means to fairly define adequate reliability and at the same time provide stakeholders with input to the process. Moreover, the technical details and development of metrics that will be required to complete the complex task of defining an adequate level of reliability will necessarily take some time. Even so, we agree with Alcoa that the initiation of this process should not be deferred and must proceed on a set schedule. The ERO must address the issue of whether an adequate level of reliability can be defined to partly or wholly apply to all Reliability Standards, whether it can be defined for certain sets of Reliability Standards (BAL, FAC etc.), or whether, in some instances, it must be tailored to each individual Reliability Standard. The ERO must consider opportunities to develop and apply metrics that can form the basis for broadly defining an adequate level of reliability, such as the creation of a precisely defined set of system operating states.[3] NERC should explore this and other possibilities and continue to develop metrics that will help determine compliance with Reliability Standards and better measure whether compliance with Reliability Standards

> assures an adequate level of reliability. We therefore direct the ERO to develop a work plan to propose a continuing improvement process to consider "adequate level of reliability" when developing new or modified Reliability Standards. If the Commission decides in the Final Rule to require NERC to submit a workplan as proposed in the Reliability Standards NOPR, it would be appropriate to include NERC's plan for considering "adequate level of reliability" with the workplan proposed by the Commission in the *Reliability Standards NOPR*.

On May 5, 2008, NERC submitted to FERC, solely as an informational filing, the definition of ALR that the NERC BOT approved on February 12, 2008. In that filing, NERC noted the ongoing stakeholder process to develop metrics for ALR:

> As directed by the Commission in its January 18, 2007 Order on Compliance Filing (118 FERC ¶ 61,030 (2007), P 16), NERC is also working with industry stakeholders to develop and apply metrics for identifying and tracking key reliability indicators, including general metrics for the characteristics of "adequate level of reliability." This will enable NERC to benchmark reliability performance and measure reliability improvements that result from its other programs.

In the filing letter for the May 5, 2008 ALR definition David Cook noted:

> NERC does not expect to use the definition to determine whether an individual reliability standard being developed through the NERC standards development process meets the requirements for reliability standards stated in section 215 of the Federal Power Act and the Commission's regulations and orders. In short, NERC will use the definition as a guide to whether or not the standards, taken as a whole, promote "an adequate level of reliability."

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[1] *Id.* at P 329.

[2] *Id.* at P 328.

[3] *See*, *e.g. Mandatory Reliability Standards for the Bulk-Power System*, Notice of Proposed Rulemaking, FERC Stats. & Regs., Vol. IV, Proposed Regulations, ¶ 32,608 at 32,911 – 33,097 at P 275 (2006) (*Reliability Standards NOPR*).

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Consideration of Comments

Cost Effective Analysis Process

The Cost Effective Analysis Process (CEAP) team thanks all commenters who submitted comments on the draft CEAP. These comment questions were posted for a 60-day public comment period from May 7, 2012 through July 6, 2012. Stakeholders were asked to provide feedback through a special electronic comment form. There were 45 sets of comments, including comments from approximately 141 different people from approximately 103 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Cost_Effective_Analysis_Process.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

1. Do you agree there should be a formal process to determine the cost of developing reliability standards? If you disagree, please explain why. 11

2. Do you agree with the approach in the proposed NERC Cost Effective Analysis Process (CEAP)? If you disagree, please explain your concerns and provide specific suggestions for addressing the concerns. 24

3. The NERC CEAP incorporates two separate phases of reviews: • The first phase is the Cost Impact Analysis (CIA) which is intended to be an assessment to determine the relative cost impacts of a particular proposed course of action. This is not intended to be a comprehensive cost benefit analysis but rather to identify potential cost magnitude and achievement of ALR and risk mitigation benefits • The second phase is the Cost Effectiveness Assessment (CEA) which may be considered a more detailed assessment whose purpose is to provide information about the relative effectiveness and cost impacts of different approaches to eliminating disparities, increasing life expectancy or of any program or initiative and to provide the industry to offer more cost efficient alternatives to achieve the same reliability objective of the standard. Do you agree with the 'two separate phases'? If you disagree, please provide suggested changes. 41

4. Appendix B is comprised of standard survey questions for Phase One and Phase Two. Additional questions may be added as appropriate. Do you agree with the survey questions in Appendix B? If you disagree, please suggest questions. 51

5. Do you have any other comments or suggestions to improve the proposed CEAP? 65

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Ron Sporseen	PNGC Comment Group	X		X	X				X		

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe Jarvis	Blachly-Lane Electric Cooperative	WECC	3
2.	Dave Markham	Central Electric Cooperative	WECC	3
3.	Dave Hagen	Clearwater Power Company	WECC	3
4.	Roman Gillen	Consumers Power Inc.	WECC	1, 3
5.	Roger Meader	Coos-Curry Electric Cooperative	WECC	3
6.	Bryan Case	Fall River Electric Cooperative	WECC	3
7.	Rick Crinklaw	Lane Electric Cooperative	WECC	3
8.	Annie Terracciano	Northern Lights Inc.	WECC	3
9.	Aleka Scott	PNGC Power	WECC	4

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10.	Heber Carpenter	Raft River Rural Electric Cooperative	WECC	3
11.	Steve Eldrige	Umatilla Electric Cooperative	WECC	1, 3
12.	Marc Farmer	West Oregon Electric Cooperative	WECC	4
13.	Margaret Ryan	PNGC Power	WECC	8
14.	Rick Paschall	PNGC Power	WECC	3

2.	Group	John A. Anderson	ELCON and Occidental Energy Ventures							X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michelle D'Antuono	Occidental Energy Ventures		7

3.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Group	Chris Higgins	Bonneville Power Administration	X		X	X		X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Hardev	Juj	WECC	1
2.	Don	Watkins	WECC	1
3.	Fran	Halpin	WECC	5
4.	Rita	Coppernoll	WECC	1
5.	Kristy	Humphrey	WECC	1
6.	Meg	Albright	WECC	1
7.	Mike	Miller	WECC	1
8.	Erika	Doot	WECC	3, 5, 6
9.	Mary	Willey	WECC	1

5.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Stephen McGie	City of Coffeyville	SPP	NA
2.	Fred Meyer	Empire District Electric	SPP	1
3.	Valerie Pinamonti	AEP	SPP	1, 3, 5

6.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		RFC	5, 6
2.	Randi Heise		MRO	5, 6
3.	Connie Lowe		NPCC	5, 6
4.	Michael Crowley		SERC	1, 3, 5, 6

7.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

		Operator		
3.	Greg Campoli	New York Independent System Operator	NPCC	1
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

8.	Group	Terry Bilke	ISOs' Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al DiCaprio	PJM		2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Charles Yeung	SPP		2
3.	Kathleen Goodman	ISONE		2
4.	Ben Li	IESO		2
5.	Don Weaver	NBISO		2
6.	Steve Meyers	ERCOT		2
7.	Gary DeShazo	CAISO		2

9.	Group	Joel deJesus	G&T Cooperatives										

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Bussman	Associated Electric Cooperative, Inc.	SERC	1, 3, 5, 6
2.	Dan Klempel	Basin Electric Cooperative	MRO	1, 3, 5
3.	Luis Zaragosa	Tri-State Generation and Transmission Association Inc.	WECC	1, 3, 5

10.	Group	Pat Huntley	SERC Standards Committee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neil Phinney	Georgia System Operations Corp.	SERC	1
2.	Edwin Goff	Progress Energy Carolinas	SERC	1
3.	Russ Schussler	Georgia Transmission Corporation	SERC	1
4.	Gerry Beckerle	Ameren	SERC	1
5.	Jim Case	Entergy	SERC	1
6.	Don Reichenbach	Duke Energy Carolinas	SERC	1
7.	John Sullivan	Ameren	SERC	1
8.	Scott Miller	Municipal Electric Authority of Georgia	SERC	1
9.	John Troha	SERC Reliability Corp.	SERC	NA

11.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates										
				X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
2.			WECC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	Brent Ingebrigtson	LG&E and KU Services Company	SERC 1, 3, 5, 6										
12.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				
	Additional Member	**Additional Organization**	**Region** **Segment Selection**										
1.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT 1, 5										
2.	Megan Wagner	Sunflower Electric Power Corporation	SPP 1										
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC 1, 3, 4, 5										
13.	Individual	Emily Pennel	Southwest Power Pool Regional Entity										X
14.	Individual	JANET SMITH	ARIZONA PUBLIC SERVICE COMPANY	X		X		X	X				
15.	Individual	Diane Barney, Chair - Electric Reliability Staff Subcommittee	National Association of Regulatory Utility Commissioners (NARUC)									X	
16.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
17.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
18.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
19.	Individual	Barry Lawson	National Rural Electric Cooperative Association (NRECA)			X	X						
20.	Individual	Dan Roethemeyer	Dynegy					X					
21.	Individual	Larry Rodriguez	Entegra Power Group LLC					X	X				
22.	Individual	Steve Alexanderson P.E.	Central Lincoln			X	X					X	

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
24.	Individual	Steven Powell	Trans Bay Cable, LLC	X									
25.	Individual	Thomas Gianneschi	Alcoa, Inc.							X			
26.	Individual	Michael Shaw	LCRA Transmission Services Corporation	X									
27.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
28.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
29.	Individual	Kirit Shah	Ameren	X		X		X	X				
30.	Individual	Ed Davis	Entergy Services	X		X		X	X				
31.	Individual	Brian J Murphy	NextEra Energy Inc	X		X		X	X				
32.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
33.	Individual	Daniel Duff	Liberty Electric Power					X					
34.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
35.	Individual	Patrick Brown	Essential Power, LLC					X					
36.	Individual	John Pearson	ISO New England		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Maggy Powell	Exelon Corporation	X		X		X	X				
38.	Individual	Edwin D. Croft	Puget Sound Energy, Inc.	X		X							
39.	Individual	John P. Hughes	Electricity Consumers Resource Council (ELCON)	X		X		X	X	X			
40.	Individual	Rebecca Moore Darrah	MISO		X								
41.	Individual	New England States Committee on Electricity	New England States Committee on Electricity										
42.	Individual	Massachusetts Department of Public Utilities	Massachusetts Department of Public Utilities									X	
43.	Individual	Nathan Mitchell	American Public Power Association			X							
44.	Individual	Douglas Webb	KCP&L	X		X		X	X				
45.		Janet Smith	APS										

1. **Do you agree there should be a formal process to determine the cost of developing reliability standards? If you disagree, please explain why.**

Summary Consideration:

Organization	Yes or No	Question 1 Comment
PNGC Comment Group	Yes	Absolutely agree. As representatives of small rural cooperatives we especially hope you'll consider that even relatively modest costs for larger entities can be overly burdensome for small utilities.
Response:		
ELCON and Occidental Energy Ventures	Yes	Comments: Occidental Energy Ventures Corp. (OEVC) and the Electricity Consumers Resource Council (ELCON) (herein: Industrial Consumers), the Sector 8 representatives of large end-use electricity consumers on the MRC, agree that cost/benefit analysis of a proposed standards development effort is a critical part of sensible regulation. If properly performed, the efforts with the highest return on reliability can be addressed as a top priority - with some measurable economic justification behind them. For the most part, the cost of NERC compliance must be absorbed by large industrials required to be compliant with NERC Standards. If those costs become too high - and there are no means to prove that they are serving a vital purpose - many will choose not to sell excess energy capacity to the BES. In our view, the threat of over-regulation is in of itself a reliability risk.Along the same lines, public utilities must also be able to justify their costs to local Public Utility Commissions. Even if they are able to pass on their costs to consumers, this presents a societal risk - as rising electric costs affect the poorest segments of the population the most.

Organization	Yes or No	Question 1 Comment
Response:		
MRO NSRF	Yes	Please note that the question should ask; Do you agree there should be a formal process to determine the cost of Implementing (to include maintenance and ongoing compliance resource requirements) reliability standards? This change comes directly from the second sentence of the CEAP Executive Summary. Cost is a key component in reasonably assuring that we have and maintain a reliable system (cost vs. benefit).
Response:		
Bonneville Power Administration	Yes	
SPP Standards Review Group	Yes	We concur with the inclusion of a process to consider the costs of implementing reliability standards. Some standards have a greater impact on the reliability of the BES than others and factoring in the costs of standards is one way that the industry can get the most bang for its buck. We can build an electric system that is very reliable and secure but would we be able to afford one that provides service 100% of the time; probably not, nor would our customers agree to incur the cost of such a system. Incorporating cost considerations provides a way to more effectively reach a balance.
Response:		
Dominion	Yes	
Northeast Power Coordinating Council	Yes	The costs associated with implementation, maintenance, and on-going compliance as well as the incremental reliability impact need to be considered as part of the reliability standards development process. The CEAP should only come into play for a standard proposed in response to a government request when the existing standard requires updates.There is concern with balancing the operation and planning the electric system in accordance with existing standards with the workload of having to actively participate in the development of new standards. It

Organization	Yes or No	Question 1 Comment
		may not be possible to provide input for cost estimates, and until a standard is actually in use it may be impossible to fully realize the cost impact and effectiveness. It should be noted that this is not a mandatory effort and that in some cases cost input may not be provided because of other priorities. While it is understood that extrapolation of data will occur in cases where data is not provided there is concern over resource balance and the importance of providing cost input.
Response:		
ISOs' Standards Review Committee	Yes	
G&T Cooperatives	Yes	Associated Electric Cooperative, Inc. ("Associated Electric"), Basin Electric Power Cooperative ("Basin Electric"), and Tri-State Generation and Transmission Association, Inc. ("Tri-State") (collectively, the "G&T Cooperatives") jointly submit these comments in support of NERC's development of a formal process for assessing costs of developing and implementing reliability standards. (1) Although cost considerations are implicitly addressed in voting by individual members of the ballot body, the lack of a formal process has contributed to a proliferation of standard requirements whose administrative costs appear to outweigh their benefit to reliability. In fact, among the most violated Reliability Standards are requirements that are largely administrative and procedural in nature, such as CIP-004 (providing for employee training, cyber security awareness, background checks, and procedures governing access authorizations) and CIP-001 (maintenance of procedures for identifying and reporting sabotage events, and associated training). Even many of the violations of the protection system maintenance and testing requirements under PRC-005 relate to documentation issues concerning failure to retain evidence that maintenance and testing has occurred. The G&T Cooperatives therefore strongly support the incorporation of a cost effectiveness analysis as a routine part of the standard development process. (2) One

Organization	Yes or No	Question 1 Comment
		of the key drivers for the results-based standards initiative in 2010 was the need to focus the standards development process on standards expected to lead to the greatest increase in reliability, while converting "non-essential" requirements/standards to guidelines. See Results Based Standards Webinar: http://www.nerc.com/filez/webinars/rbstds102010/lib/playback.html. This goal can best be achieved through a formal process to assess the benefits and the costs of new standards under development. Accordingly, the implementation of a cost effectiveness analysis process (CEAP) is critical to NERC's long term initiative to move to results-based standards. (3) FERC appears open to the idea of establishing a cost effectiveness analysis process. FERC noted early on in Order No. 672 that: "The proposed Reliability Standard does not necessarily have to reflect the optimal method, or 'best practice,' for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently." Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, Order No. 672, FERC Stats. & Regs. Â¶ 31,204 at P. 328 (2006). More recently, Commissioner Norris made remarks that underscored the need for the explicit assessment of the costs and benefits of standards as they are being developed: "As I have thought about this issue, it has become clear to me that in any discussion of a new or revised mandatory reliability standard, there is always a tradeoff between the level of reliability to be achieved by that standard and the costs that the standard will impose. However, that tradeoff is rarely discussed explicitly in the standards development process or during the Commission's review of standards. But, we know that it is an implicit consideration of entities participating in the standards development process. I believe it is more appropriate to make those considerations,

Organization	Yes or No	Question 1 Comment
		where they are relevant, explicit. Therefore, I have advocated for an open dialogue between NERC, the industry, and the Commission to consider the connection between the mandatory standards we approve to maintain and improve the reliability of the Bulk Power System and the costs required to meet those standards." Transmission Planning Reliability Standards, 139 FERC Â¶ 61,060 (2012). (4) While the G&T Cooperatives submit constructive criticism in the responses to the remaining questions on specific aspects of the CEAP, they strongly support the idea conceptually. The constructive criticism is offered to assist NERC in ensuring that the CEAP can function appropriately and identify the costs and benefits of new standards accurately.
Response:		
SERC Standards Committee	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	(1) We feel this is a great starting point for considering costs in the development of reliability standards and we thank NERC for the opportunity to provide input.
Response:		
Southwest Power Pool Regional Entity	Yes	We agree there should be a formal process for determining costs/benefits. However, as stated in the CEAP document, the costs aren't for "developing" the standard but for "implementation, maintenance, and ongoing compliance."
Response:		
ARIZONA PUBLIC SERVICE COMPANY	Yes	
National Association of Regulatory Utility Commissioners (NARUC)	Yes	NERC should be applauded for initiating this long overdue effort. States routinely make decisions related to the local distribution system and generation that weigh benefits of a project against ratepayer impacts. Bulk system standards are the only area where cost and benefits are not

Organization	Yes or No	Question 1 Comment
		currently considered. Hundreds of millions to billions of dollars of investment can be caused by standards development. While states put a very high premium on reliability, it is not reasonable to attain it at any cost. Some measurement must be developed to provide decision makers input on the cost and benefits of their actions.
Response:		
PacifiCorp	Yes	PacifiCorp supports the development of a formal process as identified by this project. However, PacifiCorp cautions that the costs of developing and implementing reliability standards may be very difficult to quantify and, if compared against an amorphous benefit, cost determinations may become somewhat meaningless as a tool for NERC or registered entities.
Response:		
Salt River Project	Yes	
Southern Company	No	Instead of having a a separate formalized process to determine the cost of developing reliability standards, we believe that the cost of developing new reliability standards (along with other criteria) should be included as a part of the Standard Development Process.
Response:		
National Rural Electric Cooperative Association (NRECA)	Yes	NRECA supports the development of a cost impact provision to be included in the standards development process. Creating such a provision will be challenging and will take some time to complete. NRECA is committed to working with NERC, the REs and stakeholders to develop a cost impact provision. NRECA agrees with the language in the draft CEAP that the cost impacts that need to be evaluated are those related to standard implementation, compliance maintenance and ongoing compliance resource requirements. However, NRECA believes that the CEAP should not look only at industry-wide impacts/cost, but

Organization	Yes or No	Question 1 Comment
		should also ensure that there are not disproportionate impacts on any class of registered entities - including small entities -- in order to adhere to the "not unduly discriminatory" provision of Section 215 of the Federal Power Act.While NRECA is supportive of this initiative and believes it is appropriate for the CEAP to rely on stakeholder input, we are also concerned that this could run counter to the current efforts to make the standards development process more efficient and effective by adding more assignments to the SDTs. Please provide an explanation of how the CEAP will impact the speed and volume of the SDT's work responsibilities. The CEAP documents that were provided for review indicated that this was an initial step or first phase of development of a cost impact provision. Please provide an explanation of any future plans/phases of this initiative so that we can better understand the needs of this initial phase and the potential future direction of this initiative.
Response:		
Dynegy	Yes	I like the concept and feel it is a step in the right direction of something that needs to be considered in Standards.
Response:		
Entegra Power Group LLC	Yes	
Central Lincoln	Yes	It is about time that compliance cost is factored in. For too long we have been proceeding in the reliability/compliance at any cost mode. Thank you for beginning to look at costs.
Response:		
Cowlitz County PUD	Yes	Not only should the cost of travel, room and board, and salaries required of the Standard Drafting Team and support personnel be considered, but also of the expected observers who actively participate with valuable input to the SDT.

Organization	Yes or No	Question 1 Comment
Response:		
Trans Bay Cable, LLC	Yes	
Alcoa, Inc.	Yes	
LCRA Transmission Services Corporation	Yes	We agree that costs associated with implementation, maintenance, and on-going compliance as well as the incremental reliability impact need to be considered as part of the reliability standards development process.
Response:		
American Transmission Company, LLC	Yes	
Hydro-Quebec TransEnergie	Yes	Hydro Quebec TransÃ‰nergie agree, but we think that cost effectiveness may be even more important than cost impact. That is to say phase 2 of the CEAP is more important.
Response:		
Ameren	Yes	
Entergy Services	Yes	
NextEra Energy Inc	Yes	NextEra Energy, Inc. (NextEra) is supportive a formal process to determine the cost effectiveness Reliability Standards. The process itself should be as efficient as possible, thus not unnecessarily imposing new burdens on Registered Entities, and include consideration of potentially more efficient options for a given reliability need.
Response:		
Public Service Enterprise Group	No	We believe you mean the “to determine the cost of “IMPLEMENTING reliability standards” not “developing reliability standards.” As modified, we agree.
Response:		
Liberty Electric Power	Yes	

Organization	Yes or No	Question 1 Comment
City of Austin dba Austin Energy	Yes	
Essential Power, LLC	Yes	
ISO New England	Yes	Though we agree with the formal process of determining cost, there is some concern with balancing the workload of planning and operating the electric system in accordance with existing standards along with the workload actively participating in the development of new standards. In some cases it may not be possible to provide input for the cost estimates and until a standard is actually in use it may be impossible to fully realize the cost impact. It should be noted that this is not a mandatory effort and that in some cases cost input may not be provided due to other priorities. While it is understood that extrapolation of data will occur in cases where data is not provided there is still some concern over resource balance and the importance of providing cost input.
Response:		
Exelon Corporation	Yes	
Puget Sound Energy, Inc.	Yes	
Electricity Consumers Resource Council (ELCON)	Yes	
MISO	Yes	The relative costs and benefits of a proposed reliability standard are two of the most important considerations in determining whether such a proposal should be adopted, rejected, or modified. Cost-benefit considerations should be utilized during both the development and enforcement of mandatory reliability standards; however, such considerations tend not to be clearly articulated or defined and, even when defined, are not given adequate, meaningful assessment. As a result, many standards and requirements that have been approved and are effective for compliance purposes do not provide significant benefits to reliability despite requiring considerable resource expenditures by Registered Entities. Having a formalized process for determining costs

Organization	Yes or No	Question 1 Comment
		and benefits and meaningfully evaluating these prior to standard development and/or approval would clarify for the industry, NERC, and Regional Entities the considerations and analyses that are appropriate for determining high value/benefit reliability standards and result in the development, revision, or interpretation of the reliability standards that provide the most benefit to reliability Accordingly, MISO agrees that there should be a formal cost determination as part of the process of developing reliability standards.
Response:		
New England States Committee on Electricity	Yes	The New England States Committee on Electricity (NESCOE) strongly supports NERC's effort to identify and evaluate cost impacts as part of the process of developing reliability standards. NESCOE is New England's Regional State Committee and is governed by a Board appointed by the six New England Governors. These comments reflect the collective view of the six New England states. NERC's Costs Effective Analysis Process (CEAP) largely tracks a Northeast Power Coordinating Council (NPCC) process implemented last year to integrate cost effectiveness into its standards development procedures. Last year, NESCOE expressed its support for NPCC's leadership in this critical area. At the same time, NESCOE communicated concerns to NERC in a September 2011 letter regarding the absence of a cost-benefit analysis as part of NERC's reliability standards development process. We appreciate NERC's responsiveness to concerns expressed by NESCOE and others, and we look forward to working with NERC to develop its process for considering costs. The New England states strive to ensure that the appropriate level of infrastructure is in place to achieve a robust and reliable bulk electric system. However, as NERC recognizes here, incremental reliability gains cannot be considered in a vacuum, separate from an understanding of the magnitude of risk and cost associated with federal reliability standards. NERC's concurrent consideration of costs,

Organization	Yes or No	Question 1 Comment
		reliability risks and benefits-as captured in the proposed CEAP-should help tailor the most appropriate and cost effective approach to achieving a reliability objective.
Response:		
Massachusetts Department of Public Utilities	Yes	The Massachusetts Department of Public Utilities ("Mass DPU") appreciates the opportunity to comment on NERC's draft Costs Effective Analysis Process ("CEAP"). The Commonwealth of Massachusetts is the largest state by population and load in New England. It comprises 46% of both the region's population and electricity consumption. Generating plants located in Massachusetts represent 41% of New England's capacity and our capital city, Boston, is the largest load center in the region.The Mass DPU strongly supports NERC's implementation of the CEAP, which incorporates cost effectiveness into the standards development process. Our comments closely mirror those filed today by our regional state committee, the New England States Committee on Electricity ("NESCOE"). We worked closely with NESCOE to develop its comments, and we file separately here as a voting member of NERC to underscore their importance to us.The Mass DPU, along with its fellow New England states, strives to ensure that the appropriate level of infrastructure is in place to achieve a robust and reliable bulk electric system. However, as NERC recognizes here, incremental reliability gains cannot be considered in a vacuum, separate from an understanding of the magnitude of risk and cost associated with federal reliability standards. NERC's concurrent consideration of costs, reliability risks and benefits-as captured in the proposed CEAP-should help tailor the most appropriate and cost effective approach to achieving a reliability objective.
Response:		
American Public Power Association	Yes	

Organization	Yes or No	Question 1 Comment
KCP&L	Yes	1.We agree a formal process to determine the costs of developing reliability standards is appropriate and has benefits; although, even with the process running in tandem with the reliability standard drafting process, there is concern of introducing complexity, as well as impeding and extending the drafting process by adding further elements and additional steps to the drafting process. We strongly disagree that the proposed Cost Effectiveness Analysis Process (CEAP) concept at a 50,000-foot level provides a simple mechanism for development of costs. 2. As NERC Staff compile the Cost Impact Analyses (CIA), the global nature of stakeholders across Regional Transmission Organizations (RTO) and within the RTOs makes it difficult to normalize the cost analysis at this early point in the drafting process. Recognizing NERC Staff will consider regional reliability impacts, this is not until Phase II is completed (Step 4) and we submit there is benefit earlier in the process to consider regional impacts. For example: the cost impact of a change in the vegetation requirements is different between urban and rural systems or, by further example, desert versus wooded locals. This illustrates normalization of costs, even at a high level, to be potentially complex. 3. Additionally, the spectrum of system design among NERC members adds further questions of how to normalize the high level view of costs. For example: the age, maintenance priorities, and system design is distinctive for each footprint. The determination of cost of implementing new requirements is unique to each system and, as proposed under the CEAP process, requires the relevant stakeholder to provide that information, which could be challenging without a fully vetted requirement and potentially burdensome. In the initial phase, there is little discussion of how normalization between regions will be captured. 4. Finally, the posting of the Phase I CIA outcome could incent companies that disagree with the cost analysis to raise further objection in the Standard Development Process, which is burdensome. In the end, disagreement over the CIA could very well create situations that bog the

Organization	Yes or No	Question 1 Comment
		comment process down as stakeholders duel over the CIA assumptions and conclusions. These situations raise the question of what will the weight of CIAs be against a proposed requirement? On the other hand, if a high cost for a marginal return on reliability, or better stated, if the cost does not materially mitigate risk, isn't that the purpose of the CEAP--attempting to preempt further development of such requirements? Such a preemption we enthusiastically embrace but with reservations as outlined. In terms of offering suggestions on how to address our concerns, it is unclear how the normalization issue is resolved without adding further complexity to creation of the CIA-complexity that we oppose.
Response:		

2. Do you agree with the approach in the proposed NERC Cost Effective Analysis Process (CEAP)? If you disagree, please explain your concerns and provide specific suggestions for addressing the concerns.

Summary Consideration:

Organization	Yes or No	Question 2 Comment
PNGC Comment Group	Yes	
ELCON and Occidental Energy Ventures	Yes	Comments: Industrial Consumers are comfortable with the approach. It is very important to get started at least attempting to estimate the additional costs and benefits of Reliability Standards. However we believe that this must be an iterative process. The intent is to conduct a rough-order Cost Impact Analysis (CIA) and later a more detailed Cost Effectiveness Assessment (CEA). To us, this means focusing on the expected changes in costs and BES benefits (or marginal costs and benefits - not total costs and benefits). If real life experience demonstrates that the job is much bigger than originally anticipated, NERC should be ready to re-evaluate the approach. After the standard takes effect, the actual improvement in BES reliability must be measured against the projected numbers. These findings can be used to develop even better methods to estimate costs and benefits in future initiatives.
Response:		
MRO NSRF	Yes	This approach is needed within the development of a Standard, but should not slow down the time that will be allotted for developing a Standard. It may be difficult to get a true Cost Impact Analysis (CIA) based merely on a SAR. Usually each requirement will need to be reviewed for the CIA and Cost Effectiveness Assessment (CEA). The NERC SC may wish to “practice” this CEAP on the next newly form SAR which would provide real feedback from the SAR DT and SDT.One key issue is whether this CEAP will represent a cross section of all sectors plus consider the impact to small as well as the big entities. (How does the process adjust for this?)

Organization	Yes or No	Question 2 Comment
Response:		
Bonneville Power Administration		BPA believes that at the time the SAR is being submitted, the requester of the SAR should be required to identify the potential risks that would be mitigated, the potential cost to the industry, and the potential benefits to the industry. This puts the burden of doing some research back on the requester. BPA believes that 30 days may not be an adequate amount of time to review the SAR, given the suggested change. BPA believes that the current process for accepting a SAR only deals with whether or not there is a technical justification for the request and appreciates that the new process would allow the NERC SC to reject the SAR if the cost outweighs the reliability benefits.
Response:		
SPP Standards Review Group	Yes	While we may concur with the process we do have concerns that incorporating such a process into the already very involved and complicated standards development process that seems to take forever to develop new or revised standards, that cost analysis could become burdensome and slow the standards process even more. We need to be sure that precautions are taken and efficiencies realized which allow for the inclusion of the cost analysis process without impeding the overall standards process.At the top of page 4 the Standards Committee Process Subcommittee (SCPS), or some other Standards Committee (SC) designee, is assigned the task of working with NERC Staff in developing the Phase 1 CIA and Phase 2 CEA reports. Given the analytical, somewhat technical and definitely financial nature of these reports, we wonder if the SCPS is the proper place for this type of analysis. Perhaps another subcommittee under the SC should be created to fill this role or at least an ad hoc task force could be established to take on the task. The issue with an ad hoc task force would be continuity from one analysis to another since this will be a continuous process for all new/revised standards.At the bottom of page 4, under 'The final CEAP Report...' section, bullets iv. and v. seem to address technical merit of the proposed standard. Aren't these considerations more in the realm of the Reliability Issues Steering Committee (RISC) as currently being proposed in revisions to the Standards Processes

Organization	Yes or No	Question 2 Comment
		Manual? If so, wouldn't this be a duplicated effort or will these items come from the RISC?On page 5 under the first bullet of the 'NERC Procedure for Cost...' the following phrase is used to describe the assignment of a project which has been turned down for consideration as a standard:'...to the appropriate NERC standing committee (OC, PC or CIPC) or working group for assignment.'The subcommittee has been omitted in the phrase and should be included.
Response:		
Dominion	No	The CEAP appears to be very subjective and seems to rely heavily on NERC Staff to evaluate the industry responses. If NERC Staff views the industry data as insufficient, the document states that "efforts will be made to extrapolate without drawing conclusions." Additional clarity would be helpful in describing this process in the document.
Response:		
Northeast Power Coordinating Council	No	As described the CEAP documentation and decision making process is complex. The actual methodology should be tested using field trials to identify areas of improvement. The field trials should be applied to a number of diverse standards to rate effectiveness. A simplified documentation package with an effective appeals process would promote effective use of the CEAP. Currently the Standards Committee is ultimately left with decision making authority over how to proceed with a Standard. The practice should be modified to include an appeals process so that if industry as a whole is opposed to a Standard there is decision making that is beyond that of the Standards Committee alone. It must be emphasized that the CEAP and Adequate Level of Reliability are dependent on one another, and this cannot be overlooked.
Response:		
ISOs' Standards Review Committee	No	We agree with the need for such a process. What isn't clear is if this analysis is to be done for all new standards projects or just a subset. In general, we agree there should be a common simple triage done with all SARs to estimate their standard's respective cost and benefit. We also believe the phase 1 triage be

Organization	Yes or No	Question 2 Comment
		done for NOPRs and FERC-directed standards to enable informed decisions on pursuing equally effective alternatives or requests for clarification or rehearing. Finally, with the developments in the SPIG, it isn't clear how this fits in with the steering committee.
Response:		
G&T Cooperatives	No	The G&T Cooperatives believe the CEAP should be improved in several respects. (1) As discussed in greater detail below in the G&T Cooperatives' response to Question 3, the first phase of the review does not appear workable during the SAR process, where specific requirements have not been fleshed out. Without knowing at the SAR stage what the specific requirements will be, the costs of implementing a Reliability Standard at that phase are not readily identifiable. (2) There appears to be substantial overlap between the CEAP and the decision making that already occurs in the standards development process. For example, Questions 3 & 6 under the CIA phase (in App. B. of the CEAP proposal) asks about benefits of a Reliability Standard, but these are the same questions that the NERC Staff and the Standards Committee must evaluate when they approve a SAR for formal development of a standard. See Standards Process Manual at 12 ("A Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or the benefit of retiring one or more approved Reliability Standards"). Similarly, Question 1 under the CEA phase (in App. B. of the CEAP proposal) asks about whether a proposed standard will achieve is reliability objective, but there are several steps in the standards development process that address that concern. See id. at 5 (requiring that standards be written to achieve their reliability objectives without undue restrictions or adverse impacts on competitive electricity markets); id. at 5-6 (recognizing that "performance-based" standards are one type of Reliability Standards that define and enforce specific reliability objectives) id. at 32 (requiring review of regional variances to see if such variances achieve the reliability objective of the underlying standard). While the G&T Cooperatives support the idea of assessing the costs and benefits of proposed standards, they would encourage NERC to structure the process to

Organization	Yes or No	Question 2 Comment
		avoid duplication of those assessments that already exist in various phases of the standards development process. Such duplication could lead to wasted effort and/or contradictory assessments of the costs and benefits of proposed Reliability Standards. The CEAP should be better integrated with the existing standards development process to ensure that the assessment of cost effectiveness is itself an efficient process. (3) The CEAP proposal should be revised to allow stakeholders to comment on the CEA report before it is transmitted to the Standards Committee. Under the CEAP proposal at 6, the NERC staff would have the responsibility to compile and aggregate the survey responses into a CEA report that is then transmitted to the Standards Committee for review to determine whether the Standards Committee will remand a proposed Reliability Standard back to the standards drafting team for more work, go ahead with the proposed Reliability Standard, or hold the proposed Reliability Standard in abeyance. Given that process, the CEA report prepared by the NERC staff could have a significant impact on the standards development process. Since the CEA report will be based on individual survey submissions by stakeholders, it would be appropriate to ensure that stakeholders have an opportunity to review the report. This will enable stakeholders to verify that the NERC staff accurately interpreted the data submitted in the individual survey responses, to ensure that overall quality of the CEA report is the best possible, and to ensure that the Standards Committee's deliberations are as efficient as possible.
Response:		
SERC Standards Committee	No	(1)The approach appears to be good, but the lack of detail raises concerns and prevents full endorsement of the proposed process.(2) There is a concern that NERC will ask the industry to serve as a consultant to implement and maintain the CEAP.
Response:		
PPL Corporation NERC Registered Affiliates	No	a. In Step 1, the responsibility of providing a report and recommendation based upon the CIA questions in Appendix B should not rest with NERC Staff, but with industry SMEs. In Step 4, the report and recommendation should not

Organization	Yes or No	Question 2 Comment
		be provided by NERC Staff, but by industry SMEs. However, NERC staff should be available to support the SMEs work.b. Responses to the questions in Appendix B should be reported separately for each of the groups covered by the draft standard (GOs, TOs, TOPs, etc., as applicable), not as a single figure for all of industry, to help identify where standards that may be acceptable on an aggregate basis involve placing an excessive burden on one segment of the stakeholders. In addition, the cost/benefit analysis should consider different industry and organizational structures. For example, the burdens placed on a vertically-owned utility and an independent generator for a particular standard may be very different. Additionally, there are differences between ISO/RTO and non-ISO/RTO regions (e.g., black start compensation). Such differences should be considered in assessing the cost and benefits.
Response:		
ACES Power Marketing Standards Collaborators	Yes	
Southwest Power Pool Regional Entity	Yes	
ARIZONA PUBLIC SERVICE COMPANY	Yes	
National Association of Regulatory Utility Commissioners (NARUC)	Yes	The ideal is to have a fully quantified ratepayer impact analysis. However, the proposal - as the introduction identifies - is a good "initial step" that puts the standards development process on the right road. We expect NERC to build on this process over time as experience is gained and stakeholders become use to calculating and providing the cost and benefit data.
Response:		
PacifiCorp	No	PacifiCorp is uncomfortable that the proposed NERC CEAP is being developed in a silo and does not properly account for ongoing activities of NERC and other regulatory bodies, such as those activities associated with the Adequate Level of Reliability (ALR) development and other reliability cost and benefit assessments. Another general concern is that a micro-level evaluation of any given proposed revised standard may not reflect the choices, value, or full impact that standard may have if another complementary standard were being considered. Draft standards are typically developed apart from other emerging

Organization	Yes or No	Question 2 Comment
		standards; continuing to propose more inter-related standards that are not coordinated with other standard drafting efforts will only undermine the effectiveness of the process.Finally, PacifiCorp is concerned about the costs incurred by individual entities for developing cost estimates and their value as part of the CEAP. Regulatory bodies continue to add to registered entities' administrative costs that add no appreciable value, but yet are solely developed and implemented for the purpose of proving a case for maintaining compliance. These efforts generally have substantial costs to the resource-strapped industry and its customers with no apparent reliability benefit. The CEAP should clearly outline significant benefits for the industry to encourage the voluntary participation needed among registered entities.
Response:		
Salt River Project	No	The first two paragraphs of the Executive Summary outline an excellent set of two assessments focused first on feasibility and then on cost. However the Phase 1 and Phase 2 definitions, questions, and information to be collected outlined in the proposed standard stray from the intent of the first two paragraphs of the Executive Summary. Therefore, we recommend the first assessment be re-titled "Feasibility Assessment" to reflect the intent of the CEA Process. See our answer to Question #3 below for more details.
Response:		
Southern Company	Yes	
National Rural Electric Cooperative Association (NRECA)	No	NRECA has the following questions that need to be answered in order for us to determine our support for the approach in the CEAP.1. Which department at NERC developed/is responsible for the draft CEAP?2. According to the documents provided for review NERC staff will approve the CEAP. Please identify the NERC staff that will have this role and provide the basis/measure that NERC staff will use for such approval?3. According to the documents provided for review the CEAP would allow for the industry to propose a less costly and equally as effective/efficient standard or requirement for consideration. However, there may be instances where stakeholders believe the standard is not needed regardless of the cost impact. How would such a

Organization	Yes or No	Question 2 Comment
		position be addressed under the draft CEAP?
Response:		
Dynegy	Yes	Initial thought is it looks complicated (not wrong just complicated).
Response:		
Entegra Power Group LLC	Yes	All bureacratic processes seem to always increase in size and cost. Therefore, even the CEAP should continually be limited and assure cost effectiveness in its objectives.
Response:		
Central Lincoln	Yes	
Cowlitz County PUD	Yes	
Trans Bay Cable, LLC	No	Very arbitray in nature. A matrix type system needs to be developed so people are reporting on the same "aspects" of the standard. Getting an idea of where the costs lie should be an important aspect of this process. Due to the "legal" form most standars are writtin in, it takes a lot of technical, operational and legal review just to understand what the standard is asking, what it's trying to achieve and you've not address the VSLs or VRFs. Knowing how much each part of the approval process through implementation and upkeep need to be looked at to better ID where costs lie.
Response:		
Alcoa, Inc.	Yes	
LCRA Transmission Services Corporation	Yes	
American Transmission Company, LLC	No	This approach is needed within the development of a Standard; however, timeframes need to be addressed. How long will or should it take to complete these analyses (both Phase 1 and 2)? Should time periods be assigned?Furthermore, the process should not slow down the time that will be allotted for developing a Standard. It may be difficult to get a true Cost Impact Analysis (CIA) based merely on a SAR. Usually each requirement will need to be reviewed for the CIA and Cost Effectiveness Assessment (CEA). The NERC SC

Organization	Yes or No	Question 2 Comment
		may wish to “practice” this CEAP on the next newly formed SAR which would provide real feedback from the SAR DT and SDT.Also, ATC is concerned whether this CEAP will represent a cross section of all sectors plus consider the impact to small as well as the big entities. (How does the process adjust for this?)
Response:		
Hydro-Quebec TransEnergie	Yes	Hydro-Quebec TransÃ‰nergie agree, but we feel that this process is intimately tied to the ALR process. In other words, what can be done best to obtain an adequate level of reliability.
Response:		
Ameren	Yes	We agree with need for the CEAP process, but have a concern that this may slow down the overall standards' development process. What would be the time line to complete Phase 1 and Phase 2? Would the CEAP process be used for all standards or some standards? We propose a field-testing of the CEAP process on next couple of SAR and/or Standards.
Response:		
Entergy Services	Yes	
NextEra Energy Inc	No	NextEra appreciates the effort the team has made to develop a NERC Cost Effective Analysis Process (CEAP) and field test of the approach in Northeast Power Coordinating Council region. NextEra however believes the current CEAP needs refinement to not be overly burdensome to Registered Entities, NERC staff, and be more efficient, practical and useful. Specifically, NextEra requests that the following refinements be implemented:A. As currently drafted the CEAP relies on Registered Entities providing information and NERC staff analyzing information for every proposed or revised Reliability Standard. Such an approach does not seem practical in light of the well known resource constraints in the industry and at NERC. As an alternative, as noted above, NextEra believes leveraging the expertise in the NERC Planning and Operating Committee to conduct an initial screen of all proposed or revised Reliability Standards can provide the same results the CEAP is seeking without further

Organization	Yes or No	Question 2 Comment
		burdening registered entities and NERC staff. To the extent data from Registered Entities is needed, NextEra suggests that the data be solicited from a representative cross section of Registered Entities, perhaps 5% of all Registered Entities, and extrapolated to industry-wide level. Sampling could rotate among Registered Entities so that the burden is shared.B. Implementation of a bright line, objective cost-benefit test. In terms of projected benefit, the appropriate criterion would the expected incremental reduction in lost load in MWh from adopting a proposed Reliability Standard times the value of lost load in $/MWh. Without a stated benefit test, the CEAP appears only to be an evaluation of cost and inherently could not be a measure of "cost effectiveness. NextEra notes that the incremental value of a new Reliability Standard is likely to be very low. The totality of non-weather transmission-related load loss averages less that 10,000 MW per year (NERC 2012 State of Reliability, Figure 32). Using a ballpark average load loss of 3 hours, and the value of lost load of $3,500/MWh accepted by FERC in a Midwest ISO order, 123 FERC Â¶61,070, at P 26 (2008), the total cost of all transmission-related outages is about $100 million. There are an estimated 3,800 requirements currently in effect, so there is about $26,000 of lost load for every requirement. Even this dollar amount is too high because there is likely a diminishing marginal return from additional requirements, and some level of outages is presumably unavoidable no matter how comprehensive the inventory of requirements may become.The cost effectiveness process should recognize that the marginal benefit of additional requirements is likely to be very small. It is therefore important that estimating benefit be mandatory. If a SAR sponsor does not provide a benefit estimate based on projected reduction in lost load then a default value could be used such as $26,000/year. C. The refinement of the number of questions asked and data requested of Registered Entities. Even with the implementation of an initial screening tool, as suggested above, the CEAP should be refined to focus on only a few essential questions and requests for data. If the questions and requests for data are not refined, the CEAP will likely not be successful, because Registered Entities do not possess the resources to respond to all the CEAP data and informational requests. In addition, as noted above, a sampling process should be used

Organization	Yes or No	Question 2 Comment
		rather than surveying the entire universe of Registered Entities. (See response to question 4 for a specific proposal)D. NextEra notes that as part of the Adequate Level of Reliability there was a socioeconomic paper submitted that addresses similar issues to that set forth in the proposed CEAP. NextEra suggests that the CEAP team combine its efforts with the socioeconomic paper team so that there are not two similar efforts occurring at the same time.
Response:		
Public Service Enterprise Group	No	A cost analysis itself can be costly to perform. Each SAR does not necessarily need a cost assessment - for example, SARs that are a result of FERC directives. Second, we do not believe that SARs generally have sufficient detail to perform a cost analysis since the standard is yet to be written. A decision to perform a cost analysis at the SAR phase should be delegated to the Operating Committee, Planning Committee, or Critical Infrastructure Protection Committee depending on the technical area impacted. Other cost analysis decisions could be deferred to stakeholders via comments when the standard (not the SAR) is first posted for comment. For example, if 2/3 of the commenters ask for a cost-impact analysis, then one should be performed. The Standards Process Manual should be revised to include criteria on when a cost analysis is warranted.
Response:		
Liberty Electric Power	Yes	
City of Austin dba Austin Energy	Yes	
ISO New England	No	While we agree with parts of the approach, as described by the material provided, the CEAP documentation and decision making process appears complex. The actual methodology should be tested using field trials to identify areas of improvement. The field trials should be applied to a number of diverse standards to rate effectiveness. In the current process the Standards Committee is ultimately left with decision making authority over how to proceed with a Standard. The practice should be modified to include an appeals process so that if industry as a whole is opposed to a Standard there is decision making that is beyond that of the Standards Committee alone. In the

Organization	Yes or No	Question 2 Comment
		end a simplified documentation package with an effective appeal process would promote effective use of the CEAP goals.
Response:		
Exelon Corporation	No	Additional information is necessary to properly assess the CEAP proposal. Please see response to Q5.
Response:		
Puget Sound Energy, Inc.	Yes	Puget Sound Energy agrees in theory with the proposed NERC Cost Effective Analysis however, what appears to be missing from the draft CEAP is a weighted analysis of entity responses based on size of the entity or region in which they are located. Different regions have different risks to reliability, and those regional respondents' answers should be taken into consideration when determining the cost & impact of implementing a proposed standard or requirement. Perhaps this is part of the analysis performed by NERC when reviewing the entity responses, but the proposed CEAP does not clearly indicate what analysis will be performed or if that analysis will be shared with entities prior to forming a Standards Drafting Team.Potential timeframes for each phase of the CEAP have not been addressed. If entities are not given adequate time to formulate well developed responses, the likelihood of entities overestimating potential costs may increase.
Response:		
Electricity Consumers Resource Council (ELCON)	Yes	We could have answered "yes" or "no." The overall approach seems to be very subjective, but it is not clear if a more rigorous approach is even feasible given the huge uncertainties associated with "benefits" and the fact that utility investments tend to be "lumpy" out of necessity. Nonetheless, ELCON appreciates the emphasis on cost determination and achieving the most cost effective solutions.
Response:		
MISO	Yes	MISO agrees with the need for such a process. What is not clear is whether this analysis is to be done for all new standards projects or just a subset of

Organization	Yes or No	Question 2 Comment
		those projects. To this end, MISO respectfully submits that there should be a basic cost assessment performed for all SARs to estimate the proposed standard's potential costs and benefits. This assessment would also be performed for all proposed standards revisions and additions, including those changes being proposed in response to Federal Energy Regulatory Commission (FERC) directives. The cost assessments provided at the commencement of a project should be coordinated with the activities of the Standards Process Input Group to ensure synergies, and avoid duplication, of effort.
Response:		
New England States Committee on Electricity	Yes	NESCOE believes that the CEAP presents a reasonable initial approach to incorporating cost considerations as part of the reliability standards development process. Because achieving the right balance of cost and reliability is a difficult task, NESCOE expects that the CEAP will be subject to continued reassessment and refinement following its implementation. We look forward to continuing to work with NERC on modifications to this critical decision-making tool, and we offer below some preliminary suggestions:(1) With respect to Phase One, there is no information provided in the draft CEAP regarding the decisional standard that the Standards Committee will apply in determining whether the standard development process for a particular proposed standard should continue to be pursued into Phase Two. Clarity should be provided in this area.(2) Also regarding Phase One, because the CIA serves as an initial screen to determine whether the standard development process should continue to be pursued or whether another approach is warranted, the survey questions for Phase One (reflected in Appendix B) should attempt to assess the probabilistic risk that an event will occur. One suggestion would be to ask Question #6 from the Phase Two survey at the Phase One stage.(3) On page 4 of the draft CEAP, various sources of information are listed that staff may rely on to develop a report or make a recommendation in connection with the CEAP. NESCOE believes that interested entities should have a full understanding of all assumptions and extrapolations used in such a report or relied on to make a recommendation. Accordingly, rather than listing only those assumptions or extrapolations

Organization	Yes or No	Question 2 Comment
		"which may skew the results" of a report (see item vii. on the top of p. 5), the report should lay bare all non-protected information relied upon, either in the appendix or elsewhere. While we agree that it would be advantageous for NERC staff to identify such data they believe could "skew the results" of a report, providing access to all information used in the report allows interested entities an opportunity to evaluate whether other assumptions and inputs into the report might similarly warrant heightened scrutiny. (4) Rather than present findings solely in the form of broad national averaging, NERC staff should be diligent in ensuring that cost-benefit analyses take into account regional differences in existing infrastructure or other areas that could distort the costs and associated benefits of a proposed reliability standard. Disparities between regions should be identified and presented in an analysis or report.(5) The draft CEAP also states on the bottom of page 4 that the final CEAP report should consider, in part, the total number of respondents. In the interest of both transparency and clarity, such a CEAP report should provide greater detail in this area. At minimum, the report should include the number of responses received and a sector and regional breakdown of those responses. The credibility of the CEAP will be enhanced by allowing interested entities to evaluate the breadth and diversity of responses received.(6) Similarly, to promote greater transparency and engagement, NERC should include on its website all CEAP reports issued, listed in chronological order.
Response:		
Massachusetts Department of Public Utilities	Yes	The Mass DPU believes that the CEAP presents a reasonable initial approach to incorporating cost considerations as part of the reliability standards development process. Because achieving the right balance of cost and reliability is a difficult task, the Mass DPU expects that the CEAP will be subject to continued reassessment and refinement following its implementation. We look forward to continuing to work with NERC on modifications to this critical decision-making tool, and we offer below some preliminary suggestions:(1)With respect to Phase One, there is no information provided in the draft CEAP regarding the decisional standard that the Standards Committee will apply in determining whether the standard development

Organization	Yes or No	Question 2 Comment
		process for a particular proposed standard should continue to be pursued into Phase Two. Clarity should be provided in this area.(2)Also regarding Phase One, because the CIA serves as an initial screen to determine whether the standard development process should continue to be pursued or whether another approach is warranted, the survey questions for Phase One (reflected in Appendix B) should attempt to assess the probabilistic risk that an event will occur. One suggestion would be to ask Question #6 from the Phase Two survey at the Phase One stage.(3)On page 4 of the draft CEAP, various sources of information are listed that staff may rely on to develop a report or make a recommendation in connection with the CEAP. The Mass DPU believes that interested entities should have a full understanding of all assumptions and extrapolations used in such a report or relied on to make a recommendation. Accordingly, rather than listing only those assumptions or extrapolations "which may skew the results" of a report (see item vii. on the top of p. 5), the report should lay bare all non-protected information relied upon, either in the appendix or elsewhere. While we agree that it would be advantageous for NERC staff to identify such data they believe could "skew the results" of a report, providing access to all information used in the report allows interested entities an opportunity to evaluate whether other assumptions and inputs into the report might similarly warrant heightened scrutiny. (4)Rather than present findings solely in the form of broad national averaging, NERC staff should be diligent in ensuring that cost-benefit analyses take into account regional differences in existing infrastructure or other areas that could distort the costs and associated benefits of a proposed reliability standard. Disparities between regions should be identified and presented in an analysis or report.(5)The draft CEAP also states on the bottom of page 4 that the final CEAP report should consider, in part, the total number of respondents. In the interest of both transparency and clarity, such a CEAP report should provide greater detail in this area. At minimum, the report should include the number of responses received and a sector and regional breakdown of those responses. The credibility of the CEAP will be enhanced by allowing interested entities to evaluate the breadth and diversity of responses received.(6) Similarly, to promote greater transparency and engagement, NERC should

Organization	Yes or No	Question 2 Comment
		include on its website all CEAP reports issued, listed in chronological order.
Response:		
American Public Power Association	Yes	APPA agrees with the approach, but the document needs further editing to clearly explain the process.APPA believes there needs to be a structure within the standards drafting process that oversees the consistent application/evaluation of the results of the CEAP. This structure could be an industry lead working group under the standards committee.
Response:		
KCP&L	Yes	1. In concept, we agree with the approach of the CEAP. However, there is a question of whether the Standard Authorization Request (SAR) will be sufficiently developed to complete a meaningful CIA. This is a concern since the CIAs are used to further advance a SAR to the standard development process. Also, looking at CEAP Phase II, as the requirement is developed and iterative changes incorporated, this requires further Cost Effectiveness Assessment (CEA) development of the requirement. Again, although completed in tandem with the standard development process, iterations are potentially burdensome to the stakeholders as cost studies are revisited. 2. Additionally, on page 3, it states, "If the industry responses were insufficient in the view of NERC Staff when compiling the responses, efforts will be made to extrapolate without drawing conclusions, clearly identifying where this extrapolation may have been done in the final report." This is a concern on two points: One, NERC Staff will use a subjective standard to decide if there is insufficient data and based on that subjective determination, decisions will be made on the furtherance and acceptance of the requirement for continuing in the drafting process; Two, from a purely statistical view, normalization will not be served by the extrapolation of data, basically providing a number of little value for purposes of decision-making. We offer that NERC Staff not offer extrapolated data to the NERC Board of Trustees (NERC BOT). If there is insufficient data, let NERC Staff so state therefore decisions are not made with insufficient or incomplete data.3. We believe the process would be well served if the position of stakeholders were clearly stated during the CEAP process. We suggest

Organization	Yes or No	Question 2 Comment
		requiring during the comment period stakeholders affirmatively indicate they are opting out of completing a CEA and/or, do not believe the cost of implementation is material. In the event 65% of the voting members opt out or state the cost is immaterial, no CEAP document is presented to NERC B.O.T. in consideration of the requirement. Furthermore, we suggest NERC Staff may not present CEA data to the NERC B.O.T. in consideration of a requirement in the event fewer than 35% of the voting members provide a CEA.
Response:		

3. The NERC CEAP incorporates two separate phases of reviews: • The first phase is the Cost Impact Analysis (CIA) which is intended to be an assessment to determine the relative cost impacts of a particular proposed course of action. This is not intended to be a comprehensive cost benefit analysis but rather to identify potential cost magnitude and achievement of ALR and risk mitigation benefits • The second phase is the Cost Effectiveness Assessment (CEA) which may be considered a more detailed assessment whose purpose is to provide information about the relative effectiveness and cost impacts of different approaches to eliminating disparities, increasing life expectancy or of any program or initiative and to provide the industry to offer more cost efficient alternatives to achieve the same reliability objective of the standard. Do you agree with the 'two separate phases'? If you disagree, please provide suggested changes.

Summary Consideration:

Organization	Yes or No	Question 3 Comment
PNGC Comment Group	Yes	
ELCON and Occidental Energy Ventures	Yes	Comments: Industrial Consumers are comfortable with the approach. During the first stage, the rough-order CIA approximation will be sufficient to determine whether the initiative is viable and that development should begin. When requirements have been proposed, the detailed CEA analysis can assure that the original estimates were viable and that the project should move ahead. In both cases, those conducting the CIAs and CEAs should focus on the marginal costs and benefits as the almost infinite "benefits" of avoiding a cascading outage could be used to "justify" nearly any cost.
Response:		
MRO NSRF	Yes	Please review the responses provide in question 2 of the comment form and another key issue is timeframes. How long will or should it take to complete these analyses (both Phase 1 and 2)? Should time periods be assigned?
Response:		
Bonneville Power Administration	Yes	
SPP Standards Review Group	Yes	
Dominion	No	Dominion does not agree that the CEAP could be conducted in two separate

Organization	Yes or No	Question 3 Comment
		phases. The First Phase questions are being posted during the Standard Authorization Request (SAR) stage of the standard project. Typically a SAR is more conceptual and has not been refined into requirements. Therefore, questions related to requirements (Appendix B CIA Questions 4 & 6) appear premature. For the same reasons, it would be difficult at this stage to determine if the standard (since it does not exist) would achieve an adequate level of reliability or estimate potential cost impacts (Appendix B CIA Questions 2 & 3), even at a high level. At best, Dominion believes that Appendix B CIA Questions 1 & 5 could be answered at this stage, although providing little if any estimated cost benefit. For these reasons, Dominion suggests that CIA at the SAR stage would be ineffective and recommends that the CIA and CEA question should be combined and conducted once the standard requirements are developed enough for industry to adequately gauge cost impact.
Response:		
Northeast Power Coordinating Council	Yes	It appears to be appropriate to have two separate phases. As stated in the write-up, this would allow for changing the approach from developing a mandatory standard to instead providing a technical guideline or whitepaper if the cost/benefit of a standard is inadequate. In cases where a standard was deemed unnecessary the workload associated with cost development would be reduced.
Response:		
ISOs' Standards Review Committee	Yes	We agree with the two separate phases. In fact, we believe the initial phase should be done by a group of SMEs, under the direction of the SC or RISC prior to the assembly of a drafting team. The first-cut analysis should be posted along with the SAR. Comments on the SAR and the analysis would help determine the value and need for the proposed standard.
Response:		
G&T Cooperatives	No	The G&T Cooperatives believe that the two phases as they are outlined in the CEAP proposal do not appear to be workable. (1) In particular, the CIA process which takes place at the SAR stage may occur too early in the standards development process to yield any useful cost information. It would be difficult, if

Organization	Yes or No	Question 3 Comment
		not impossible, to assess the costs of a proposed Reliability Standard at the SAR approval stage of the standards development process, because at that time, specific requirements have not been written. Accordingly, there is no basis at that stage to estimate costs. (2) The G&T Cooperatives support identification of costs at the earliest possible stage in the standard development process, the CIA stage seems better served to assess and quantify the benefits, such as reliability, financial or corporate security benefits, that are anticipated to result from the development of a Reliability Standard. The assessment of estimated costs should be moved to a later stage in the standards development process, when specific proposed requirements have been written and when there is a basis for making cost estimates. This assessment can occur at the CEA phase, or better yet, the assessment of costs should take place at a middle phase after the initial drafting of the requirements but before the proposed Reliability Standard is ready for ballot (and while there is still an opportunity to consider alternative requirements). (3) G&T Cooperatives would also note that the CEAP proposal seems only to provide for considerations of alternatives at the CEA phase, which may be too late in the process. See CEAP Proposal at Appendix A (Question 2 under Typical CEA Technical Survey Questions and Question 3 of "Typical" CEA Cost and Implementation Questions). As noted above, while the SAR approval process may be too early for consideration of specific requirements or their alternatives, that early stage in the process may be appropriate for consideration of the anticipated benefits of a possible Reliability Standard as well as alternatives to having a standard (such as the development of an industry advisory or recommendation as part of NERC's alert process). It would also be helpful during the drafting stage to consider the costs of alternative requirements. This would further support the idea, noted above, that there should be a middle phase of the CEAP to assess cost information about specific requirements and their alternatives sometime after the SAR has been approved but before the proposed Reliability Standard and the CEA Report are presented to the Standards Committee. In essence, the consideration of alternatives is important to ensuring that the Reliability Standards are as cost effective as possible and should occur throughout the standards development process (not just at the end).

Organization	Yes or No	Question 3 Comment
Response:		
SERC Standards Committee	No	(1)Additional detail is needed before we can endorse the proposed process.(2) As stated on the CEAP project web page, the proposed process does not include a Cost Impact Analysis (CIA) for current standards that are being revised. There may be cases where a CIA may be appropriate for update of some standards, especially for some of the Version 0 standards that have not been approved by FERC. This should be an option, subject to NERC SC approval on a case-by-case basis.
Response:		
PPL Corporation NERC Registered Affiliates	No	If there are significant differences in costs and benefits between phase one and two, a third phase consisting of a NERC-funded pilot at volunteer entitees could be helpful in obtaining greater certainty on actual costs and benefits.
Response:		
ACES Power Marketing Standards Collaborators	Yes	
Southwest Power Pool Regional Entity	Yes	
ARIZONA PUBLIC SERVICE COMPANY	Yes	
National Association of Regulatory Utility Commissioners (NARUC)	Yes	Providing for a screening level analysis in the initial stages of standard development followed by a more detailed examination of benefits and costs once the standard starts to take shape is a good approach.It is suggested that in both analyses, NERC staff should be looking for areas where the costs and benefits might be disproportionate. Certain regions of the country might be incurring much higher costs; utilities with certain common equipment might be hit harder; etc. An example might be if a GMD standard were to be developed. More northern areas have already made significant investment to mitigate GMDs where the southern areas may not have made much of an investment; benefits from the standard are likely to be disproportionate also. Broad averaging will mask these impacts. NERC staff needs to be looking for these disparities and identify them.
Response:		

Organization	Yes or No	Question 3 Comment
PacifiCorp	Yes	PacifiCorp agrees with NERC that a "fly-over" estimate, the Cost Impact Analysis, followed by a more comprehensive estimate, is appropriate, assuming more than a de minimis percentage of the initial assessments results in a determination that individual projects should not move forward to the standard development and drafting stage. If every new proposed standard is approved for the second phase's Cost Effectiveness Assessment there will be extra costs and no apparent benefit for the industry by introducing the CIA (which is effectively the due diligence phase). NERC should be tasked with developing and periodically reporting on a metric identifying the number of projects that do not move to the second phase as part of the CEAP.
Response:		
Salt River Project	Yes	We like the concept of a two part assessment as described in the Executive Summary; however, the actual name and explanation of the "CIA" generate many concerns. First concern is the CIA would better be labeled FA (Feasibility Assessment) in keeping with the beginning of the 2nd paragraph of the Executive Summary and in keeping with the questions posed in the CIA. As stated on page 5, (paragraph 1) of the CEAP document, the FA (or CIA) report should support a Go/No-go decision on developing a Standard during the evaluation of a SAR. Second concern is it is a misnomer to call the first assessment a "Cost Impact Analysis" as it is not about cost because the requirements have not yet been developed. Rather it is an assessment of the feasibility of the proposed standard and a way to identify alternative methods to achieve the desired reliability benefits. In summary, the first assessment is better identified as a Feasibility Assessment (FA).On Page 5, paragraph 3), Appendix A is called a CEAP Guidance Procedure Document", but on page A, the title of Appendix just "CEAP Guidance Document". After reading through the content of Appendix A, it appears the purpose is more of a checklist with dates for some of the steps. We recommend Appendix A be titled "CEAP Process Checklist" and the items be formatted as a checklist.
Response:		
Southern Company	Yes	

Organization	Yes or No	Question 3 Comment
National Rural Electric Cooperative Association (NRECA)	No	NRECA has the following questions/comments regarding the CEAP documents provided for review:1. We are concerned that cost impacts cannot be accurately determined from language in the SAR which does not include a list of standard requirements. Please explain it is envisioned that costs can be accurately developed from the SAR.2. We disagree with the treatment of existing standards and concluding that they are deemed to be cost effective already. All reliability standards and definitions - new, existing and revised - should be subjected to a cost impact analysis when any work is started on such standards/definitions.3. Under CIA who determines and what basis is used to determine "benefits?"4. The focus on "egregious costs" may be too limited a view of troublesome cost impacts. Please provide additional explanation of why this term was used and consider revising this term to a potentially lower standard of review.5. How will NERC staff compile CIA information? Who will do that? How will minority views be presented?6. What does the following language mean - "eliminating disparities, increasing life expectancy of or any program or initiative?" It is not clear what this language is referring to.7. How will NERC staff evaluate CEA info and produce a CEAP report? Who will do that? How will minority views be presented?8. Cost data will need to be treated confidentially in order to receive useful cost information/data from stakeholders. Without proper protection, stakeholders will be reluctant to provide such information.9. We believe that cost impacts may at times be an obstacle to a standard and may not always point to a different equally effective route. Please consider this important issue as the next draft of the CEAP is developed. 10. A final CEAP report should indicate impacts on smaller entities along with the other issues identified.11. What does "in conjunction with NERC staff" mean? Which NERC staff? To what extent can NERC staff influence the process? Does this provide NERC staff with veto power?12. NERC staff appears to have a very strong role in this process including the submission of their analysis and recommendations in a CEAP report among many roles in the draft process. NRECA is concerned that this substantive role for NERC staff needs to be transparent and representative of all views and comments provided by stakeholders, including minority opinions.
Response:		

Organization	Yes or No	Question 3 Comment
Entegra Power Group LLC	No	I suggest a focus on TOTAL ELIMINATION of Standards which are merely procedural and document collecting in nature. Get back to focusing only on standards providing needed reliability. America is approaching $16 Trillion in debta and it's not rocket science where this behavior will lead. I suggest looking to Europe! Think YOUR children and grandchildren!
Response:		
Central Lincoln	Yes	
Cowlitz County PUD	Yes	
Trans Bay Cable, LLC	Yes	Only if for the first step there is the ability to acknowledge the potential cost variation of the standard. If you say it will cost $2,000, then do step 2 and find out it's $20,000, how far down the road is the standard? What limit to you put on taxpayers for reliability?
Response:		
Alcoa, Inc.	Yes	
LCRA Transmission Services Corporation	Yes	
American Transmission Company, LLC	Yes	
Hydro-Quebec TransEnergie	Yes	
Ameren	Yes	
Entergy Services	Yes	
NextEra Energy Inc	Yes	NextEra favors the two separate phases, provided that the first phase includes the initial screening tool proposed in response to question number 2, and the streamlining of questions and data requests as set forth in response to question number 4.
Response:		
Public Service Enterprise Group	No	We believe that a cost analysis, if done, should be thorough (the equivalent of the second phase of described in the CEAP). It should be undertaken by NERC staff with input from the SDT, but the SDT should be a contributor and not in the lead.
Response:		

Organization	Yes or No	Question 3 Comment
Liberty Electric Power	Yes	
City of Austin dba Austin Energy	Yes	
Essential Power, LLC	Yes	
ISO New England	Yes	In general it appears appropriate to have two separate phases. As stated in the write-up, this would allow for changing the approach from developing a mandatory standard to instead providing a technical guideline or whitepaper if the cost/benefit of a standard is inadequate. In cases where a standard was deemed unnecessary workload associated with cost development would be reduced.
Response:		
Exelon Corporation	No	Additional information is necessary to properly assess the CEAP proposal. Please see response to Q5.
Response:		
Puget Sound Energy, Inc.	Yes	
Electricity Consumers Resource Council (ELCON)	Yes	As stated in the question, we support the purpose of each review.
Response:		
MISO	Yes	MISO agrees with the two separate phases proposed by the CEAP. In particular, MISO supports the two phase approach as it ensures that an assessment of benefit to reliability versus resources will occur prior to SDT members devoting significant time and resources to a low value/low benefit to reliability standard and will ensure that industry, NERC, and Regional Entities can focus efforts on high value/high benefit reliability standards. It further recommends that Subject Matter Experts (SMEs) from a representative group of Registered Entities be enlisted to participate in both phases of the analysis. The participation of SMEs is particularly important in identifying the types of practices and processes that are intended to be in scope for a particular proposal, the relative costs and benefits of those anticipated practices and processes, and any appropriate alternatives that would achieve the same reliability benefit. The identification of these practices and processes (as well as any alternatives) is important because many reliability

Organization	Yes or No	Question 3 Comment
		standards tend to be imprecise and subject to interpretations adopted in the enforcement process that are inconsistent with how the requirements are commonly understood in the industry. Such interpretations tend to ignore cost-benefit considerations, requiring significant expenditures by Registered Entities to achieve compliance, without regard to whether or not there are increased reliability benefits associated with the interpretation or associated expenditures. The participation of SMEs during both phases of the CEAP will help provide clarity regarding what the SDT intended to be required by a proposed standard or standard revision, and avoid after-the-fact enforcement interpretations that ignore cost-benefit issues.
Response:		
New England States Committee on Electricity	Yes	NESCOE believes that a successful implementation of the two-phased approach will provide needed efficiency in screening out projects at the beginning of the standard development process, while providing sufficient information to determine the parameters of a mandatory standard or alternative course of action (e.g., technical guideline or white paper). For example, NERC notes in its Technical Report Supporting Definition of Adequate Level of Reliability, dated April 24, 2012, that "less probable severe events" (e.g., loss of an entire right of way due to a tornado) may not be capable of "any economically justifiable or practical measures to prevent or mitigate" damage to the bulk electric system. In such extreme but low probability cases, Phase One of the CEAP should provide a threshold cost benefit analysis that will inform the continuation of the standards development process or whether other approaches should be pursued to minimize adverse reliability impacts or expedite restoration activities.
Response:		
Massachusetts Department of Public Utilities	Yes	The Mass DPU believes that a successful implementation of the two-phased approach will provide needed efficiency in screening out projects at the beginning of the standard development process, while providing sufficient information to determine the parameters of a mandatory standard or alternative course of action (e.g., technical guideline or white paper). For example, NERC notes in its Technical Report Supporting Definition of Adequate Level of Reliability, dated

Organization	Yes or No	Question 3 Comment
		April 24, 2012, that "less probable severe events" (e.g., loss of an entire right of way due to a tornado) may not be capable of "any economically justifiable or practical measures to prevent or mitigate" damage to the bulk electric system. In such extreme but low probability cases, Phase One of the CEAP should provide a threshold cost benefit analysis that will inform the continuation of the standards development process or whether other approaches should be pursued to minimize adverse reliability impacts or expedite restoration activities.
Response:		
American Public Power Association	Yes	
KCP&L	Yes	Yes, with incorporation of concerns outlined in Questions 1 and 2.
Response:		

4. Appendix B is comprised of standard survey questions for Phase One and Phase Two. Additional questions may be added as appropriate. Do you agree with the survey questions in Appendix B? If you disagree, please suggest questions.

Summary Consideration:

Organization	Yes or No	Question 4 Comment
PNGC Comment Group	Yes	
ELCON and Occidental Energy Ventures	No	We believe this level of shared detail is necessary to allow an in-depth review by all parties. The expectation will be that industry resources will be assigned to those that show a net benefit to reliability - so all participants must be confident with the results.
Response:		
MRO NSRF	Yes	The NSRF would like to thank the CEAP Team for clearly stating that not every issue requires a Reliability Standard. The CIA questionnaire will fall in line with the yet to be improved Standards Process Improvement Group (SPIG) initiative. The Survey Questions in Appendix B should probably be expanded and formalized and become a record once the analyses are completed. Add questions to identify any information that may be considered confidential of CIP related information.
Response:		
Bonneville Power Administration	No	BPA believes that for question 3 for the typical CIA questions, NERC needs to develop a template for guidance on how to respond to this question with possible categories such as labor costs, equipment costs, testing costs, training costs and even a high/medium/low categorization (that could be pre-defined by NERC - similar to what is done with the standards prioritization process). BPA believes that without a template for guidance, industry responses will be very different and it will be difficult to compare apples to apples. BPA also suggests moving the last part of question 3 “and reliability benefits ....” to question 6, which is dealing with the benefits of the standard. Question 6 should be asking about reliability benefits and values ... quantify and qualify these.For question 6 for the typical

Organization	Yes or No	Question 4 Comment
		CEA questions, BPA would like to see high, medium and low pre defined with a dollar range to keep responses consistent and comparable.For the typical CEA Cost and Implementation Questions, question #2 is much like question #3 in the CIA phase - BPA believes that NERC needs to develop a template for guidance on responding to this question with pre defined dollar ranges for high/medium/low cost impacts as well as the appropriate categories for consideration. Having an "other" box would take care of the miscellaneous things.
Response:		
SPP Standards Review Group	Yes	
Dominion	No	As noted in the response to Question #3, the Phase One questions appear ineffective at the SAR phase. The Phase two questions will produce subjective cost information that may or may not produce implementation costs being sought by FERC.
Response:		
Northeast Power Coordinating Council	No	The Appendix B survey questions need to be more focused and request the specific data needed to help ensure complete responses. This will also reduce the amount of response extrapolation required by NERC staff. For the CIA, CEA Typical Questions on page 10:Regarding Question 2, reference is made to the Adequate Level of Reliability definition which is still under development. It is fruitless to comment on this when the ALR itself is still being defined. Revise Question 4 to read: Are there alternative requirement(s) or existing reliability standard requirement(s) other than the proposed requirement(s)to achieve the reliability objective of this proposed standard?Regarding Question 6, sometimes a requirement is not a question of a benefit but rather a response to an order or implementation of a best practice way of working.Typical CEA Technical Survey Questions on page 11:Question 1: Need to further define/clarify the meaning of "effective" to provide direction for the responses to be more focused.Question 2: Same comment as Question 4 above.Question 4: Need to further define/clarify the meaning of "efficiencies" to provide direction for the responses to be more focused.Question 6: Need to further define/clarify the meaning of "probabilistic risk" to enable responses to be more focused. Define the different levels (High,

Organization	Yes or No	Question 4 Comment
		Medium, and Low) and provide examples."Typical CEA Cost and Implementation Questions on page 12:Question 1: Need to replace "in broad general terms" with specific information to be provided in order to focus responses.Question 2 and 4: Provide cost impact ranges, implementation time ranges, and categories of areas that would affect the implementation to help focus responses. It should be made more definitive that the Appendix B CIA questions are to be provided to stakeholders for input. During the CIA portion of the evaluation cost estimates are based on the SAR. It is recognized that at this stage a broad-brushed approach is used but it should be noted that the SAR may not provide complete details for cost development even on an order of magnitude basis. Question 4 in the CIA is the same as Question 2 of the CEA and refers to requirements. The SAR used for the CIA evaluation will not have requirements.
Response:		
ISOs' Standards Review Committee	No	While the data collection in the templates is probably needed, we suggest that the first template should be an "Executive Summary" report (what key information would be provided to the industry and RISC or SC to make an initial determination on the need for the standard). The other templates should collect the necessary information for the Executive Summary template.
Response:		
G&T Cooperatives	No	The G&T Cooperatives believe that the survey questions in Appendix B should be revised to specify in detail the methodology for measuring costs to ensure that responses provide comparable information by entity. Although the process as framed seeks to identify "Industry wide cost impact," the process should recognize that cost impacts (and reliability benefits) may vary substantially by entity size, location, and function. (1) Although the typical questions for the CIA and CEA phases in Appendix B address costs and benefits generally, it is not clear how benefits and costs will be priced out in a way that will allow for meaningful comparisons between the costs and benefits of a specific proposed Reliability Standard as well as meaningful comparisons across all Reliability Standards. To ensure a true evaluation of cost effectiveness, the G&T Cooperatives recommend that the questions incorporate a specific methodology for determining the value

Organization	Yes or No	Question 4 Comment
		of reliability and security benefits and a comparable methodology for measuring costs. (2) The questions appropriately differentiate between start-up and recurring costs. See Appendix B, Typical CIA Question 3 and "Typical" CEA Cost and Implementation Question 2 (differentiating between implementation, maintenance and ongoing compliance resource costs). Nevertheless, within each of these different cost categories, the analysis should also differentiate between those baseline costs that will be incurred by all entities regardless of size and those scalable costs that will vary by entity size, location or function. This additional level of granularity will ensure that those cost impacts that vary by entity size, location, or function are not inadvertently masked by looking at costs on an aggregate level. (3) The CEAP process should not just look at industry-wide impacts, but should also ensure that new standards do not impose unnecessary cost burdens on specific industry segments. NERC should not move forward on a standard that has disproportionate impacts on a class of registered entities because NERC and FERC are obligated under Section 215(d)(2) of the Federal Power Act (16 USC Â§ 824o(d)(2)) to ensure that the Reliability Standards are "not unduly discriminatory." To carry out that statutory obligation, NERC should ensure that the imposition of a particular requirement is cost effective for all applicable entities, regardless of their size, voltage level or location. It is important to note that electric cooperatives raise unique concerns from a cost effectiveness analysis standpoint. Given their size, voltage level and location, the imposition of Reliability Standards requirements on electric cooperatives may have more limited reliability impacts than the imposition of those same requirements on larger utilities or utilities in more densely populated areas. Conversely, because of their smaller size and non-profit status, electric cooperatives are much more cost sensitive than larger, for-profit utilities. Accordingly, even if the benefits of new requirements outweigh the costs on an "industry-wide" basis, NERC should avoid imposing a Reliability Standard in a discriminatory manner, where the costs of that Reliability Standard outweigh the benefits for a particular function or type of entity, such as small entities or entities in rural locations.
Response:		

Organization	Yes or No	Question 4 Comment
SERC Standards Committee	No	(1)Appendix B should clarify that these are sample questions and that not all of the questions must be included in each comment posting.(2)Question 5 of Appendix B needs to be re-worded to address a continent-wide standard instead of a regional standard.
Response:		
PPL Corporation NERC Registered Affiliates	No	The phase-1 and 2 inquires should have added to them the question, "Are there alternative measures that would demonstrate compliance with less burden than those presently proposed, or rephasings that would eliminate uncertainty?" This aspect of compliance is oftentimes not as well developed in draft standards as the technical requirements.
Response:		
ACES Power Marketing Standards Collaborators	No	(1) Under Typical CIA Questions, question 2 is unclear. The first sentence in this question asks two things: "would it achieve an adequate level of reliability "ALR" or exceed this ALR?" It is not clear to which part, "If not why?" applies which is the second sentence. Is NERC asking why the standard doesn't achieve ALR? Or if the standard achieves ALR but also exceeds it, is NERC asking why it exceeds ALR? (2) While we understand the purpose of question 3, we believe what is being asked could be quite time consuming to determine especially for smaller entities that have less resources assigned to compliance.(3) Under Typical CEA Cost and Implementation Questions, the second question regarding the gross anticipated one-time and ongoing cost impacts and reliability benefits could be extremely time consuming to determine for each draft standard. NERC should consider a longer comment period during this phase of the process.
Response:		
Southwest Power Pool Regional Entity	Yes	
ARIZONA PUBLIC SERVICE COMPANY	Yes	
Salt River Project	No	As written, 5 out of 6 questions for the CIA (or Feasibility Assessment) provide information on the feasibility of the proposed standard and possible alternatives to the proposed standard. Question #3 of the CIA survey needs some work. We recommend Q #3 be eliminated for two reasons. First, the Feasibility Assessment

Organization	Yes or No	Question 4 Comment
		is about feasibility and is issued prior to the development of any requirements, so attempting to approximate costs in advance of requirements is premature. Second, half of Q #3 concerns benefits and is a duplicate of Q #6. The "Typical CEA Technical Survey Questions" and "Typical CEA Cost/Implementation Questions" need to be modified. None of the six "CEA Survey" questions has anything to do with cost or benefits. This fact is in conflict with the Executive Summary (first sentence of 2nd paragraph) which states the CEA is to "determine the estimated industry wide cost impacts and potential reliability benefit of requirements in a proposed draft standard". The questions in the "CEA Technical Survey" are significant but not appropriate for a Cost Effectiveness Assessment". These questions could be removed from the CEAP process and instead would be more effective to be included in the SDT postings for comments.From a functional perspective the questions found in the "CEA Cost & Implementation Questions" list should be those that help to develop a true estimate of costs. Estimate formats used for Construction Projects may serve as a guide to develop the questions along with a tabular or spreadsheet format. Otherwise, we have the following comments about the "CEA Cost & Implementation Questions". Q #1. We are unsure why this information is necessary. Some entities may balk about providing this in case it could be used to identify their organization. Replace Q#2 with the 3 following questions: Question A. "What are the life-cycle costs (one time, ongoing, implementation, maintenance) of complying with the requirements? Please provide an estimate in table form if possible." Question B. "What is the on-going impact (after implementation) of complying with the requirements in terms of equivalent full time employees (EFTE)? Question C. "What are the benefits (reliability, labor, materials, administrative) of implementing these requirements?Q #3. We suggest this is a duplicate of the question #2 in the CEA Technical Survey
Response:		
Southern Company	Yes	We suggest adding the following question:1). Does the benefit (in terms of reliability) of the proposed standard outweighs the overall cost to the industry in terms of application, compliance, ongoing monitoring?

Organization	Yes or No	Question 4 Comment
Response:		
National Rural Electric Cooperative Association (NRECA)	No	NRECA requests that our name be added to the parenthetical that includes the names of other industry trade associations and forums. Please also list other trade association groups, including but not limited to EPSA, ELCON, TAPS, LPPC and CEA.
Response:		
Dynegy	Yes	
Entegra Power Group LLC	No	Ask "how do we eliminate reliability 'nice to haves' and reduce the size and scope of NERC Compliance".
Response:		
Central Lincoln	Yes	
Cowlitz County PUD	Yes	
Trans Bay Cable, LLC	No	I think you need to ask if another standard could be modified to include the "reliablity" issue identified. Incorporating into another may be faster, cheaper and less impacting than a new one.Several of the CEA questions are beyond the scope of small utilities. Asking small utilities to perform analysis could be above them, and cause them to shy away from responding allowing large utilities with endless resources to drive standard development.
Response:		
Alcoa, Inc.	Yes	
LCRA Transmission Services Corporation	No	For Phase IUnder Appendix B CIA questions, question 4 should read like question 5 on CEA question survey which says "For any other existing NERC standard, regional standard, Regional criteria, or in-process project draft standard(s), of which your organization is aware?"On CEA survey question 2, it should read like Question 5 of CEA Survey for consistency.On CEA survey question 4, define efficencies or provide more clarity on efficiencies.On CEA survey question 6, what are you really asking? The intent is ambiguous.For Phase IIDescribe the type of your organization ie, Transmission Owner, Generation Owner, etc...Question 2, & 4, provide cost impact and implementation time ranges.

Organization	Yes or No	Question 4 Comment
Response:		
American Transmission Company, LLC	Yes	However, ATC recommends the responses to the Survey Questions in Appendix B be expanded and formalized and become a record once the analyses are completed. Adding questions to identify any information that may be considered confidential of CIP related information should be considered.
Response:		
Hydro-Quebec TransEnergie	Yes	
Ameren	No	(1) To provide even an "order of magnitude" response to potential cost impact question in Appendix B for CIA, an entity would have to make several assumptions as the SAR provides limited information. Our concern is that these assumptions would be different for different entities based on entity type, size, practices, etc. For example, if a SAR is proposing "testing of equipment", a larger entity and a smaller entity would have different population, and unless a testing interval is defined in the SAR, entities may assume different testing periods. We suggest, Appendix B (CIA) to include additional questions or guidance to provide consistency and obtain meaningful information to make decision on. (2) A Webinar may be useful in the first week after issuance of the SAR to get consistency in responses. We recommend that a Webinar be included as an additional step in the CEAP process. (3) While we believe that there is a need for CEAP process and support it completely, we are concern that a quality of the answers would depend on how many other NERC drafts and documents also due for comments and balloting during the same time period. (4) In case of revision of the existing standard, for example going from CIP version 3 to version 4 or version 5, would the CIA step be skipped? (5) We assume that the reasons for the reliability concern are already included in the SAR. If not, they should be added to Appendix B.
Response:		
Entergy Services	Yes	
NextEra Energy Inc	No	Without a refinement of the questions and data requests submitted to Registered Entities, and further consideration of leveraging the NERC Planning and Operating

Organization	Yes or No	Question 4 Comment
		Committees, it is unlikely that the CEAP will be successful. NextEra proposes, therefore, that the following changes be made to the process used to implement Appendix B.On page 10 of the CEAP, questions 1, 2 and 5 (reliability need/technical paper) should part of the initial screening process conducted by the NERC Planning or Operating Committees, and not asked of the entire industry. For proposed or revised Reliability Standards that pass the initial screen of the NERC Planning or Operating Committees, it seems reasonable and useful to seek input from a sample of Registered Entities on questions 3 and 4 (costs and alternative approaches). Conversely, question 6 (possible benefits) is too open ended to likely produce useable results, and thus should be eliminated. On page 11 of the CEAP favors these questions being folded into the initial comment and balloting process, rather than establishing a separate process to seek input on the proposed or revised requirements. Including these questions in the initial comment process is more efficient, and provides stakeholders with ample opportunity to provide the Standards Drafting Teams (SDT) with input on alternative approaches that may be more cost effective. The questions on page 12 of the CEAP should only be asked of the industry after the following conditions have been met: (a) after the SDT has considered the input from the answers to the questions on page 11 and issued a new draft Reliability Standard and (b) only after the Standards Committee (after consulting with the Planning and Operating Committees) votes in favor of requesting a sample of industry to answer the questions on page 12, because it is concerned that the current draft of the proposed or revised Reliability Standard may result in the expenditure of significant level incremental costs that are not cost effective relative to the anticipated reliability benefit.
Response:		
Public Service Enterprise Group	No	See question #2 that relates to ALR. It states “If the standard meets a “reliability related” need would it achieve an adequate level of reliability “ALR” or exceed this ALR as defined by NERC’s ALR approved metrics? If not, why?” First, NERC’s ALR approved metrics have not set minimum levels of performance - they are just showing trends. Second, ALR is not an absolute concept - it is standards-driven. The actual ALR metrics are the result of such standards.

Organization	Yes or No	Question 4 Comment
Response:		
Liberty Electric Power	Yes	
City of Austin dba Austin Energy	Yes	Although we generally agree with the questions set forth, we believe additional -- more detailed -- questions will probably also be needed. We also offer the following suggestions:(1) In Question 4 of the "Typical Questions," you should add "or existing reliability standard requirements" between the words "requirement(s)" and "to achieve."(2) The same comment applies to Question 2 of the "Technical Survey Questions." (3) Question 6 of the "Technical Survey Questions" is virtually impossible to answer. It may be better to ask stakeholders to quantify the risk as "high, medium or low."
Response:		
ISO New England	No	The CEAP Appendix B makes reference to the Adequate Level of Reliability definition which is still under development. It is difficult to comment on this when the ALR itself is still being defined. It should also be made more definitive that the Appendix B CIA questions are to be provided to stakeholders for input. During the CIA portion of the evaluation cost estimates are based on the SAR. It is recognized that at this stage a broad-brushed approach is used but it should be noted that the SAR may not provide complete details for cost development even on an order of magnitude basis. Question 4 in the CIA is the same as Question 2 of the CEA and refers to requirements - the SAR used for the CIA evaluation will not have requirements.
Response:		
Exelon Corporation	No	Additional information is necessary to properly assess the CEAP proposal. Please see response to Q5.
Response:		
Puget Sound Energy, Inc.	No	While the questions do a good job of establishing a high level assessment of a proposed standard, there is not currently a question associated with an entity's assessment of risk for a reliability concern. For example, question #1 is asking a "yes" or "no" question about whether the proposed standard addresses a

Organization	Yes or No	Question 4 Comment
		reliability concern. This question provides no ability for a utility to rank their assessment of the risk (Probability x Impact) associated with the concern and it could be difficult for an entity to respond "no" to that question if there is a small risk associated with the reliability concern, but where an entity doesn't necessarily feel that the low probability warrants the proposed standard. Question #6 asks what the benefits of the proposed standard/requirement would be. It seems that there should also be a question to identify potential risks of implementing the proposed standard/requirement so that the Standards Drafting Team can consider those risks in the refinement of the language of the proposed standard/requirement. Puget Sound Energy also suggests including a question in this section similar to the following:"Is the scope of the proposed standard clear? Are the measures of compliance clear? If not, which requirements or measures are unclear, and why?" Before an entity can assess risk, reliability impacts, and cost, the standard must be clearly defined. A lack of clarity may cause an entity to not respond to the survey and there is not currently a question in the draft CEAP to gauge an entity's understanding of the proposed standard.
Response:		
Electricity Consumers Resource Council (ELCON)	No	Some of these questions (CIA #1 and #2) should be addressed during the SAR drafting process. On questions specific to costs, it might be better to identify more specific, standardized cost components (e.g., Incremental Man-Hours, FTEs, Training, CAPX, Software, Hardward, O&M, Legal, Consultants, Travel, etc.).
Response:		
MISO	Yes	MISO suggests that NERC add questions to the Phase Two inquiry intended to elicit more detail on the types of practices and processes that would be necessary to comply with the proposed requirements up for review. The questions in the existing Appendix B that address cost focus on aggregate cost and aggregate burden, without attempting to inquire about the specific details of compliance. MISO respectfully submits that NERC will need to have that additional detail in order to adequately and accurately assess the costs of complying with a proposed reliability standard or standard revision.

Organization	Yes or No	Question 4 Comment
Response:		
New England States Committee on Electricity	No	As a general comment, we note that Appendix B is almost identical to the same materials proposed by NPCC relative to its procedures to evaluate the cost effectiveness of proposed reliability measures. Like the NPCC questions, the surveys here provide a reasonable framework for evaluating the costs and benefits of a proposed mandatory standard and we look forward to how these materials may be further refined. However, as we state in our comments above in response to Question 2, because the CIA serves as an initial screen to determine whether the standard development process should continue to be pursued or whether another approach is warranted, the survey questions for Phase One (reflected in Appendix B) should attempt to assess the probabilistic risk that an event will occur (i.e., it should ask question #6 from the Phase Two survey). Additionally, in light of the proposed revisions to the definition of Adequate Level of Reliability (ALR) presently being considered by NERC, questions related to the ALR in both surveys should be revisited following any changes to the ALR.
Response:		
Massachusetts Department of Public Utilities	No	In general, the surveys provide a reasonable framework for evaluating the costs and benefits of a proposed mandatory standard and we look forward to how these materials may be further refined. However, as we state in our comments above in response to Question 2, because the CIA serves as an initial screen to determine whether the standard development process should continue to be pursued or whether another approach is warranted, the survey questions for Phase One (reflected in Appendix B) should attempt to assess the probabilistic risk that an event will occur (i.e., it should ask question #6 from the Phase Two survey). Additionally, in light of the proposed revisions to the definition of Adequate Level of Reliability (ALR) presently being considered by NERC, questions related to the ALR in both surveys should be revisited following any changes to the ALR.
Response:		

Organization	Yes or No	Question 4 Comment
American Public Power Association	Yes	APPA recommends that the NERC Cost Effectiveness Analysis Process explicitly address the potential cost impacts of proposed NERC Reliability Standards on small registered entities, by (1) assessing the number of small entities that are potentially subject to each proposed standard, (2) seeking information from small entities concerning the potential costs impacts of the standard, and (3) requesting proposed methods of mitigating or reducing these cost impacts, while ensuring that the reliability objective is achieved. The CEA Technical Survey and Cost and Implementation Questions on pages 12 and 13 of the draft CEAP should be supplemented with additional questions addressing these points. For example, draft question 3 on page 12 could be edited to add the capitalized text below, to become new question 5):"5) Is there an alternative for achieving the reliability objective of the standard with a different requirement OR CHANGES TO THE APPLICABILITY OF THE REQUIREMENT that may result in less cost impact (implementation, maintenance, and ongoing compliance resource requirements) ON SMALL REGISTERED ENTITIES? If so what? Please provide as much additional supporting evidence as possible."The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA), obligates the Federal Energy Regulatory Commission to look at all costs of compliance with a proposed rule or regulation to the extent that such costs are imposed on a "small entity." The SBA Office of Advocacy publishes a guide for agencies entitled "A Guide for Government Agencies: How to Comply with the Regulatory Flexibility Act" ("RFA Compliance Guide"). The most recent version of the RFA Compliance Guide, dated June 2010, can be found on internet at: http://archive.sba.gov/advo/laws/rfaguide.pdf. At page 85, the RFA Compliance Guide June 2010 explains: [a]gencies regulating activities of small entities are required, under section 223 of SBREFA, to establish a policy or program to provide for the reduction (and, under appropriate circumstances, the waiver) of civil penalties for violations of a statutory or regulatory requirement by a small entity. That guide is clear that federal regulatory agencies (including FERC) are responsible for performing an assessment of economic impact that evaluates the regulation's entire effect on small entities, generally defined by the SBA as including all electric utilities with annual sales of less that 4 million MWhs. See Mid-Tex Electric Coop., Inc. v. FERC, 773 F.2d 327 (D.C. Cir. 1985). NERC is not

Organization	Yes or No	Question 4 Comment
		required by law to collect this data, but if the Commission is required to prepare a RFA analysis in its Final Rule on a NERC reliability standard, because the proposed standard has a substantial effect on a number of small entities, a more accurate assessment of the number of affected small entities and the steps that NERC has taken to mitigate such impacts will assist FERC in meeting its obligations on a timely basis. To the extent such analysis or the inputs for such analyses are developed by NERC through its stakeholder processes, it will facilitate efforts to ensure that FERC is confident that NERC has met its obligations as the certified Electric Reliability Organization and that the proposed standard will be supported by stakeholders.
Response:		
KCP&L	Yes	We are comfortable with the questions as long as additional questions more specific to the proposed standard can be appended to the questionnaire.
Response:		
APS	Yes	There should be questions related to quantifying reliability benefits such as reduction in probability of a given MW load loss or cascading.
Response:		

5. Do you have any other comments or suggestions to improve the proposed CEAP?

Summary Consideration:

Organization	Yes or No	Question 5 Comment
PNGC Comment Group		We note the survey questions are targeted to the registered entities that must implement the requirements. The true cost of compliance is not fully covered by these questions to the registered entities, since there are costs to assess compliance, enforce the requirements, process violations, etc. There should be survey questions directed toward the regional entities and the ERO to capture these costs as well.
Response:		
ELCON and Occidental Energy Ventures		Comments: Industrial Consumers expect that the CEAP process may return very accurate cost numbers. The industry's experience with the existing costs of compliance are tangible and well understood. Conversely, we believe the benefit figures will be far more difficult to capture. These are far more difficult to assess - but not impossible. The NERC Events Analysis and Performance Analysis results will be essential to this process, and ultimately to its acceptance by the industry.Secondly, the CEAP process should begin to consider introducing incentives in the Standards Development Process for improvements in automation. Most requirements make no assumption about "how" compliance is achieved - but are often interpreted by Compliance in the most conservative manner. For example, a change in status of BES facilities is instantly provided to neighboring entities via telemetry; but some Regions require a phone call as well. With so many important issues to address, Industrial Consumers believe that automated solutions must be encouraged as much as is possible.Finally, while we believe this is a very important and potentially valuable process, it should be treated as a pilot or trial process until real-life experience demonstrates if value to consumers.

Organization	Yes or No	Question 5 Comment
Response:		
MRO NSRF		Has the CEAP Team looked at applying these questions to currently enforced NERC Standards. Commissioner Moeller has asked the question of cost verse benefit concerning Reliability Standards. This, with section 81 of the Commission's order of 15 March, 2012 concerning FFTs should allow NERC to look at currently enforceable Reliability Standards.What is the EIA411 Report which is referenced several times in this CEAP. Please define when first referenced in the CEAP as this will assist the industry.One of the driving forces behind these analyses should be the revised ALR Definition and reliability of the BES.(Pg.4)The final CEAP Report should include a section on addressing ALR. Does it fill a " reliability gap" ? Formalize the document by organizing the CEAP into Sections. Recommend to add a Table of Contents to make it easier to find the applicable sections.Consider adding a section on disagreement with the SC recommendations and filing appeals. Specify an appeal process and how an entity can submit an appeal for either results of Phase 1 and/or 2.The NSRF reinforces that this is more of a "concept paper" and recommends a detailed implementation at a later date.
Response:		
Bonneville Power Administration		Overall, BPA is in support of this concept and believes it is a necessary step in the right direction. BPA also recognizes that this approach will take considerable time and resources within each entity to respond accurately enough to give a ballpark range of the costs associated with implementation of the standard as well as identifying other possible solutions. An outreach effort (perhaps a webinar) for the industry to collectively participate in and have the opportunity to hear concerns from others might be time well spent during the beginning phase of the process to allow industry leveraging of resources. The standard's impacts on a smaller entity may be vastly different from the impacts to a larger entity. In addition, the amount of staff available to do the analysis will vary greatly between entities as well.BPA believes that a minimum response threshold for path operators and transmission providers should be set/met prior to moving forward with the standard.BPA would also like to see NERC associate the NERC Cost

Organization	Yes or No	Question 5 Comment
		Effective Assessment Process Diagram with the steps outlined in the summary version of the process to make it easier to follow.
Response:		
SPP Standards Review Group		The way the CEAP is proposed a SAR is developed and then fed into the CEAP. Turning the crank of the CEAP provides an analysis that determines what happens with the SAR. How would CEAP, or could CEAP, be used to support the retirement of standards that do not appreciably support the reliability of the BES? Would someone submit a SAR proposing that a standard be deleted and this in turn be fed into CEAP to support such an action? Has the CEAP subgroup considered such an occurrence?
Response:		
Dominion		1. On page 4 in the first paragraph, please spell-out the acronym SCPS (i.e., Standards Committee Process Subcommittee).2. It would be helpful to explain how this NERC Cost Effective Analysis Process (CEAP) For NERC ERO Standards document will be incorporated into the current NERC Rules of Procedure. What is the timeframe of this document being implemented?3. On page 13; NERC Cost Effective Assessment Process: The second box under Step 3 "CEA survey & draft Standard posted for a comment period for stakeholder review and response" should have a periodicity specified for the review and response.4. This entire 9 Step process relies heavily on NERC Staff and NERC Committees, yet there is no timeline in which they have to complete each step in this process, in order to Streamline this process Dominion suggests a timeline also be established for NERC to adhere to.
Response:		
Northeast Power Coordinating Council		The CEAP process will require industry to dedicate additional resources and/or time to provide complete information for the Appendix B survey. This could place additional burden on limited resources.Phase 1 high level Cost Impact Analysis (CIA): Need to further clarify the decision process that the Standards Committee (SC) will use to warrant authorization for or reject moving forward for a standard's development.Phase 2 Cost Effectiveness Impact (CEA): Need to further

Organization	Yes or No	Question 5 Comment
		clarify the basis for determining whether there is or is not sufficient stakeholder response to survey questions in Appendix B.The NERC Procedure for the CEAP of Proposed NERC Reliability Standards (NERC CEAP for NERC ERO Standards -Draft, page 6, section 6, item c) needs to incorporate a time limit for how long a standard can be held in abeyance.Reliability Measures -We have several concerns about developing a BES reliability measure.(1) No specific examples, preferred or alternative method(s), guidelines or supporting discussion were provided in the CEAP draft to allow an entity to determine how it might determine BES reliability impact, effectiveness or cost impact. Please provide at least one example.(2) A methodology for determining BES reliability impact and effectiveness, and for determining cost, would be preferred. The measures LOLE and LOLP are retail service outage measures. They include distribution system performance measures not applicable to BES reliability, and which are non-jurisdictional to FERC and NERC. (3) Retail outage measures, like LOLE/LOLP, are also not suitable as generator outage rate measures.Reliability Impact/Effectiveness - Please provide a reasonably detailed application of a PRA to the BES for both transmission and generation.Consistency - Without a reliability impact/effectiveness framework, without standardized assumptions, without generally accepted methods and practices, entities may use a range of different, even ad hoc approaches to estimate reliability impacts. Cost Impacts - We appreciate the opportunity to incorporate cost effectiveness into the standards development process. Cost is not defined for CEAP purposes. Does cost include first cost (e.g., capital costs), operating cost, overheads, regulatory cost, rate-base and financing costs, tax effects (e.g., depreciation), cash flow, etc.? We recommend that NERC provide general guidance through a Guidance Document that provides instructions and examples and seeks an 'all-in' cost divided into two parts: (1) an initial (e.g., capital) cost, and (2) an annual (e.g., operating) cost.Confidentiality - We understand the need to protect individual entity cost and impact information from potential competitors and from inappropriate financial disclosure. However, the asset owning entities providing the inputs are also those closest to the costs and reliability impacts. Reservedly, we support the desire of the CEAP procedure to have NERC Staff perform the cost/impact aggregation studies. Yet, we are concerned that uneven costs/impacts may not be reflected in any averaging

Organization	Yes or No	Question 5 Comment
		process. Costs/impact may be regional, e.g., WECC only, or may be limited to one segment, e.g., generators. Additional thought needs to go into how these costs/impacts will be reported out, i.e., in whole, by region, by segment, etc.Trading Cost for Reliability - The cost effectiveness analysis process (CEAP) implicitly proposes that there is some optimal and obvious trade-off between the cost and reliability impacts of proposed reliability standards. Clearly, when costs are exceeding high for a small or rare benefit, then a proposed standard or requirement is not cost-effective. Alternatively, if there is little or no cost associated with a large reliability benefit, then the propose standard or requirement is highly cost-effective. However, often the devil is in the details, and between these two obvious extremes there lies a (perhaps not so) "bright line" which divides the more highly cost-effective from the less cost-effective, the more reliability impactful from the less (or negatively) impactful. Presumably, the purpose of CEAP is to identify and promote the more highly cost-effective and reliability-impactful, while avoiding, changing or replacing the less cost-effective and less-reliability impactful with improved reliability proposals. While we may agree with the CEAP concept and approach "in theory," we have concerns about its application "in practice." A number of important questions remain unanswered, such as "How will these "Cost for Reliability" trade-offs be evaluated and effectuated?" "What happens when most of the cost is incurred by one segment, while most of the reliability benefits are captured by another segment (e.g., GO's vs. LSE's and PSE's)?" [Also, substitute "Region" for "segment" in this question.] While we generally agree with the CEAP concept it should be subjected to field trial for a number of diverse standards to access actual performance. It is also important that decision making responsibility with regard to proceeding with development based on cost/benefit be subjected to stakeholder review using an industry appeal process. Simplification of the documentation should be considered as it could also prove worthwhile for actual use of the CEAP principles.NERC should remain mindful of the balance of resources required to plan and operate the electric system along with participation development of new standards which now will also require detailed cost estimates. There is likely to be a good deal of second guessing if the actual costs associated with meeting standards requirements far exceeds the initial cost

Organization	Yes or No	Question 5 Comment
		estimates.One approach that might lessen the burden on staff and prove effective might be to have NERC or drafting teams provide industry with cost estimates and allow industry to approve those cost estimates.
Response:		
ISOs' Standards Review Committee		We believe the summary reports created through this process should attempt to quantify the costs (startup and ongoing of the entire "NERC community") and the expected benefits. If the cost to benefit ratio is high, alternatives to a standard or an alternative approach should be pursued. Costs should include implementation and ongoing outlays, to include compliance administration. We also believe there should be a field test done as soon as possible followed by another opportunity for comment. We would also suggest NERC use the phase one process when it pursues other major initiatives (such as the facility ratings alert).
Response:		
G&T Cooperatives		The reference to the trade associations in Appendix A inadvertently fails to reference the National Rural Electric Cooperative Association ("NRECA") as another entity for "Additional Outreach." The G&T Cooperatives recognize that the listing of trade associations was not intended to be an all-inclusive list, but merely a list of examples. Nevertheless, to avoid confusion as to whether the trade association that represents their interests was intentionally excluded, the G&T Cooperatives suggest that the listing be updated to include explicit reference to NRECA.
Response:		
SERC Standards Committee		(1)With the large number of standards and the wide variation in the reliability benefit achieved compared to the extensive variation in the cost to implement and maintain compliance to the requirements, we suggest that a meaningful cost effectiveness analysis is extremely difficult. Perhaps a cost benefit screen could be used to review current requirements for potential elimination.(2)The comments expressed herein represent a consensus of the views of the above-named members of the SERC Standards Committee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Organization	Yes or No	Question 5 Comment
Response:		
PPL Corporation NERC Registered Affiliates		a. NERC Staff should not be writing the reports and recommendations in either the CIA phase or the CEA phase. These reports and recommendations should be written by industry SMEs.b. CEAP should be applied to existing as well as proposed new standards. There are many requirements that can be improved-on.
Response:		
PacifiCorp		PacifiCorp recommends an approach with a more holistic cost effectiveness initiative, which seems appropriate for the reasons outlined above and would be a valuable tool for the industry and its regulators.
Response:		
Southern Company		We agree with the implementation of new NERC Reliability Standards. However, we believe that this evaluation should be part of a more holistic approach to Standards development. Based on the recent efforts of the P.81 Team and the Standards Process Input Group (SPIG), there are other criteria that, along with cost-benefit and ALR considerations, should be considered in the Standards Development Process. Rather than compartmentalize the evaluation of potential cost impacts, I suggest that these could be considered as part of a broader evaluation of SARs and proposed standards to ensure that new requirements: o Meet the Adequate Level of Reliability criteria o Are cost-effective in meeting the reliability objectives, considering both implementation costs and on-going costs o Are not unduly burdensome or administrative in nature o Are not duplicative of other standard requirements or other regulations
Response:		
Dynegy		I think it may be helpful early on to have a webinar to further summarize and explain this process. I agree with the concept but it looks complicated. Webinar could help explain how much time this is expected to add to an already lengthy process.

Organization	Yes or No	Question 5 Comment
Response:		
Entegra Power Group LLC		Reduce, eliminate, reduce the growth, cut costs EVERYWHERE, etc, etc! We all are in this together. We will all feel the pain someday. Let's get down to business and stop thinking that our debt will be inflated away someday. History tells us the end of this story; it's happened to many great nations before!!
Response:		
Central Lincoln		We note the survey questions are targeted to the registered entities that must implement the requirements. The true cost of compliance is not fully covered by these questions to the registered entities, since there are costs to assess compliance, enforce the requirements, process violations, etc. There should be survey questions directed toward the regional entities and the ERO to capture these costs as well.
Response:		
Cowlitz County PUD		The total cost of compliance not only includes the efforts of registered entities, but also the cost of compliance enforcement. Cowlitz PUD suggests that survey questions directed at the RE's and the ERO to assess costs associated with audits, and processing of violations. Proposed standards may pose particular challenges to audit and enforce. Cowlitz PUD also believes in assessing the applicability scope of a proposed standard, and whether it is best to address a reliability gap to a restricted subset of the BES. Where BES wide application may not be feasible, it may be possible to implement on a small scale and yet yield great benefits.
Response:		
Trans Bay Cable, LLC		Include the evaluation of existing standards. It's great we are looking at new standards, but there are several current standards that have run their course, but yet cost thousands of dollars a year to maintain the program.
Response:		
LCRA Transmission Services Corporation		The CEAP process will tie up entitie's time and resources.So in order for all entities to buy into this process there has to be parameters, more specifically delegate to

Organization	Yes or No	Question 5 Comment
		certain committees, ie. CCC, SDT, etc...The methodology is not concise-there needs to be a cost benefit analysis where all entities can agree upon.
Response:		
American Transmission Company, LLC		1) What is the EIA411 Report which is referenced several times in this CEAP? Please define when first referenced in the CEAP as this will assist the industry.2) Integration of the proposed ALR Definition and reliability of the BES should be considered in the CEAP.3)(Pg.4)The final CEAP Report should include a section on addressing ALR. Does it fill a "reliability gap"? 4) Administrative Comment: Formalize the document by organizing the CEAP into Sections. Recommend to add a Table of Contents to make it easier to find the applicable sections.5) The CEAP Team should consider adding a section on disagreement with the SC recommendations and allow for filing appeals. Specify an appeal process and how an entity can submit an appeal for either results of Phase 1 and/or 2.6) Finally, ATC reinforces that this is more or less a "concept paper" and recommends adding detailed information prior to implementation at a later date.
Response:		
Ameren		(1) We agree this is a move in the right direction by NERC; but, need to be careful that addition of these steps do not significantly extended what seems to be an elongated process already. (2) Integration CEAP with the proposed ALR Definition should be considered. (3) Would there be an appeal process in case there is a disagreement with SC's decision? (4) Would the entity survey responses be confidential? (5) When finalized, would the CEAP process included in NERC RoP? (6) We have received a comment form our Security personnel that the term "Standard Authorization Request" (SAR) needs to be changed. Department of Homeland Security uses the same acronym (SAR) which has stood for "Suspicious Activity Report" for a long time. With the same acronym for two different items, the process could easily be confused.
Response:		
Public Service Enterprise Group		We recommend that the procedure be renamed to "Cost Analysis Procedure" and that the term "Effective" be dropped because the procedure will not weigh a

Organization	Yes or No	Question 5 Comment
		standard's incremental implementation cost with incremental reliability benefits. Per the ALRTF document "Discussion Paper: Risk Tolerance for Widespread BES Outages with Significant Socio-Economic Impacts" such an analysis is not yet feasible. Furthermore, we believe that the process of surveying stakeholders is subject to non-response bias. The SC needs to address this issue in the procedure so that the input of a few voluntary respondents does not outweigh the silence of non-respondents for whom the cost impact may be negligible. Finally, an example would be a great benefit.
Response:		
Liberty Electric Power		The CEAP should take note of the potential cost differences in different sized entities. A small merchant plant typically does not have an engineering staff, and would need to incur the project costs, and expend the time to develop a project. A larger integrated generator would have staff available, and would report a lower cost for the same project due to having staff in-house. Further, the larger entity would likely be capable of developing potential cost information from staff, while smaller merchants would have to use contractors to simply respond to the cost questions. This potentially could lead to an underestimation of the costs to smaller firms as the integrated generators drive the cost analysis. Further, there should be some recognition of the different affects on rate-based entities versus merchant entities. Some respondents will have a cost recovery built into their business model, while merchant plants will not. Finally, there should be some coordination of projects which includes the costs of compliance. Having multiple revisions or new standards which require expenditures in the same fiscal year can strain the resources of smaller entities.
Response:		
City of Austin dba Austin Energy		The CEAP process will require industry to dedicate additional resources and time to provide complete information for the Appendix B survey. Many of us are already stretched quite thin and this process will place additional burden on limited resources. (Nonetheless, it is a good idea)
Response:		

Organization	Yes or No	Question 5 Comment
Essential Power, LLC		Essential Power, LLC agrees with the need to conduct a Cost Benefit Analysis as part of the Standards Development Process. However, as a relatively small entity, we have a number of concerns regarding the gathering and effective analysis of the cost impact data;1. In many cases, smaller entities may not have the in-house expertise to conduct an initial Cost Impact Analysis, and will need to bring in outside assistance to conduct this analysis. This will present significant challenges in providing a useful analysis within 30 days. We suggest that the initial posting period be more flexible, allowing for a period of up to 60 days, dependent upon the specific Standard in question. This will allow smaller entities the time needed to better analyze the impact of the recommended requirements and provide more accurate data to the SDT.2. We are concerned with the composition of the group or team that will review the information gathered through the CEAP process. Although the SDT and NERC Staff are technical Subject Matter Experts on the content of a Standard, they may not have the necessary skill-set to conduct an analysis of the cost information. We recommend that the review team include industry experienced economists or financial analysts to ensure that a complete and effective analysis is conducted.3. The CEAP process needs better defined metrics for determining whether or not a project is cost effective. Some of these metrics may vary from project to project, but there should be a base set of hard metrics that is common to all projects. The metrics included in the current proposal are too vague and high-level to be effective.4. The review team should review the cost impact on different industry groups based on a number of criteria, one of which should be the size of the organization. Smaller entities invest a higher percentage of their resources to implement and maintain compliance to the NERC Reliability Standards; this fact needs to be taken into consideration when implementing the CEAP. We need to ensure that the proposed requirements do not impose an unreasonable burden on smaller organizations.By addressing these concerns, Essential Power, LLC believes that the CEAP process will be much more effective and will be more inclusive of smaller entities.
Response:		
ISO New England		While we generally agree with the CEAP concept it should be subjected to field trial for a number of diverse standards to access actual performance. It is also

Organization	Yes or No	Question 5 Comment
		important that decision making responsibility with regard to proceeding with development based on cost/benefit be subjected to stakeholder review using an industry appeal process. Simplification of the documentation should also prove worthwhile for actual use of the CEAP principles.Again NERC should remain mindful of the balance of resources required to plan and operate the electric system along with participation development of new standards which now will also require detailed cost estimates. There is likely to be a good deal of second guessing if the actual costs associated with meeting standards requirements far exceeds the initial cost estimates.One approach that might lessen the burden on staff and prove effective might be to have NERC or drafting teams provide industry with cost estimates and allow industry to approve those cost estimates.
Response:		
Exelon Corporation		Thank you for the effort to develop a process that incorporates cost impact into the assessment of Reliability Standard development. Exelon appreciates this initial effort and offers the feedback and questions below. Proposed CEAP Process: o Analysis judgment - Within the process, greater clarity on who will judge the analysis results and by what measure/basis is needed. Who and how will NERC staff compile CIA information? How will minority views be presented? o Available resources - the proposal relies on stakeholder input. Operational reality and hands on experience are valuable to inform the assessment; however, resources within the industry are already spread thin on NERC matters. How will this process avoid further stressing resources? o Quality assessments - input is not and should not be mandatory. How will data sufficiency or quality be measured? How will NERC guarantee quantity or quality of input? What backstop measures will be available should the input fall short. Can costs be accurately determined at the SAR level prior to requirements development? o Cost components and perspectives - It is appropriate that cost assessments include implementation, maintenance and ongoing compliance resource requirements. However, the CEAP should look at and consider both industry-wide impacts and functional entity segment impacts to avoid disproportionate (unduly discriminatory) impacts. o Protection of proprietary and market information - the proposal comments on protecting market information; however, the process

Organization	Yes or No	Question 5 Comment
		must discuss how it will protect market information, entity proprietary information and sensitive cost data. If sharing such information raises concerns for entities, they will be unable to provide input. o Impacts on standard development - As an added part of the standards development process, how will the CEAP be incorporated into the standards development revision project underway and how will CEAP support the goal of a more efficient and effective standards process?Process to Develop the CEAP o Additional background on the development of the CEAP would be useful. Who developed the draft CEAP and which NERC department is representing NERC in the effort? o While the announcement email indicates some steps forward, further detail would be useful. Will stakeholders have additional opportunity to provide input on the process? What is the target timeline to develop and roll out the CEAP? A pilot project approach as suggested in the announcement is desirable, though further detail on how the program will be rolled out is needed. Thank you for the opportunity to comment.
Response:		
Puget Sound Energy, Inc.		The flow chart on page 13 of the proposed CEAP indicates in step 1 that "NERC SC publishes the findings of NERC Staff, the SC and the CIA report", but only appears to do this if the NERC SC does not authorize the SAR. Puget Sound Energy recommends that, in the spirit of transparency, the findings of the NERC Staff, the SC and the CIA report be published even if the NERC SC authorizes the SAR.Puget Sound Energy suggests question 4 of Phase I be reworded. Puget Sound Energy believes the goal of this question is to discover if any existing Standards can be modified to include the new requirements being proposed rather than creating a whole new standard. As written it seems to ask for any new future standards that could possibly be thought of to solve the reliability issue.
Response:		
Electricity Consumers Resource Council (ELCON)		NERC might consider retaining the services of the Power Systems Engineering Research Center (PSERC)to help frame a longer term model for CEAP. http://www.pserc.wisc.edu/home/index.aspx

Organization	Yes or No	Question 5 Comment
Response:		
MISO		The reports created through this process should attempt to quantify as accurately as possible the costs (startup and ongoing of the entire "NERC community") and the expected benefits of a proposed reliability standard or standard revision. If the cost to benefit ratio is high, alternatives to the proposal should be pursued.Summary of MISO Comments: o Having a formalized process for determining costs and benefits and meaningfully evaluating these prior to standard development and/or approval would clarify for the industry, NERC, and Regional Entities the considerations and analyses that are appropriate for determining high value/benefit reliability standards and result in the development, revision, or interpretation of the reliability standards that provide the most benefit to reliability. o There should be a basic cost assessment performed for all SARs to estimate the proposed standard's potential costs and benefits, including any changes being proposed in response to Federal Energy Regulatory Commission (FERC) directives. o The cost assessments provided at the commencement of a project should be coordinated with the activities of the Standards Process Input Group to ensure synergies, and avoid duplication, of effort. o SMEs from a representative group of Registered Entities should be enlisted to participate in both phases of the cost analysis proposed by NERC.o The SMEs should focus, in particular, on identifying the types of practices and processes that are intended to be in scope for a particular proposal, the relative costs and benefits of those anticipated practices and processes, and any appropriate alternatives that would achieve the same reliability benefit. o NERC should add questions to the Phase Two inquiry intended to elicit more detail on the types of practices and processes that would be necessary to comply with the proposed requirements up for review.
Response:		
New England States Committee on Electricity		(1) In our comments to NPCC on its CEAP proposal, we stated that NPCC should consider establishing an after-the-fact review process as part of its procedures. We repeat this suggestion here. A collaborative and transparent review of the actual costs and benefits of standards after they are implemented would both

Organization	Yes or No	Question 5 Comment
		bolster the credibility of the process and allow NERC to enhance and improve its CEAP.(2) We understand that some transmission providers supportive of the CEAP have expressed concern regarding their ability to provide detailed cost impact data given resource constraints within their organizations. As one possible approach, ISO New England has proposed shifting the responsibility of providing an initial cost estimate to NERC staff or SDTs, with industry stakeholders then reviewing and approving the estimates. Such an approach may promote a greater level of participation by industry in the voluntary CEAP process. However, it would layer additional obligations and resource challenges onto NERC and/or SDTs. NESCOE suggests that additional discussion among stakeholders is warranted regarding the most efficient process to obtain accurate cost estimates. Irrespective of the process that is ultimately implemented, we repeat our comment in number 2 above that cost estimates should take into account regional differences and not simply be presented as a broad national average.
Response:		
Massachusetts Department of Public Utilities		(1)We agree with NESCOE that NERC should establish an after-the-fact review process as part of its procedures. A collaborative and transparent review of the actual costs and benefits of standards after they are implemented would both bolster the credibility of the process and allow NERC to enhance and improve its CEAP.(2)We understand that some transmission providers supportive of the CEAP have expressed concern regarding their ability to provide detailed cost impact data given resource constraints within their organizations. As one possible approach, ISO New England has proposed shifting the responsibility of providing an initial cost estimate to NERC staff or SDTs, with industry stakeholders then reviewing and approving the estimates. Such an approach may promote a greater level of participation by industry in the voluntary CEAP process. However, it would layer additional obligations and resource challenges onto NERC and/or SDTs. The Mass DPU joins NESCOE in suggesting that additional discussion among stakeholders is warranted regarding the most efficient process to obtain accurate cost estimates. Irrespective of the process that is ultimately implemented, we repeat our comment in number 2 above that cost estimates should take into account regional differences and not simply be presented as a broad national

Organization	Yes or No	Question 5 Comment
		average.
Response:		
KCP&L		1. There is a concern that "Adequate Level of Reliability (ALR)" is undefined. It is not helpful to take this concept before formal regulator and industry acceptance for use to define or explain another draft concept. 2. On page 3, the statement, "...[T]he purpose of the CEAP is...to inform stakeholders of proposed industry cost impact..." While we concur with the examples provided on page 4, i., we question whether an industry-wide cost impact is relevant when the costs by region and to unique entities will vary greatly. As stated in the example, we agree averaging costs would not necessarily be representative of the costs. As previously stated in response to Question No. 1, we wonder how normalization across the industry will be made, previously providing examples of the spectrum of operations that would need to be incorporated into an industry-wide analysis. We add to the example on page 4, i., and suggest costs that are provided to the B.O.T. be a range with costs by region and by entity: if relevant, costs divided by customers served; costs, if relevant, divided by transmission system transmission miles; if relevant, costs divided by number of substations affected by the standard; and/or whatever metrics would seem appropriate to the standard, including CIP standards.
Response:		
APS		There does not appear to be enough emphasis on quantifying reliability benefits. Without quantifying benefits, costs will only help in prioritizing the standards but one would not know if the standard is even needed. The reliability benefits should be quantified in terms of avoiding loss of power to the customer or avoiding cascading.
Response:		

END OF REPORT

From:	Guy V. Zito
To:	laura.hussey@nerc.net; david.kiguel@HydroOne.com; pheidrich@frcc.com; smiller@MEAGPOWER.ORG; apusztai@atcllc.com; weslec@pjm.com; smyers@ercot.com; diane.barney@dps.ny.gov; Katherine.Smith@us.ngrid.com; barbara.nutter@nerc.net; michael.lombardi@nu.com; degraffenriedc@coned.com; Lee R. Pedowicz; Gerard J. Dunbar; Joe Tarantino; Steve@wecc.biz; Stacey Tyrewala
Cc:	amosher@publicpower.org; ben@benli.ca
Subject:	NERC CEAP Comments and Response Assignments due July 23rd
Date:	Wednesday, July 11, 2012 12:50:40 PM
Attachments:	comment_report_CEAP_070912.docx

To All,

If you are in receipt of this email you have expressed some interest in assisting with the NERC Cost Effective Analysis Process. I have attached the comment report developed by Laura. At the SCPS yesterday we were directed to address comments individually, revise the document as necessary and to bring back a revised draft to the SC for approval for a second posting.

In order to maximize the efficiency of the July 25-26 Atlanta meeting I would suggest the following;

Breaking up the five questions that were on the posted comment form to smaller and manageable pieces and assigning each to teams(which the teams can further break down) for completion and submission to Laura and CC me no later than July 23rd. If you are unable to accept the assignment please let me know ASAP so I can reassign things to ensure everything is covered. As you are developing the responses please fill in the attached form and highlight in yellow if your team's response indicates a need to revise the document and bring the ideas for proposed revisions to the Atlanta meeting.

1. Do you agree there should be a formal process to determine the cost of developing reliability standards? If you disagree, please explain why. Comments- Joe and Steve

2. Do you agree with the approach in the proposed NERC Cost Effective Analysis Process (CEAP)? If you disagree, please explain your concerns and provide specific suggestions for addressing the concerns. Comments- Diane and Chris

3. The NERC CEAP incorporates two separate phases of reviews: • The first phase is the Cost Impact Analysis (CIA) which is intended to be an assessment to determine the relative cost impacts of a particular proposed course of action. This is not intended to be a comprehensive cost benefit analysis but rather to identify potential cost magnitude and achievement of ALR and risk mitigation benefits • The second phase is the Cost Effectiveness Assessment (CEA) which may be considered a more detailed assessment whose purpose is to provide information about the relative effectiveness and cost impacts of different approaches to eliminating disparities, increasing life expectancy or of any program or initiative and to provide the industry to offer more cost efficient alternatives to achieve the same reliability objective of the standard. Do you agree with the 'two separate phases'? If you disagree, please provide suggested

changes. Comments - David, Mike, and Scott

4. Appendix B is comprised of standard survey questions for Phase One and Phase Two. Additional questions may be added as appropriate. Do you agree with the survey questions in Appendix B? If you disagree, please suggest questions. Comments - Andy, Cathy, Pete

5. Do you have any other comments or suggestions to improve the proposed CEAP?

Guy, my staff(Lee and Gerry) and Katie

The posted draft CEAP is too big to send in Word as an attachment to this transmittal. We need a way to distribute it. If you want it and have the ability to receive a 9 MB email attachment let me know and I will send it.

Laura can you coordinate the administrative compilation of our proposed team responses into one document and also let me know who will be in direct support of this effort at that meeting, Stacy and/or Barbara?

We will assemble as a group and answer any outstanding unanswered comments, revise the CEAP and I will also report on the meeting with the FERC OER scheduled for July 17th.

Thanks for your help!

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

MEMORANDUM

TO: NERC Standards Process Input Group

FROM: NERC Legal and Standards Departments

DATE: March 15, 2012

SUBJECT: Comparison of NERC Standards Processes with American National Standards Institute Requirements

The following memorandum responds to your request for an evaluation of the North American Electric Reliability Corporation's ("NERC") standards processes compared to the American National Standards Institute ("ANSI") requirements. This memorandum takes no position on whether any particular changes should be made, nor does it express an opinion as to the acceptability of any particular change to the broader stakeholder community.

I. Overview

In sum, there is significant discretion to allow for modification of the NERC standards processes while maintaining ANSI accreditation.[1] However, there are indications that in order to maintain such accreditation in the future, NERC will need to submit at least one standard to ANSI for certification as an American National Standard ("ANS").

The following memorandum separates the NERC Standards Processes into two separate categories: (A) Processes that partially exceed the ANSI Essential Requirements, and (B) Processes that entirely exceed the ANSI Essential Requirements given that these processes are not mandated by ANSI.

A. NERC Standard Processes That Partially Exceed the ANSI Essential Requirements

- Project Initiation
- Comment Periods
- Consideration of Views and Objections
- Successive Balloting
- Weighted-Segment Voting Scheme
- Negative Votes Without Requirements

[1] ANSI Accreditation is defined by ANSI as follows: "The approval by the ANSI Executive Standards Council (ExSC) of the written procedures submitted by a standards developer relative to the development and documentation of evidence of consensus in connection with standards that are expected to be approved as American National Standards. Accreditation by ANSI signifies that the procedures submitted by the standards developer satisfy the essential requirements contained herein." *See* ANSI Essential Requirements at Annex A.

- Ballot Period
- Appeals
- Interpretations Policy
- Expedited Standards Development Process
- Five Year Review

B. NERC Standard Processes that Entirely Exceed the ANSI Essential Requirements

NERC has unlimited discretion to modify the following processes (including removal from the Standard Processes Manual) without affecting its ANSI accreditation because these processes are outside of the scope of the ANSI Essential Requirements:

- Drafting Team Formation
- Standards Committee
- Informal Feedback
- Quality Review
- Non-Binding Polls
- Errata
- Definitions
- Modifications to Standards Procedure
- Compliance Elements
- Field Tests and Collecting and Analyzing Data
- Variance

II. American National Standards Institute

ANSI is the only accreditor of U.S. standards developers and according to ANSI, accreditation signifies that the standards developer is committed to an open, fair and time-tested consensus process that benefits stakeholders. ANSI-accredited standards developers are accredited to the requirements contained in the *ANSI Essential Requirements: Due Process Requirements for American National Standards* ("ANSI Essential Requirements").[2]

ANSI's essential requirements for accreditation as a standards developer are:

- Openness
- Lack of Dominance
- Coordination and harmonization

[2] Available here: http://publicaa.ansi.org/sites/apdl/Documents/Standards%20Activities/American%20National%20Standards/Procedures,%20Guides,%20and%20Forms/2012%20ANSI%20Essential%20Requirements%20and%20other%20Updated%20Procedures/2012_ANSI_Essential_Requirements.pdf.

- Notification of standards development
- Consideration of views and objections
- Consensus Vote
- Appeals
- Written Procedures

It is possible for a standards developer to have two separate standards development processes, one by which American National Standards are processed and one by which other standards are processed. The Standard Processes Manual includes processes for developing standards related to confidential issues, and identifies that these "special standards" will not be filed with ANSI for approval.[3] It is possible for NERC to expand on the types of standards developed through a process that would not lead to submission for ANSI approval, and a separate process that would apply to other reliability standards or Glossary terms that would be eligible for ANSI approval. ANSI accreditation does not require application of the ANSI process to all standard processes.

A. Summary of ANSI Standard Development Process

The following is a brief overview of the ANSI standard development process; additional information relevant to NERC is included in Section IV below.

Step 1: Notification

The ANSI process requires a notification at the initiation of a project that includes an explanation of the need for the project and identification of the stakeholders likely to be directly impacted by the standard. If comments received within 30 days assert that a proposed standard duplicates or conflicts with an existing standard, a deliberation of representatives from the relevant stakeholder groups must be held within 90 days of the comment deadline.

Step 2: Publication and Public Comment

The ANSI Process requires a minimum 30-day comment period following publication in *Standards Action*.[4]

Step 3: Consideration of Written Comments

The ANSI process requires that prompt consideration must be given to the written views and objections of all participants and that each objector must be advised in writing of the

[3] *See* NERC Standard Processes Manual at p. 34-35.

[4] *Standards Action* is the ANSI's key public review vehicle. Published weekly, it provides members and the public with timely, accurate information and enables effective participation in the standards development process - both in this country and internationally. *See* http://www.ansi.org/news_publications/periodicals/standards_action/standards_action.aspx.

disposition of the objection. Each unresolved objection[5] and attempt at resolution and any substantive changes made in the standard must be reported to the consensus body in order to afford all members of the consensus body an opportunity to respond, reaffirm, or change their vote. Comments that are not related to the proposal under consideration must be documented and considered in the same manner as submittal of a new proposal.[6]

Step 4: Consensus Body Vote

Consensus is demonstrated by a vote of the consensus body. All members of the consensus body must have the opportunity to vote and the standards developer's procedures must state specifically how consensus will be determined.[7] Consensus is defined by ANSI as follows:

> Consensus means substantial agreement has been reached by directly and materially affected interests. This signifies the concurrence of more than a simple majority, but not necessarily unanimity. Consensus requires that all views and objections be considered, and that an effort be made toward their resolution.[8]

III. North American Electric Reliability Corporation

NERC is the Electric Reliability Organization ("ERO") certified by the Federal Energy Regulatory Commission ("FERC" or the "Commission") to establish and enforce reliability standards for the bulk-power system. NERC is an international body, recognized in nine provinces in Canada and most of the United States. NERC standards are not effective in the United States until approved by the Commission.

Prior to the certification of NERC as the ERO, the Commission addressed the issue of ANSI accreditation in Order No. 672.[9] The Commission stated (at P 269) that:

> Although we are not requiring that the ERO adopt an ANSI-certified approach to meet all of the requirements of section 39.3, we find that ANSI-accreditation is one reasonable means of doing so. We agree with EEI that a process like the ANSI-certified process would ensure openness and balance the interests of stakeholders. However, we are concerned about the time it may take to develop a

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[5] "Unresolved Objection" is defined by ANSI as "[e]ither (a) a negative vote submitted by a consensus body member or (b) written comments, submitted by a person during public review expressing disagreement with some or all of the proposed standard, that have not been satisfied and/or withdrawn after having been addressed according to the developer's approved procedures." *See* ANSI Essential Requirements at Annex A.

[6] *See* ANSI Essential Requirements at Section 2.6.

[7] *See* ANSI Essential Requirements at Section 2.7.

[8] *See* ANSI Essential Requirements, Annex A.

[9] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

Reliability Standard under the ANSI-certified process. The ERO applicant should address in its application the timetable for developing a proposed Reliability Standard under an ANSI-certified or other process, including the timetable for developing a proposed Reliability Standard that is urgently needed. Moreover, the ERO applicant should also propose a process for modifying or replacing a Reliability Standard (even if interim in nature) in the event that the Commission orders the ERO to modify a Reliability Standard.

Pursuant to Order No. 672, accreditation by ANSI is not required to maintain NERC's status as the ERO. NERC must provide for fair representation of all views in its process for developing a Reliability Standard and must ensure due process, openness and a balance of interests, but NERC is not required by the Commission to follow any particular standards process.[10] The NERC Rules of Procedure require NERC to maintain ANSI accreditation, but NERC does have the authority to modify its rules.[11]

Effective March 24, 2003, NERC's operating procedures were approved for accreditation by ANSI.[12] NERC was then accredited under revised procedures on December 20, 2005. Section 4.1.3 of the ANSI Essential Requirements requires standards developers to maintain one or more approved American National Standards ("ANS"), otherwise the developer must submit its accredited procedures for review and approval on a five-year cycle and must provide a justification as to why it has not submitted any standards to ANSI for approval and why its accreditation remains relevant. As a result of this review, ANSI accreditation may be suspended or withdrawn.

To date, NERC has not submitted any standards to ANSI for approval as American National Standards. In 2011, NERC submitted materials explaining why NERC has not submitted any standards for approval and why the accreditation is relevant. NERC's request for continued accreditation was approved, effective September 9, 2011. Unless NERC submits a standard to ANSI for approval, it will be required to re-justify its accreditation in 2016.

In the background materials relevant to NERC's initial accreditation in 2003,[13] it is clear that ANSI endorsement does not extend to the compliance elements that are developed as part of a standard.[14] There are a number of ways in which NERC's processes differ from ANSI's

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[10] *See* Order No. 672 at P 270.

[11] *See* NERC Rules of Procedure, Section 316, Accreditation: "NERC shall seek continuing accreditation of the NERC Reliability Standards development process by the American National Standards Institute and the Standards Council of Canada."

[12] *See* Notice of Approval of ANSI Accreditation Application, available here: http://www.nerc.com/docs/standards/ANSI/March-24-Approval-Letter-from-ANSI.pdf.

[13] Available here: http://www.nerc.com/filez/ansi.html.

[14] *See* NERC Response to Comments from ANSI Subcommittee on Accreditation at 3 (October 17, 2002)(Commenter #2: "I don't believe that it is appropriate for an ANS [American National Standard] to address consequences of non-compliance with the standard." NERC Response: "NERC does not intend to submit to ANSI for approval as an ANS any of the compliance elements that are developed as part of a standard.").

Essential Requirements that reflect fundamental differences relevant to NERC's mission as an organization as set forth below.

IV. Application of the Essential Requirements of the American National Standards Institute to the North American Electric Reliability Corporation Standard Development Processes

The following NERC processes address various requirements set forth in the ANSI Essential Requirements.

A. Project Initiation

1. ANSI Requirement

The ANSI process requires notification of standards activity via the Project Initiation Notification System ("PINS"), or its equivalent, at the initiation of a project to develop or revise an American National Standard with a statement that includes the following information:

> (a) an explanation of the need for the project, including, if it is the case, a statement of intent to submit the standard for consideration as an ISO or ISO/IEC JTC-1 standard; and (b) identification of the stakeholders (e.g., telecom, consumer, medical, environmental, etc.) likely to be directly impacted by the standard.[15]

If a developer receives written comments within 30 days from the publication date of a PINS announcement in *Standards Action,* and said comments assert that a proposed standard duplicates or conflicts with an existing American National Standard or a candidate American National Standard that has been announced previously in *Standards Action,* a mandatory deliberation of representatives from the relevant stakeholder groups shall be held within 90 days from the comment deadline. Such a deliberation shall be organized by the developer and the commenter and shall be concluded before the developer may submit a draft standard for public review. If the deliberation does not take place within the 90-day period and the developer can demonstrate that it has made a good faith effort to schedule and otherwise organize it, then the developer will be excused from compliance with this requirement.

The purpose of the deliberation is to provide the relevant stakeholders with an opportunity to discuss whether there is a compelling need for the proposed standards project. The outcome of such a deliberation shall be conveyed in writing by the developer and commenter (ideally as a joint submission) to the ANSI Board of Standards Review for consideration should the developer ultimately submit the related candidate standard to ANSI for approval. In the case of ANSI Audited Designators, the Audited Designator shall review the results of the deliberation prior to designating a standard as an ANS. While the outcome is not

[15] *See* Section 2.5 of the ANSI Essential Requirements.

binding, participants are encouraged to develop a consensus on whether and how the standards development project should proceed.[16]

2. NERC Process

A Standard Authorization Request ("SAR") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. Any entity or individual may submit a completed SAR to the NERC standards staff.

The Standards Committee has the authority to post SARs that are limited to addressing regulatory directives, or revisions to standards that have had some vetting in the industry for a 30-day informal comment period with no requirement to provide a formal response to the comments received. For SARs that address the development of new projects or standards, the Standards Committee has the authority to authorize posting the SAR for a formal 30-day comment period. When a SAR is posted for a formal comment period, prompt consideration is given to the written views and objections of all participants.[17]

3. Conclusion

There are several steps in the SAR process implemented by NERC that are not required by ANSI. First, the ANSI process allows for the standards developer, and the standards developer alone, to determine whether a standard is needed. Stakeholders are permitted to comment on whether a proposed standard duplicates or conflicts with an existing standard, but the identification of the need for a standard is solely the responsibility of the standards developer. The ANSI process does not require the standards developer to respond in writing to comments submitted on the standards notification, therefore, the formal comment period provided in the SAR process could be eliminated.

Further, NERC has latitude to decide when it will dissolve a project and begin anew without providing for stakeholder input. For example, following an initial ballot with an extremely low approval rating, NERC could choose to not respond to comments and instead state that comments will be considered in the development of the next draft of the standard. Provided that NERC's communication to stakeholders is clear regarding this process, NERC could start over with the same project and even use the same SAR and draft a new version of the standard. However, in order to implement such a tactic, NERC's Standard Processes Manual would have to provide for this process. Such a modified process would be consistent with NERC's ANSI accreditation.

B. Comment Periods

[16] *Id.*

[17] *See* NERC Standards Processes Manual at p. 13.

1. ANSI Requirement

The ANSI process requires that the comment period shall be one of the following:[18]

- A minimum of 30 days if the full text of the revision(s) can be published in *Standards Action*;
- A minimum of 45 days if the document is available in an electronic format, deliverable within one day of a request, and the source (e.g., URL or an E-mail address) from which it can be obtained by the public is provided to ANSI for announcement in *Standards Action;* or
- A minimum of sixty days, if neither of the aforementioned options is applicable.

2. NERC Process

NERC provides for a minimum of two comment periods. The first formal comment period is at least 30-days long. The Standards Committee has the authority to waive this initial comment period if a proposed revision to a standard is minor and not substantive. The second formal comment period is 45-days long and starts after the drafting team has posted its consideration of stakeholder comments and any conforming changes to the standard.[19] NERC's Standard Processes Manual requires the drafting team to consider and respond to all comments submitted during these formal comment periods.

3. Conclusion

The first formal 30-day comment period is not required by the ANSI process and NERC has significant discretion to modify and/or abolish this requirement.

C. Consideration of Views and Objections

1. ANSI Requirement

The ANSI process requires that prompt consideration must be given to the written views and objections of all participants on the initial announcement of a standards project or public comment listing. An effort to resolve all objections that include comments that are related to the proposal under consideration must be made and each such objector must be advised in writing of the disposition of the objections and the reasoning involved.[20]

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18 *See* ANSI Essential Requirements at Section 2.5.

19 *See* NERC Standard Processes Manual at p. 16.

20 *See* Section 2.6 of the ANSI Essential Requirements:

> In connection with an objection articulated during a public comment period, or submitted with a vote, an effort to resolve all expressed objections accompanied by comments related to the proposal under consideration shall be made, and each such objector shall be advised in writing (including electronic communications) of the disposition of the objection and the reasons therefor.

2. NERC Process

NERC mandates a specific method for responding to every stakeholder comment submitted in response to a formal comment period or submitted with a ballot that includes a proposal for a specific modification to the standard or its implementation plan posted for comment and approval, pursuant to the chart below:

If a Comment:	Then	And
Is unrelated to proposed standard action	Note that comment is unrelated	No further action needed
Proposes change that expands project scope	Note that comment is proposing an expansion	Add item to "issues database" for consideration during next update to the standard
Proposes a modification based on a technical issue not previously identified	Provide the drafting team's technical analysis of the proposal	If the team accepts the proposal, modify the standard
Proposed a modification based on a technical issue previously vetted	Provide a summary of the vetting and resolution previously reached	No further action needed
Proposes a modification to provide greater clarity	Provide the drafting team's view as to whether the proposed modification improves clarity	If the team accepts the proposal, modify the standard

3. Conclusion

The ANSI process does not require NERC to mandate the method by which it will respond to comments. NERC has significant discretion to modify this methodology, however, each objector that includes comments must be responded to in writing, consistent with NERC's ANSI accreditation. NERC has the ability to group comments and submit responses in this manner or to draft a single response that addresses all comments. NERC must respond in writing to each comment, but again, the method by which NERC drafts its response is flexible.

Furthermore, NERC is not required to draft questions for comments by stakeholders. NERC can hold an open solicitation period and accept any comments.

If resolution is not achieved, each such objector shall be informed in writing that an appeals process exists within procedures used by the standards developer.

D. Successive Balloting

1. ANSI Requirement

ANSI requires that when a substantive change is made in a proposed standard, this change must be reported to the consensus body in order to afford all members an opportunity to respond, reaffirm, or change their vote.[21] A "substantive" change is defined by ANSI as "one that directly and materially affects the use of the standard."[22] ANSI provides the following examples of substantive changes below:

- "shall" to "should" or "should" to "shall";
- addition, deletion or revision of requirements, regardless of the number of changes;
- addition of mandatory compliance with referenced standards.

2. NERC Process

NERC provides for a successive ballot process where a substantive change is made in a proposed standard.[23] Pursuant to this process the revised standard is posted for another public comment period and ballot. Comments by the ballot body must be addressed in writing.

3. Conclusion

The successive ballot process is mandated by the ANSI Essential Requirements. However, if a vote on a successive ballot is successful, the standard does not need to be posted for a recirculation ballot. NERC has discretion to eliminate the recirculation ballot following a successful successive ballot and such action is consistent with ANSI accreditation.

E. Recirculation Ballots

1. ANSI Requirement

The ANSI process does not specifically require recirculation ballots, however, this requirement is rooted in Section 2.6 of the ANSI Essential Requirements which requires members of the consensus body an opportunity to change their vote following an unresolved objection.

Unresolved objections are deemed to be satisfied by ANSI when the commenter or negative consensus body voter changes their vote in writing (including e-mail). The Executive

[21] *See* ANSI Essential Requirements at Section 2.6. ("Each unresolved objection and attempt at resolution, and any substantive change in a proposed American National Standard shall be reported to the consensus body in order to afford all members of the consensus body an opportunity to respond, reaffirm, or change their vote.").
[22] *See* ANSI Essential Requirements at Annex A.
[23] *See* NERC Standard Processes Manual at p. 19.

Standards Council of ANSI has stated that for public review commenters only, a developer may provide a written response to a commenter with additional text advising them that if the commenter does not notify the developer that their comment remains unresolved by a specified date, the developer may consider their public comment resolved. Again, this does not apply to unresolved objections from the consensus body; the standards developer must obtain a written change of vote in these instances.

2. NERC Process

NERC provides that members of the ballot pool can be presented with a proposed standard that has not been significantly changed from the previous ballot, along with the reasons for negative votes, the responses, and any resolution of the differences. There is no formal comment period concurrent with the recirculation ballot and no obligation to respond to any comments submitted during this ballot.[24]

The Standards Committee determines whether a proposed modification is "substantive." The NERC Standard Processes Manual states that "[a]n insignificant revision is a revision that does not change the scope, applicability, or intent of any requirement and includes but is not limited to things such as correcting the numbering of a requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a requirement for improved clarity."

3. Conclusion

NERC's recirculation ballot process is consistent with the ANSI Essential Requirements; however, the language with respect to whether a change is substantive exceeds the ANSI Essential Requirements. Again, a "substantive" change is defined by ANSI as "one that directly and materially affects the use of the standard,"[25] therefore, NERC's definition of substantive is more restrictive than ANSI's requirements.

Further, in NERC's responses to comments it might be prudent to consider the inclusion of language indicating that the commenter's objections are deemed to be satisfied by NERC's response unless they notify NERC otherwise within a specified timeframe.

F. Weighted-Segment Voting Scheme

1. ANSI Requirement

ANSI requires evidence of consensus with respect to a vote of the consensus body. Consensus is determined by a standards developer's procedures and all members of the

[24] *See* NERC Standard Processes Manual at pp.19-20.
[25] *See* ANSI Essential Requirements at Annex A.

consensus body must have the opportunity to vote.[26] ANSI defines consensus as the concurrence of more than a simple majority, but not necessarily unanimity.[27]

2. NERC Process

Ballot pool approval of a NERC reliability standard requires:[28]

- A quorum, which is established by at least 75% of the members of the ballot pool submitting a response with an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

The following process is used to determine if there are sufficient affirmative votes:

- For each segment with ten or more voters, the following process shall be used: The number of affirmative votes cast shall be divided by the sum of affirmative and negative votes cast to determine the fractional affirmative vote for that segment. Abstentions and non-responses shall not be counted for the purposes of determining the fractional affirmative vote for a segment.

- For each segment with less than ten voters, the vote weight of that segment shall be proportionally reduced. Each voter within that segment voting affirmative or negative shall receive a weight of 10% of the segment vote.

- The sum of the fractional affirmative votes from all segments divided by the number of segments voting shall be used to determine if a two-thirds majority has been achieved. (A segment shall be considered as "voting" if any member of the segment in the ballot pool casts either an affirmative or a negative vote.)

- A standard shall be approved if the sum of fractional affirmative votes from all segments divided by the number of voting segments is at least two thirds.

3. Conclusion

NERC has significant discretion to modify the methodology by which it measures consensus, but this methodology should be consistent with the principles of balance and a lack of dominance by any single interest category to ensure consistency with ANSI accreditation. A two-thirds majority approval rating is not required by ANSI. Again, consensus is defined by ANSI as more than a simple majority, therefore an approval rating of anything more than 51%

[26] *See* ANSI Essential Requirements at Section 2.7.
[27] *See* ANSI Essential Requirements, Annex A.
[28] *See* NERC Standard Processes Manual at pp. 18-19.

would appear to satisfy the literal terms of the ANSI Essential Requirements, but there is some question as to whether ANSI would approve such a tactic.

G. Negative Votes Without Reasons

1. ANSI Requirement

Section 2.7 of ANSI's Essential Requirements, Evidence of Consensus and Consensus Body Vote, provides that standards developers "are not required to consider negative votes accompanied by comments not related to the proposal under consideration, or negative votes without comments."

2. NERC Process

NERC's process specifically provides for negative votes without reasons.[29] In the background materials relevant to NERC's accreditation, NERC stated that "we believe all voters have the right to cast any vote they wish, with or without reasons. Only 'no' votes with reasons will result in a recirculation ballot."

3. Conclusion

NERC has significant discretion to disallow negative votes without reasons and such action would be entirely consistent with ANSI accreditation.

H. Ballot Period

1. ANSI Requirement

While there is no formal requirement for a minimum ballot period in the ANSI Essential Requirements, informal guidance from ANSI Staff is that the minimum ballot period should be no less than two weeks or 10 business days. This guidance is consistent with Annex B, Section B.1.2.

2. NERC Process

The NERC Standard Processes Manual provides for 10 calendar day ballot windows.

3. Conclusion

NERC may face opposition from ANSI if it attempts to shorten the ballot windows despite the fact that there is no formal requirement stipulating a specific or minimum duration for ballot windows.

[29] *See* NERC Standard Processes Manual at p. 19.

I. Appeals

1. ANSI Requirement

Section 1.8 of ANSI's Essential Requirements requires standards developers to contain an "identifiable, realistic, and readily available appeals mechanism for the impartial handling of procedural appeals regarding any action or inaction. Procedural appeals include whether a technical issue was afforded due process." Section 2.8 of ANSI's Essential Requirements provides for an appeal at the standards developer level and an appeal to ANSI.

2. NERC Process

The Standards Processes Manual provides for both Level 1 and Level 2 appeals. In addition to this, a procedural objection may also be submitted to the NERC Board of Trustees for consideration at the time the Board decides whether to adopt a particular reliability standard, definition, variance or interpretation.[30]

Level 1 is the required first step in the appeals process. The appellant submits to the Director of Standards a complaint in writing that describes the procedural action or inaction associated with the standards process. If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the Director of Standards, the Director of Standards must convene a Level 2 Appeals Panel. This panel consists of five members appointed by the Board of Trustees.[31]

3. Conclusion

The NERC Standard Processes Manual does not explicitly provide for an appeal to ANSI, however, persons who have directly and materially affected interest and who have been or will be adversely affected by any procedural action or inaction by any American National Standard process have the right to appeal to ANSI pursuant to Section 2.8.2 of the ANSI Essential Requirements. NERC has discretion to modify its current appeals process and such action would be consistent with ANSI accreditation.

J. Interpretations Policy

1. ANSI Requirement

Each standards developer is required to have on file at ANSI an interpretations policy, however, the content of that policy is not specified in the ANSI Essential Requirements. Further,

[30] *See* NERC Standards Processes Manual at p. 30.
[31] *Id.*

at least one ANSI accredited standards developer does not have an interpretation policy included in its procedures.

2. NERC Process

NERC's process for interpretations includes two formal comment periods and adoption by the Board of Trustees and none of these steps are mandated by ANSI.

3. Conclusion

NERC has significant discretion to modify the interpretation process and such action would be consistent with ANSI accreditation. For example, the ANSI policy does not require balloting of interpretations.

K. Expedited Standards Development Process

1. ANSI Requirement

None.

2. NERC Process

Under certain conditions where NERC needs to develop a new or modified standard, VRF, VSL, definition, variance, or implementation plan under specific time constrains or to meet an urgent reliability issue, the Standards Committee has authority to approve the following actions to expedite development:

- Shorten the 45-day formal comment period
- Shorten the 30-day period for forming the ballot pool
- Allow significant modifications following the initial ballot without the need for another formal comment period provided the modifications are highlighted before conducting any successive ballot
- Shorten any of the 10-day ballot windows

Following the adoption of a new or modified standard through this expedited process, one of the following three actions must occur:

- If the standard is to be made permanent without additional substantive changes, then a SAR and a proposed standard shall be submitted to the standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay.

- If the standard is to be substantively revised or replaced by a new standard, then a project for the new or revised standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the standard was approved by stakeholders using the expedited process.

- The standard shall be withdrawn through a ballot of the stakeholders within two years of the date the standard was approved by stakeholders using the expedited process.

The NERC Standard Processes Manual states (at p. 33, n. 28) that "[a]bbreviating the final formal comment period or a ballot window violate ANSI's accreditation requirements. The three actions that may be taken to fully process the expedited standard are intended to demonstrate NERC's commitment to meet ANSI's accreditation requirements."

3. Conclusion

There are certain types of standards for which ANSI approval would be either inappropriate or impossible to attain within the requisite timeframe. Standards required to meet regulatory directives or to address urgent reliability issues are likely candidates for such exclusion from the ANSI process. For these types of standards, NERC has the discretion to simply specify in the Standard Processes Manual that such standards will not be submitted to ANSI for approval as American National Standards.

L. Five Year Review

1. ANSI Requirement

An American National Standard is a standard that has been approved by ANSI and meets the criteria set forth in Section 4.2.1.1 of the ANSI Essential Requirements. Section 4.7 of the ANSI Essential Requirements addresses maintenance of such standards and requires standards developers to choose three options: (1) periodic maintenance; (2) continuous maintenance; or (3) stabilized maintenance.

Periodic maintenance is defined as the maintenance of a standard by review of the entire document and action to revise or reaffirm it on a schedule not to exceed five years from the date of its approval as an American National Standard.[32] Continuous maintenance is defined as the maintenance of a standard by consideration of recommended changes to any part of it according to a documented schedule for consideration and action by the consensus body.[33] A standard that is maintained under the stabilized maintenance option shall satisfy the following eligibility criteria:

[32] *See* ANSI Essential Requirements at Section 4.7.1.
[33] *See* ANSI Essential Requirements at Section 4.7.2.

(a) the standard addresses mature technology or practices, and as a result, is not likely to require revision; and
(b) the standard is other than safety or health related; and
(c) the standard currently holds the status of American National Standard and has been reaffirmed at least once; and
(d) at least ten years have passed since the approval or last revision of the standard as an ANS; and
(e) the standard is required for use in connection with existing implementations or for reference purposes.[34]

2. NERC Process

The NERC Standard Processes Manual requires that every standard must be reviewed once every five years from the effective date of the standard or the date of the latest Board of Trustees adoption of a revision to the standard, whichever is later.[35]

3. Conclusion

If NERC were to submit any standards for approval as American National Standards, it would be required to maintain such standards in accordance with the foregoing in order to maintain ANSI accreditation. However, NERC is under no such obligation to maintain non-American National Standards in this manner and is limited only by the terms of the NERC Standard Processes Manual. Therefore, NERC has discretion to modify the application of the five year review process to only American National Standards and such a modification would not be inconsistent with its obligations under the ANSI process.

V. North American Electric Reliability Corporation Processes That Are Not Addressed by the American National Standards Institute

The following NERC policies are unaddressed by ANSI, and therefore, NERC has significant discretion to modify such provisions in the Standards Processes Manual and such action would generally not conflict with ANSI requirements or ANSI accreditation.

A. Drafting Team Formation

1. ANSI Requirement

None.

2. NERC Process

[34] *See* ANSI Essential Requirements at Section 4.7.3.
[35] *See* NERC Standard Processes Manual at p. 41.

The NERC Standard Processes Manual addresses the formation of drafting teams to work on developing a new or revised standard. The drafting team is responsible for making recommendations to the Standards Committee regarding the remaining steps in the standards process.

3. Conclusion

NERC has significant discretion to modify and/or abolish the formation of drafting teams and such action would be consistent with ANSI accreditation.

B. Standards Committee

1. ANSI Requirement

None.

2. NERC Process

The members of the Standards Committee are elected by their respective segment's stakeholders and consist of two members of each of the stakeholder segments of the Registered Ballot Body. The Standards Committee is responsible for managing the standards processes for development of standards, VRFs, VSLs, definitions, variances and interpretations in accordance with the Standard Processes Manual.[36]

3. Conclusion

NERC has significant discretion to modify and/or abolish both the existence and composition of the Standards Committee and its associated duties.

C. Informal Feedback

1. ANSI Requirement

None.

2. NERC Process

The NERC standards development process allows for informal feedback at several stages. For SARs that are limited to addressing regulatory directives, or revisions to standards that have had some vetting in the industry, the Standards Committee can authorize posting a SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments

[36] *See* NERC Standard Processes Manual at p. 8.

received.[37] Drafting teams may also use informal comment periods to collect stakeholder feedback on preliminary drafts of its documents. Such informal comment periods shall have a minimum duration of 30 days and information must be publicly posted. While drafting teams are not required to provide a written response to each individual comment received, drafting teams must post a summary response that identifies how it used comments submitted by stakeholders. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft."[38]

3. Conclusion

NERC has significant discretion to modify and/or abolish the consideration of informal comments and informal comment periods and such action would be consistent with ANSI accreditation.

D. Quality Review

1. ANSI Requirement

None.

2. NERC Process

The NERC Standards Processes Manual requires a quality review of standards to assess whether the documents are within the scope of the associated SAR, whether the standard is clear and enforceable as written, and whether the standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval standards, VRFs and VSLs.

3. Conclusion

NERC has significant discretion to modify and/or abolish the quality review process and such action would be consistent with ANSI accreditation.

E. Non-Binding Polls

1. ANSI Requirement

None.

2. NERC Process

[37] *See* NERC Standard Processes Manual at p. 13.
[38] *See* NERC Standard Processes Manual at p. 15.

NERC conducts a non-binding poll of VRFs and VSLs during the last 10 days of the 45-day formal comment period.

3. Conclusion

NERC has significant discretion to modify and/or abolish the use of non-binding polls and such action would be consistent with ANSI accreditation.

F. Errata

1. ANSI Requirement

None.

2. NERC Process

The Standards Committee has authority pursuant to the Standard Processes Manual, to correct errors that do not change the scope or the intent of the associated standard and where the correction has no material impact on the end users of the standard. The Standards Committee then submits such corrections to the NERC Board of Trustees for approval.[39]

3. Conclusion

NERC has significant discretion to modify and/or abolish the process for correcting errata and such action would be consistent with ANSI accreditation.

G. Definitions

1. ANSI Requirement

None.

2. NERC Process

The NERC Standard Processes Manual provides that any proposal for a new or revised definition shall be processed in the same manner as a standard. Once authorized by the Standards Committee, the definition is posted for at least one 45-day formal comment period and is balloted in the same manner as a standard. Each definition that is approved by the ballot pool is submitted to the NERC Board of Trustees for adoption.

3. Conclusion

[39] *See* NERC Standard Processes Manual at p. 40.

While the ANSI process does not address definitions, given that NERC has historically processed definitions in the same manner as standards, any revisions to this process may be subject to a higher level of scrutiny than would otherwise be warranted. Further, given the framework of NERC's standard process, it is possible to change the meaning and application of standards by altering the meaning of defined terms. Therefore, while there are no ANSI requirements specific to definitions which would suggest that NERC has unfettered discretion to change this process, the reality is that such changes should be evaluated for the potential to alter standards. For these reasons, NERC has discretion to modify the process for defining terms and such action would generally be consistent with ANSI accreditation dependent on the nature of the modifications.

H. Modifications to Standards Procedure

1. ANSI Requirement

None.

2. NERC Process

The NERC Standard Processes Manual addresses the manner in which requests to revise the Standard Processes Manual will be considered.[40] The Standards Committee oversees the handling of each request and responds to each sponsor within 30 calendar days. Proposed revisions are posted for a 45-day formal comment period and based on the degree of consensus, the Standards Committee then has the following four options:

- Submit the revised process or processes for ballot pool approval;
- Repeat the posting for additional inputs after making changes based on comments received;
- Remand the proposal to the sponsor for further work; or
- Reject the proposal.

If the proposed revision is approved by the ballot pool, the Standards Committee submits the revised procedure to the Board of Trustees for adoption.

3. Conclusion

NERC has significant discretion to modify and/or abolish the method for revising the Standard Processes Manual and such action would be consistent with ANSI accreditation.

I. Compliance Elements

[40] *See* NERC Standard Processes Manual at p. 43.

1. ANSI Requirement

None.

2. NERC Process

NERC Reliability Standards include several compliance elements, including compliance monitoring and assessment processes, time horizons, and VRFs and VSLs.

3. Conclusion

NERC has significant discretion to modify the compliance elements of Reliability Standards and such action would be consistent with ANSI accreditation. This process is outside the scope of the ANSI requirements and reflects a fundamental difference relevant to NERC's mission as an organization.

J. Field Tests and Collecting and Analyzing Data

1. ANSI Requirement

None.

2. NERC Process

The NERC Standard Processes Manual provides for field tests and the analysis of data to validate proposed requirements, measures or compliance elements in a reliability standard.[41]

3. Conclusion

NERC has significant discretion to modify its provisions regarding field tests and the collecting and analysis of data and such action would be consistent with ANSI accreditation. This process is outside the scope of the ANSI requirements and reflects a fundamental difference relevant to NERC's mission as an organization.

K. Variance

1. ANSI Requirement

None.

2. NERC Process

A variance is an approved, alternative method of achieving the reliability intent of one or more requirements in a standard. No regional entity or bulk power system owner, operator, or

[41] *See* NERC Standard Processes Manual at 25-26.

user can claim a variance from a NERC reliability standard without approval of such a variance through the relevant standard approval procedure for the variance. Each variance from a NERC reliability standard that is approved by NERC and applicable governmental authorities is made an enforceable part of the associated NERC reliability standard.[42]

3. Conclusion

NERC has significant discretion to modify its provisions regarding variances and such action would be consistent with ANSI accreditation. This process is outside the scope of the ANSI requirements and reflects a fundamental difference relevant to NERC's mission as an organization.

[42] *See* NERC Standard Processes Manual at p. 32.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

~~Revision 1~~

VERSION 3

The proposed revisions to the Standard Processes Manual result primarily from the following recommendations of the Standards Process Input Group (SPIG):

Recommendation 1: American National Standards Institute

NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.

Recommendation 2: Reliability Issues Steering Committee (RISC)

[Assigned to SPIG to develop draft mandate/scope for RISC.]

Recommendation 3: Interface with Regulatory and Governmental Authorities

[Assigned to NERC Management.]

Recommendation 4: Standards Product

- *The Board is encouraged to require that the standards development process address:*
  - *The use of RBS;*
  - *Cost effectiveness of standards and standards development;*
  - *Alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and*
  - *The retirement of standards that are no longer needed to meet an adequate level of reliability.*

Recommendation 5: Standards Development Process and Resources

The Board is encouraged to require the standards development process be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The Board is also encouraged to require standard development resources to achieve and address:

- *Formal and consistent project management*
- *Efficient formation and composition of SDTs*

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Rationale: Section numbers and a version number have been inserted to provide ease of reference

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Listed below is a brief overview of the proposed revisions to the Standard Processes Manual incorporated herein. Sections that are not listed were not substantively changed.

- **Section 2.0**: Elimination of VRFs/VSLs and incorporation of Measures into RSAWs
- **Section 3.0**: Revised drafting team composition to incorporate SPIG recommendation to include lawyers and compliance experts; incorporated SPIG recommendation that drafting teams participate in developing RSAWs and compliance elements.
- **Section 4.0:** Streamlined commenting and balloting process, including:
  - Provisions for providing summary responses to comments and the elimination of the obligation to respond in writing at every stage of the comment process;
  - Elimination of negative votes without comments and negative votes with unrelated comments in the calculation of consensus;
  - Provisions to allow for quality reviews to be conducted in parallel with standard development
- **Section 7.0**: Incorporated guidance regarding the appropriate role and scope of Interpretations, to be consistent with guidance from the NERC Board of Trustees.
- **Section 13.0:** Revised to reduce the requirement for periodic review to be consistent with ANSI minimum requirements.
- **Section 16 (new):** Incorporation of a waiver provision to allow for modifications to the standards development process for good cause.

Section 1.0: Introduction

1.1: Authority

This manual is published by the authority of the NERC Board of Trustees. The Board of Trustees, as necessary to maintain NERC's certification as the ~~electric reliability organization (ERO);~~Electric Reliability Organization ("ERO"), may file the manual with applicable governmental authorities for approval as an ERO document. When approved, the manual is appended to and provides implementation detail in support of the ERO Rules of Procedure Section 300 — Reliability Standards Development.

Capitalized terms not otherwise defined herein, shall have the meaning set forth in the Definitions Used in the Rules of Procedure, Appendix 2 to the Rules of Procedure.

1.2: Scope

The policies and procedures in this manual shall govern the activities of the North American Electric Reliability Corporation ~~(~~("NERC~~)~~") related to the development, approval, revision, reaffirmation, and withdrawal of ~~standards, interpretations~~Reliability Standards, Interpretations, definitions, ~~variances, violation risk factors, violation severity levels,~~Variances, Sanction Table references,[1] and reference documents developed to support standards for the ~~reliable~~ Reliable Operation and planning ~~and operation~~ of the North American ~~bulk power systems.~~Bulk Power Systems.

This manual also addresses the role of the Standards Committee, drafting team and ballot body in the development and approval of compliance elements in conjunction with standard development.

1.3: Background

NERC is a nonprofit corporation formed for the purpose of becoming the North American ERO. NERC works with all stakeholder segments of the electric industry, including electricity users, to develop ~~standards~~Reliability Standards for the reliability planning and ~~reliable operation~~Reliable Operation of the ~~bulk power systems~~North American Bulk Power Systems. In the United States, the Energy Policy Act of 2005 added Section 215 to the Federal Power Act for the purpose of establishing a framework to make ~~standards~~Reliability Standards mandatory for all ~~bulk power system~~Bulk Power System owners, operators, and users. Similar authorities are provided by applicable governmental authorities in Canada. NERC was certified as the ERO effective July 2006. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007).

1.4: Essential Attributes of NERC's Reliability Standards Processes

NERC's ~~standards~~Reliability Standards development processes provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard consistent with the attributes necessary for American National Standards Institute ("ANSI") accreditation. The same attributes, as well as transparency, consensus-building, and timeliness, are also required under the ERO Rules of Procedure Section 304.

- ***Open Participation***
  Participation in NERC's ~~standards~~Reliability Standards development balloting and approval processes shall be open to all entities materially affected by NERC's ~~reliability standards.~~Reliability Standards. There shall be no financial barriers to participation in NERC's

[1] The term "Sanction Table" refers to Appendix 4B to the NERC Rules of Procedure, *Sanction Guidelines of the North American Electric Reliability Corporation* at Appendix A, Base Penalty Amount Table.

~~standards~~Reliability Standards balloting and approval processes. Membership in the ~~registered ballot body~~Registered Ballot Body shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements.

- ***Balance***
  NERC's ~~standards~~Reliability Standards development processes ~~cannot~~shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization is able to defeat a matter.

  NERC shall use a voting formula that allocates each industry ~~segment~~Segment an equal weight in determining the final outcome of any ~~standard~~Reliability Standard action. The ~~standards~~Reliability Standards development processes shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed ~~standard~~Reliability Standard, definition, ~~variance~~Variance, and ~~interpretation~~Interpretation.

- ***Coordination and harmonization with other American National Standards activities***
  NERC is committed to resolving any potential conflicts between its ~~standards~~Reliability Standards development efforts and existing American National Standards and candidate American National Standards.

- ***Notification of standards development***
  NERC shall publicly distribute a notice to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a ~~standard~~Reliability Standard, definition, or ~~variance~~Variance; and for each proposed ~~interpretation~~Interpretation. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on NERC's ~~standards~~Reliability Standards web page. All notices shall identify a readily available source for further information.

- ***Transparency***
  The process shall be transparent to the public.

- ***Consideration of views and objections***
  Drafting teams shall give prompt consideration to the written views and objections of all participants~~, providing individualized written responses to those commenting during formal comment periods and those commenting as part of the balloting process.~~ as set forth herein. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

- ***Consensus Building***
  The process shall build and document consensus for each ~~standard~~Reliability Standard, both with regard to the need and justification for the ~~standard~~Reliability Standard and the content of the ~~standard~~Reliability Standard.

- ***Consensus vote***
  NERC shall use its voting process to determine if there is sufficient consensus to approve a proposed ~~**reliability standard**~~Reliability Standard, definition, ~~**variance**~~Variance, or ~~**interpretation.**~~Interpretation. NERC shall form a ballot pool for each ~~**standard**~~Reliability

Standard action from interested members of its ~~**registered ballot body.**~~Registered Ballot Body. Approval of any ~~**standard**~~Reliability Standard action requires:

- A quorum, which is established by at least 75% of the members of the ballot pool submitting a response with an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted ~~segment~~Segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative and negative votes with related comments or stated objections, excluding abstentions~~ and~~, non-responses~~.~~, negative votes without comments, and negative votes with unrelated comments.

- ***Timeliness***

Development of ~~standards~~Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the ~~bulk power system.~~ Bulk Power System.

- ***Metric Policy***

The International System of units is the preferred units of measurement in NERC Reliability Standard. However, because NERC's Reliability Standards apply in Canada, the United States and portions of Mexico, where applicable, measures are provided in both the metric and English units.

Section 2.0: Elements of a Reliability Standard

2.1: Definition of a Reliability Standard

A ~~reliability standard~~Reliability Standard includes a set of ~~requirements~~Requirements that define specific obligations of owners, operators, and users of the North American ~~bulk power systems~~Bulk Power Systems. The ~~requirements~~Requirements shall be material to reliability and measurable. A ~~reliability standard~~Reliability Standard is defined as follows:

> "Reliability ~~standard~~Standard" means a requirement to provide for ~~reliable operation~~Reliable Operation of the ~~bulk power system~~Bulk Power System, including without limiting the foregoing, requirements for the operation of existing ~~bulk power system facilities~~Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such ~~facilities~~Facilities to the extent necessary for ~~reliable operation~~Reliable Operation of the ~~bulk power system;~~Bulk Power System, but ~~shall~~the term does not include any requirement to enlarge ~~bulk power system facilities~~Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority. *See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.

2.2: Reliability Principles

NERC ~~reliability standards~~Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American Bulk Power Systems.[2] Each ~~reliability standard~~Reliability Standard shall enable or support one or more of the reliability principles, thereby ensuring that each ~~standard~~Reliability Standard serves a purpose in support of reliability of the North American ~~bulk power systems.~~Bulk Power Systems. Each ~~reliability standard~~Reliability Standard shall also be consistent with all of the reliability principles, thereby ensuring that no ~~standard~~Reliability Standard undermines reliability through an unintended consequence.

2.3: Market Principles

Recognizing that ~~bulk power system~~Bulk Power System reliability and electricity markets are inseparable and mutually interdependent, all ~~reliability standards~~Reliability Standards shall be consistent with the market interface principles.[3] Consideration of the market interface principles is intended to ensure that ~~reliability standards~~Reliability Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

2.4: Types of Reliability Requirements

Generally, each ~~requirement~~Requirement of a ~~reliability standard~~Reliability Standard shall identify~~, "What functional entity~~ what Functional Entities shall do ~~what~~, and under what conditions, to achieve ~~what~~a specific reliability objective~~."~~. Although ~~reliability standards~~Reliability Standards all follow this

[2] The intent of the set of NERC Reliability Standards is to deliver an adequate level of reliability. The latest set of reliability principles and the latest set of characteristics associated with an adequate level of reliability are posted on the Reliability Standards Resources web page.

[3] The latest set of market interface principles is posted on the Reliability Standards Resources web page.

format, several types of ~~requirements~~Requirements may exist, each with a different approach to measurement.

- **Performance-based ~~requirements~~Requirements** define a specific reliability objective or outcome achieved by one or more entities that has a direct, observable effect on the reliability of the ~~bulk power system~~Bulk Power System, *i.e.* an effect that can be measured using power system data or trends. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome.*

- **Risk-based ~~requirements~~Requirements** define actions ~~of~~by one or more entities that reduce a stated risk to the reliability of the ~~bulk power system~~Bulk Power System and can be measured by evaluating a particular product or outcome resulting from the required actions. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the Bulk Power System.*

- **Capability-based ~~requirements~~Requirements** define capabilities needed by one or more entities to perform reliability functions and can be measured by demonstrating that the capability exists as required. A capability-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the Bulk Power System.*

The body of reliability ~~requirements~~Requirements collectively provides a defense-in-depth strategy supporting reliability of the ~~bulk power system~~Bulk Power System.

2.5: Elements of a Reliability Standard

~~A reliability standard~~A Reliability Standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the ~~bulk power system. The components of a reliability standard include mandatory requirements, elements necessary to demonstrate compliance and monitor and assess compliance with requirements, and informational sections of the standard.~~Bulk Power System.

~~**Requirements and Elements Necessary to Demonstrate Compliance and Monitor and Assess Compliance with Requirements**~~

The components of a Reliability Standard may include the following:

Title: A brief, descriptive phrase identifying the topic of the ~~standard~~Reliability Standard.

Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the ~~standards.~~Reliability Standards.[4]

Rationale: Section 2.5 has been updated to reflect the SPIG recommendation that redundant elements of a standard be eliminated, as well as a recommendation that all standards developed be Results-based. To address the need for an alternate means to determine in a transparent manner the starting point for sanctions, a proposal for replacing VRFs and VSLs with '*Results-based Standards References*' is posted along with the proposed revisions to the SPM.

[4] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as provide on the Reliability Standards Resources web page.

Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

Applicability: Identifies which entities are assigned reliability requirements ~~of the standard.~~ . The specific Functional Entities and Facilities to which the Reliability Standard applies.

Effective Dates: Identification of the date or pre-conditions determining when each ~~requirement~~Requirement becomes effective in each jurisdiction.

Requirement: An explicit statement that identifies the ~~functional entity~~Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each ~~requirement~~Requirement shall be a statement for which compliance is mandatory.

~~***Measure:*** Provides identification of the evidence or types of evidence needed~~***Compliance Elements:*** Elements included in the standard to ~~demonstrate~~aid in the administration of ERO compliance ~~with the~~ monitoring and enforcement responsibilities.[5]

> ***Sanction Table Reference:*** Each Requirement in each Reliability Standard has an associated ~~requirement. Each requirement shall have~~Sanction Table reference. A Sanction Table reference is a Compliance Element developed by the drafting team, working with NERC staff, at ~~least one measure. Each measure shall clearly refer~~the same time as the associated Reliability Standard but not a part of the Reliability Standard. The term "Sanction Table" refers to ~~the requirement(s)~~Appendix 4B to ~~which it applies.~~the NERC Rules of Procedure, *Sanction Guidelines of the North American Electric Reliability Corporation* at Appendix A, Base Penalty Amount Table.

~~***Evidence Retention:*** Identification, for each requirement in the standard, of the entity that is responsible for retaining evidence to demonstrate compliance, and the duration for retention of that evidence.~~

Variance: A ~~requirement~~Requirement (to be applied in the place of the continent-wide ~~requirement), and its associated measure and compliance information,~~Requirement) that is applicable to a specific geographic area or to a specific set of ~~functional entities~~Registered Entities.

~~***Time Horizon:*** The time period an entity has to mitigate an instance of violating the associated requirement.[6]~~

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated ~~standard.~~Reliability Standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

~~***Compliance Monitoring and Assessment Processes:*** Identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated standard.~~

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[5] It is the responsibility of the ERO staff to develop compliance elements for each standard; these elements are not technically part of the standard but are included in the standard and referenced in this manual because the preferred approach to developing these elements is to use a transparent process that leverages the technical and practical expertise of the drafting team and ballot pool. If directed by FERC, NERC may file revisions to compliance elements following approval of the NERC Board of Trustees.

~~[6] The latest set of approved Time Horizon classifications is posted on the Reliability Standards Resources Web Page.~~

~~***Additional Compliance Information:*** Any other information related to assessing compliance such as the criteria or periodicity for filing specific reports.~~

~~***Violation Risk Factors and Violation Severity Levels:*** Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard[7]. Each requirement in each reliability standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC staff, at the same time as the associated reliability standard, but are not part of the reliability standard. The Board of Trustees is responsible for approving VRFs and VSLs.~~

~~***Violation Risk Factors***~~
~~VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria[8].~~

~~***Violation Severity Levels***~~
~~VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria[9].~~

~~Informational Sections of a Standard~~

***Application ~~Guidelines~~:guidelines*:** Guidelines to support the implementation of the associated ~~standard.~~Reliability Standard.

***Procedures*:** Procedures to support implementation of the associated ~~standard~~Reliability Standard.

The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

~~[7] The *Sanction Guidelines of the North American Electric Reliability Corporation* identifies the factors used to determine a penalty or sanction for violation of reliability standard and is posted on the NERC Web Site.~~
~~[8] The latest set of approved VRF Criteria is posted on the Reliability Standards Resources Web Page.~~
~~[9] The latest set of approved VSL Criteria is posted on the Reliability Standards Resources Web Page.~~

Section 3.0: Reliability Standards Program Organization

3.1: Board of Trustees

The NERC Board of Trustees shall consider for adoption ~~reliability standards~~Reliability Standards, definitions, ~~variances~~Variances and ~~interpretations~~Interpretations and associated implementation plans that have been processed according to the processes identified in this manual. ~~In addition, the board shall consider for approval, VRFs and VSLs associated with each approved standard.~~ Once the ~~board~~Board adopts a ~~reliability standard~~Reliability Standard, definition, ~~variance~~Variance or ~~interpretation, or once the board approves VRFs or VSLs, the board~~Interpretation, the Board shall direct NERC staff to file the document(s) for approval with applicable governmental authorities.

3.2: Registered Ballot Body

The Registered Ballot Body comprises all entities or individuals that qualify for one of the ~~stakeholder segments~~Segments approved by the Board of Trustees[10], and are registered with NERC as potential ballot participants in the voting on ~~standards.~~Reliability Standards. Each member of the Registered Ballot Body is eligible to join the ballot pool for each ~~standard~~Reliability Standard action.

3.3: Ballot Pool

Each ~~standard~~Reliability Standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot request to participate in that particular ~~standard~~Reliability Standard action. The ballot pool votes on each ~~standards~~Reliability Standards action. The ballot pool remains in place until all balloting related to that ~~standard~~Reliability Standard action has been completed.

3.4: Standards Committee

The Standards Committee serves at the pleasure and direction of the NERC Board of Trustees, and the ~~board~~Board approves the Standards Committee's Charter.[11] Standards Committee members are elected by their respective ~~segment's~~Segment's stakeholders. The Standards Committee consists of two members of each of the ~~stakeholder segments~~Segments in the Registered Ballot Body.[12] A member of the ~~standards~~NERC Reliability Standards staff shall serve as the ~~nonvoting~~non-voting secretary to the Standards Committee.

Changes were made throughout Section 3.0 to conform to changes in section 2.0 concerning the proposed elimination of VRFs/VSLs, and to reflect the alignment of standards requirements with RSAWs in response to SPIG Recommendation 4.

The Standards Committee is responsible for managing the ~~standards~~Reliability Standards processes for development of ~~standards, VRFs, VSLs~~Reliability Standards, definitions, ~~variances~~Variances and ~~interpretations~~Interpretations in accordance with this manual. The responsibilities of the Standards Committee are defined in detail in the Standards Committee's Charter. The Standards Committee is responsible for ensuring that the ~~standards, VRFs, VSLs~~Reliability Standards, definitions, ~~variances~~Variances and ~~interpretations~~Interpretations developed by drafting teams are developed in

[10] The ~~Industry~~industry Segment ~~Qualifications~~qualifications are described in the Development of the Registered Ballot Body and Segment Qualification Guidelines document posted on the Reliability Standards Resources ~~Web Page.~~web page and are included in Appendix 3D of the NERC Rules of Procedure.

[11] The Standards Committee Charter is posted on the Reliability Standards Resources ~~Web Page~~web page.

[12] In addition to balanced Segment representation, the Standards Committee shall also have representation that is balanced among countries based on Net Energy for Load ("NEL"). As needed, the Board of Trustees may approve special procedures for the balancing of representation among countries represented within NERC.

accordance with the processes in this manual and meet NERC's benchmarks for ~~reliability standards~~Reliability Standards as well as criteria for governmental approval[13]~~.~~.[14]

Text in redline version is accurate. Due to technical issues within this document, the redline does not accurately reflect footnote numbers. Footnote numbers are accurately reflected in the "clean" version of this document.

~~The Standards Committee has the right to remand work~~ to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team. The Standards Committee may disband a drafting team if it determines (a) that the drafting team is not producing a standard in a timely manner; (b) the drafting team is not able to produce a standard that will achieve industry consensus; (c) the drafting team has not addressed the scope of the SAR; or (d) the drafting team has failed to fully address a regulatory directive or otherwise provided a responsive or equally efficient and effective alternative. The Standards Committee may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for NERC's benchmarks for ~~reliability standards~~Reliability Standards, or to meet the criteria for governmental approval~~;~~ however~~,~~ the Standards Committee shall not direct a drafting team to change the technical content of a draft ~~standard.~~ Reliability Standard.

The Standards Committee shall meet at regularly scheduled intervals (either in person, or by other means). All Standards Committee meetings are open to all interested parties.

3.5: NERC Reliability Standards Staff

The ~~standards~~NERC Reliability Standards staff, led by the Director of Standards, is responsible for administering NERC's ~~reliability standards~~Reliability Standards processes in accordance with this manual. The ~~standards~~NERC Reliability Standards staff provides support to the Standards Committee in managing the ~~standards~~Reliability Standards processes and in supporting the work of all drafting teams. The ~~standards~~NERC Reliability Standards staff works to ensure the integrity of the ~~standards~~Reliability Standards processes and consistency of quality and completeness of the ~~reliability standards~~Reliability Standards. The ~~standards~~NERC Reliability Standards staff facilitates all steps in the development of ~~standards~~Reliability Standards, definitions, ~~variances, interpretations~~Variances, Interpretations and associated implementation plans. ~~The standards~~NERC staff ~~works~~develops RSAWs with the assistance of Reliability Standard drafting teams ~~in developing VRFs and VSLs for each standard~~as needed.

The ~~standards~~NERC Reliability Standards staff is responsible for presenting ~~standards~~Reliability Standards, definitions, ~~variances~~Variances, and ~~interpretations~~Interpretations to the NERC Board of Trustees for adoption. When presenting ~~standards~~Reliability Standards-related documents to the NERC Board of Trustees for adoption or approval, the ~~standards~~NERC Reliability Standards staff shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the document's practicality and enforceability.

3.6: Drafting Teams

The Standards Committee shall appoint industry experts to drafting teams to work with stakeholders in developing and refining Standard Authorization Requests ~~("~~("SARs~~), standards, VRFs, VSLs")~~, Reliability Standards, definitions, and ~~variances~~Variances. The ~~standards~~NERC Reliability Standards staff shall appoint drafting teams that develop ~~interpretations.~~ Interpretations. The NERC Reliability Standards staff shall provide, or solicit from the industry,

The proposed changes to drafting team composition are responsive to part of SPIG Recommendation 5, to "*Incorporate the support of technical writers, legal, compliance and rigorous and highly trained facilitation support.*"

Rationale for including drafting teams in development of compliance elements (including RSAws): RSAWs are a valuable tool used by both Compliance Auditors and Registered Entity personnel. When carefully drafted, an RSAW can serve as a source of information on the expectations of the requirements in the standard as well as a permanent record for information of how an entity demonstrated their compliance with a requirement. Including SDTs in work on RSAWs could minimize the need for CANs and formal interpretations of standards.

[13] ~~The Ten Benchmarks of an Excellent Reliability Standard and FERC's Criteria for Approving Reliability Standards are posted on the Reliability Standards Resources Web Page.~~

[14] The Ten Benchmarks of an Excellent Reliability Standard and FERC's Criteria for Approving Reliability Standards are posted on the Reliability Standards Resources web page.

essential support for each of the drafting teams in the form of technical writers, legal, compliance, and rigorous and highly trained facilitation support personnel.

Each drafting team ~~consists~~may consist of a group of technical, legal, and compliance experts that work cooperatively with the support of the ~~standards~~NERC Reliability Standards staff[15]~~.~~.[16] The technical experts provide the subject matter expertise and guide the development of the technical aspects of the ~~standard~~Reliability Standard, assisted by technical writers~~.~~, legal and compliance experts. The technical experts maintain authority over the technical details of the ~~standard.~~Reliability Standard. Each drafting team appointed to develop a ~~standard~~Reliability Standard is responsible for following the processes identified in this manual as well as procedures developed by the Standards Committee from the inception of the assigned project through the final acceptance of that project by applicable governmental authorities.

Collectively, each drafting team:

- Drafts proposed language for the ~~reliability standards~~Reliability Standards, definitions, ~~variances~~Variances, and/or ~~interpretations~~Interpretations and associated implementation plans.
- Develops and refines technical documents that aid in the understanding of Reliability Standards.
- Provides assistance to NERC staff in the development of compliance elements of proposed Reliability Standards.
- Solicits, considers, and responds to comments related to the specific ~~standards~~Reliability Standards development project.
- Participates in industry forums to help build consensus on the draft ~~reliability standards~~Reliability Standards, definitions, ~~variances~~Variances, and/or ~~interpretations~~Interpretations and associated implementation plans.
- Assists in developing the documentation used to obtain governmental approval of the ~~reliability standards~~Reliability Standards, definitions, ~~variances~~Variances, and/or ~~interpretations~~Interpretations and associated implementation plans.

All drafting teams report to the Standards Committee.

3.7: Governmental Authorities

The Federal Energy Regulatory Commission ~~(~~("FERC~~)~~") in the United States of America, and where permissible by statute or regulation, the provincial government of each of the eight Canadian Provinces (Manitoba, Nova Scotia, Saskatchewan, Alberta, Ontario, British Columbia, New Brunswick and Quebec) and the Canadian National Energy Board have the authority to approve each new, revised or withdrawn ~~reliability standard~~Reliability Standard, definition, ~~variance, interpretation, VRF~~Variance, and ~~VSL~~Interpretation following adoption or approval by the NERC Board of Trustees.

3.8: Committees, Subcommittees, Working Groups, and Task Forces

NERC's technical committees, subcommittees, working groups, and task forces provide technical research and analysis used to justify the development of new ~~standards~~Reliability Standards and provide guidance, when requested by the Standards Committee, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees, working groups, and task forces provide feedback to drafting teams during both informal and formal comment periods.

[15] ~~The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources Web Page.~~

[16] The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources web page.

The Standards Committee may request that a NERC technical committee or other group prepare a Technical document to support development of a proposed Reliability Standard.

The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified ~~standards~~Reliability Standards or ~~requirements~~Requirements with the ~~standards~~NERC Reliability Standards staff for use in identifying the need for new ~~standards~~Reliability Standards projects for the three-year *Reliability Standards Development Plan*.

3.9: Compliance and Certification Committee

The Compliance and Certification Committee is responsible for monitoring NERC's compliance with its ~~reliability standards~~Reliability Standards processes and procedures and for monitoring NERC's compliance with the Rules of Procedure regarding the development of new or revised ~~standards, VRFs, VSLs~~Reliability Standards, definitions, ~~variances~~Variances, and ~~interpretations.~~Interpretations. The Compliance and Certification Committee ~~assists~~may assist in verifying that each proposed ~~standard~~Reliability Standard is enforceable as written before the ~~standard~~Reliability Standard is posted for formal stakeholder comment and balloting.

3.10: Compliance Monitoring and Enforcement Program

The NERC ~~compliance enforcement program~~Compliance Monitoring and Enforcement Program Staff manages and enforces compliance with approved ~~reliability standards~~Reliability Standards. The ~~compliance enforcement program shall provide feedback to~~ drafting ~~teams~~team and the Compliance Monitoring and Enforcement Program staff shall work together during the ~~standards~~Reliability Standard development process to ensure ~~the compliance enforcement program can be practically implemented for~~ an accurate and consistent understanding of the ~~standards under development.~~

Requirements and their intent. The ~~compliance enforcement program may conduct field tests or data collection related~~goal of this collaboration is to ensure that application of the Reliability Standards in the Compliance Monitoring and Enforcement Program by NERC and the Regional Entities is consistent.

The Compliance Monitoring and Enforcement Program is encouraged to ~~compliance elements of proposed standards and may provide assistance with field tests or data collection when requested. The compliance enforcement program shares~~share its observations regarding the need for new or modified ~~requirements~~Requirements with the ~~standards~~NERC Reliability Standards staff for use in identifying the need for new ~~standards~~Reliability Standards projects.

Changes to Section 3.10 are intended to be responsive to SPIG Recommendation 4 and the following suggestion:
"Compliance staff will develop RSAWs (that will be used in the auditing of compliance) in conjunction and coincident with the development of the standard."

The intent is that drafting teams will work with NERC Compliance Monitoring and Enforcement Staff to develop compliance elements. Ultimately, compliance elements are the sole responsibility of NERC as the ERO. However, the technical expertise provided by drafting teams is a valuable resource to assist ERO staff in the drafting and development of compliance elements.

3.11: North American Energy Standards Board ~~(~~("NAESB~~)~~")

While NERC has responsibility for developing ~~standards~~Reliability Standards to support reliability, NAESB has responsibility for developing business practices and coordination between reliability and business practices ~~is~~as needed. ~~The~~ NERC and NAESB developed and approved a procedure[17] to guide the development of ~~reliability standards~~Reliability Standards and business practices where the reliability

[17] The NERC NAESB Template Procedure for Joint Standards Development and Coordination is posted on the Reliability Standards Resources ~~Web Page~~web page.

and business practice components are intricately entwined within a proposed ~~standard~~Reliability Standard.

Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard

There are several steps to the development, modification ~~or,~~ withdrawal or retirement of a ~~reliability standard~~[18] Reliability Standard.[19]

The development of the *Reliability Standards Development Plan* is the appropriate forum for reaching agreement on whether there is a need for a Reliability Standard and the scope of a proposed Reliability Standard. A typical process for a project identified in the *Reliability Standards Development Plan* that involves a revision to an existing ~~standard~~Reliability Standard is shown below. Note that most projects do not include a field test~~.~~

The proposed changes to the commenting and standard development processes in Section 4.0 are responsive to SPIG Recommendations 1 and 5 as well as the following suggestions:

- "Involve industry, NERC and FERC in the quality review earlier in the standards development process."
- "Modify the comment process to:
  - Bundle responses to comments."
- "Improve timeliness and effectiveness in terms of commenting/balloting (need to consider the manual effort and timing associated with posting, grouping and responding)"

Rationale: The comment process has been streamlined and revised to allow for summary responses to comments and only one formal comment period during which a drafting team is required to respond to comments in writing. In every case where written comments are accepted, the complete record of comments submitted will be posted as part of the development record of the standard.

If a drafting team determines that significant changes are needed as a result of a comment period, there is no formal obligation for a drafting team to respond to comments in writing. Rather, drafting teams may make any needed changes and communicate these changes via webinar or other informal methods. Drafting teams are mindful that in order to build consensus it is imperative to be responsive to comments, however, responding in writing to every single comment at every stage of standard development is time-intensive and can be inefficient. For this reason, the ability to provide informal feedback to stakeholders regarding how a team is responding to comments allows for necessary flexibility.

Following a substantive change, a proposal will again be posted for a 45 day comment period, accompanied by an explanation of the major changes proposed in the revised proposal. Once a drafting team has responded to comments in writing,

[18] ~~The process described is also applicable to projects used to propose a new or modified definition or variance or to propose retirement of a definition or variance.~~

[19] The process described is also applicable to projects used to propose a new or modified definition or Variance or to propose retirement of a definition or Variance.

~~Post~~.

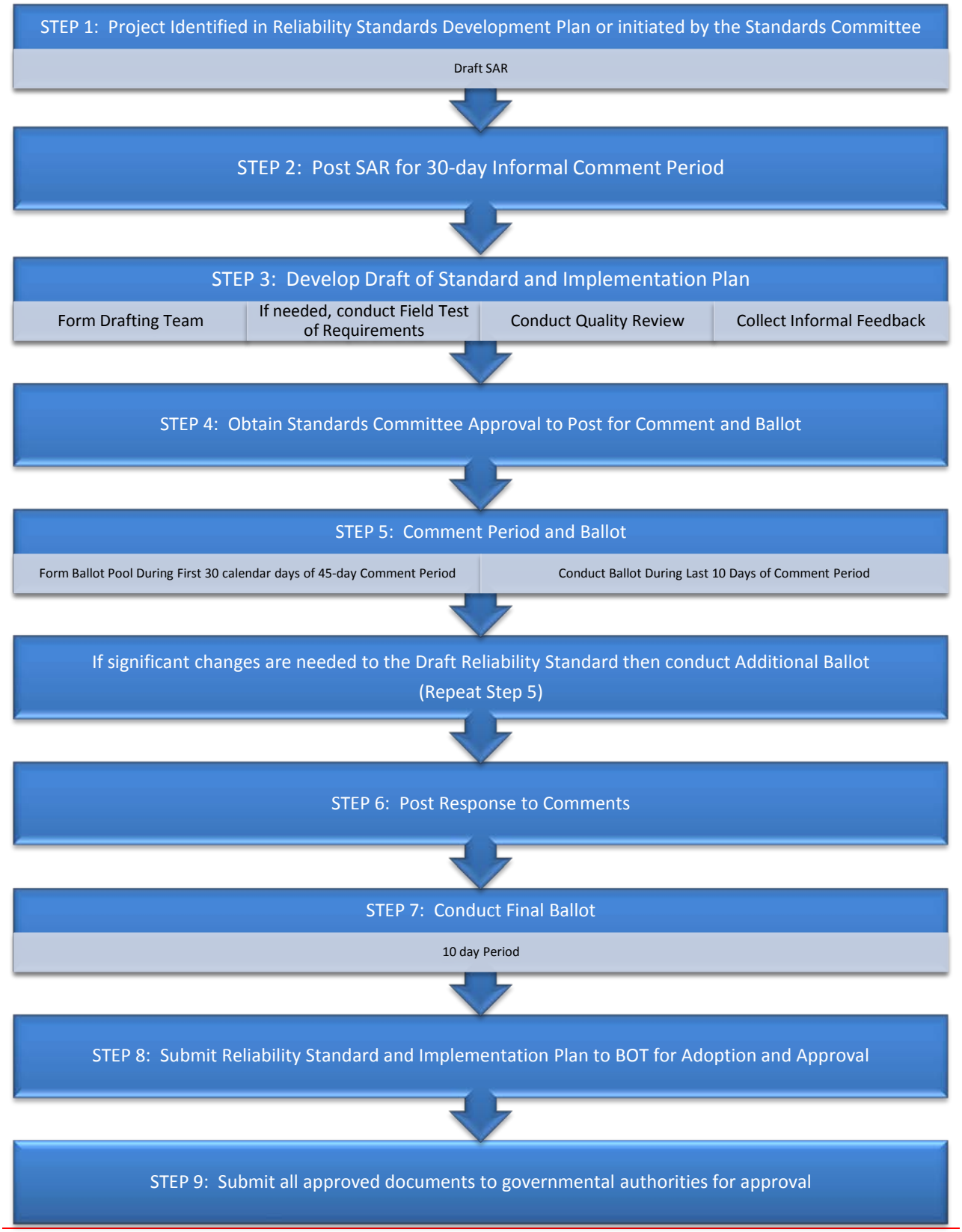


FIGURE 1: Process for Developing or Modifying a Reliability Standard

4.1: Posting and Collecting Information on SARs

SPIG Recommendation 2 recommends the formation of a Reliability Issues Steering Committee (RISC) to provide recommendations to the NERC Board of Trustees regarding the appropriate methods for addressing proposed reliability issues. As this recommendation is piloted, it is possible that some changes to the SAR process will be recommended but at this time no changes are proposed to the current process for handling SARs.

Standard Authorization Request

A Standard Authorization Request ~~(~~("SAR~~)~~") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified ~~standards.~~ Reliability Standards or the benefit of retiring one or more approved ~~standards.~~ Reliability Standards. Any entity or individual, including NERC committees or subgroups and NERC staff, may propose the development of a new or modified ~~standard~~Reliability Standard, or may propose the retirement of a ~~standard~~Reliability Standard, by submitting a completed SAR[20] to the ~~standards staff.~~

~~Most new standards projects will have been identified in the latest approved *Reliability Standards Development Plan*[21]. The initial SAR for these projects shall be drafted by NERC.~~ NERC Reliability Standards staff ~~and submitted to the Standards Committee with a request to post the SAR for stakeholder review.~~ The Standards Committee has the authority to approve the posting of all SARs for projects that propose developing a new or modified ~~standard~~Reliability Standard or propose retirement of an existing ~~standard~~Reliability Standard.

The ~~standards~~ NERC Reliability Standards staff sponsors an open solicitation period each year seeking ideas for new ~~standards~~Reliability Standards projects (using *Reliability Standards Suggestions and Comments forms*). The open solicitation period is held in conjunction with the annual revision to the *Reliability Standards Development Plan*. While the Standards Committee prefers that ideas for new projects be submitted during this annual solicitation period through submittal of a *Reliability Standards Suggestions and Comments Form*[22]~~,~~[23] a SAR proposing a specific project may be submitted to the ~~standards~~NERC Reliability Standards staff at any time.

Each SAR that proposes a "new" ~~standard,~~ or substantially revised Reliability Standard should be accompanied ~~with~~by a technical justification that includes, as a minimum, a discussion of the reliability-related ~~impact~~benefits and costs of ~~not~~ developing the new ~~standard~~Reliability Standard, and a technical foundation document (*e.g.*, research paper~~), when needed,~~) to guide the development of the ~~standard.~~

Reliability Standard. The ~~standards~~technical document should address the engineering, planning and operational basis for the proposed standard, as well as any alternative approaches considered during SAR development.

The NERC Reliability Standards staff shall review each SAR and work with the submitter to verify that all required information has been provided. All properly completed SARs shall be submitted to the Standards Committee for action at the next regularly scheduled Standards Committee meeting.

When presented with a SAR, the Standards Committee shall determine if the SAR is sufficiently ~~stated~~complete to guide ~~standard~~Reliability Standard development and whether the SAR is consistent with this manual. The Standards Committee shall take one of the following actions:

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[20] The SAR form can be downloaded from the Reliability Standards Resources ~~Web Page~~web page.

[21] ~~The latest approved version of the *Reliability Standards Development Plan* is posted on the Reliability Standards Resources Web Page.~~

[22] ~~The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources Web Page.~~

[23] The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources web page.

- Accept the SAR.
- Remand the SAR back to the ~~standards~~requestor or to NERC Reliability Standards staff for additional work.
- Reject the SAR. The Standards Committee may reject a SAR for good cause. If the Standards Committee rejects a SAR, it shall provide a written explanation for rejection to the sponsor within ten days of the rejection decision.
- Delay action on the SAR pending development of a technical justification for the proposed project.

~~If the Standards Committee remands, rejects, or delays action on a SAR, the sponsor may file an appeal following the appeals process provided in this manual.~~

If the Standards Committee is presented with a SAR that proposes developing a new ~~standard~~Reliability Standard but does not have a technical justification upon which the ~~standard~~Reliability Standard can be developed, the ~~committee~~ Standards Committee shall direct the ~~standards~~NERC Reliability Standards staff to post the SAR for a 30-day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the Standards Committee shall solicit assistance from NERC's technical committees or other industry experts ~~in providing~~to provide that foundation before authorizing development of the associated ~~standard~~Reliability Standard.

During the SAR comment process, the drafting team may become aware of potential regional Variances related to the proposed Reliability Standard. To the extent possible, any regional Variances or exceptions should be made a part of the SAR so that if the SAR is authorized, such variations shall be made a part of the draft new or revised Reliability Standard.

If the Standards Committee accepts a SAR, the project shall be added to the list of approved projects. The Standards Committee shall assign a priority to the project, relative to all other projects under development, and those projects already identified in the *Reliability Standards Development Plan* that are already approved for development.
The Standards Committee shall work with the ~~standards~~NERC Reliability Standards staff to coordinate the posting of SARs for new projects, giving consideration to each project's priority.

4.2: SAR Posting
When the Standards Committee determines it is ready to initiate a new project, the Standards Committee shall direct NERC staff to post the project's SAR in accordance with the following:

- For SARs that are limited to addressing regulatory directives, or revisions to ~~standards~~Reliability Standards that have had some vetting in the industry, authorize posting the SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments received.
- For SARs that address the development of new projects or ~~standards~~Reliability Standards, authorize posting the SAR for a 30-day formal comment period.

If a SAR for a new ~~standard~~Reliability Standard is posted for a formal comment period, the Standards Committee shall appoint a drafting team to work with the NERC staff coordinator ~~in giving~~to give prompt consideration ~~to~~of the written views and objections of all participants. The Standards Committee may use a public nomination process to populate the ~~standard~~Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. In some situations, an *ad hoc* team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to refine the

SAR and develop the ~~standard~~Reliability Standard, and additional members may not be needed. The drafting team shall ~~respond to~~address all comments submitted, which may be in the form of a summary response addressing each of the issues raised in comments received, during the public posting period. An effort to resolve all expressed objections shall be made, and each objector shall be advised of the disposition of the objection and the reasons therefore. ~~In addition, each objector shall be informed that an appeals procedure exists within the NERC standards process.~~ If the drafting team concludes that there ~~isn't~~is not sufficient stakeholder support to continue to refine the SAR, the team may recommend that the Standards Committee direct curtailment of work on the SAR.

While there is no established limit on the number of times a SAR may be posted for comment, the Standards Committee retains the right to reverse its prior decision and reject a SAR if it believes continued revisions are not productive. ~~Once again, the~~The Standards Committee shall notify the sponsor in writing of the rejection within ~~ten~~10 calendar days ~~and the sponsor may initiate an appeal using the appeals procedure~~.

~~During the SAR comment process, the drafting team may become aware of potential regional variances related to the proposed standard. To the extent possible, any regional variances or exceptions should be made a part of the SAR so that, if the SAR is authorized, such variations shall be made a part of the draft new or revised standard.~~

If stakeholders indicate support for the project proposed with the SAR, the drafting team shall present its work to the Standards Committee with a request that the Standards Committee authorize development of the associated ~~standard.~~Reliability Standard.

The Standards Committee, once again considering the public comments received and their resolution, may then take one of the following actions:

- Authorize drafting the proposed ~~standard~~Reliability Standard or revisions to a ~~standard~~Reliability Standard.
- Reject the SAR with a written explanation to the sponsor and post that explanation.

~~If the Standards Committee rejects a SAR, the sponsor may initiate an appeal.~~

4.3: Form Drafting Team

When the Standards Committee is ready to have a drafting team begin work on developing a new or revised ~~standard~~Reliability Standard, the Standards Committee shall appoint a drafting team, if one was not already appointed to develop the SAR. If the Standards Committee appointed a drafting team to refine the SAR, the same drafting team shall work to develop the associated ~~standard~~Reliability Standard.

If no drafting team is in place, then the Standards Committee may use a public nomination process to populate the ~~standard~~Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise, diversity of views and work process skills to ~~meet~~accomplish the objectives of the project~~.~~ on a timely basis. In some situations, an ad hoc team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to develop the ~~standard~~Reliability Standard, and additional members may not be needed.

The ~~standards~~NERC Reliability Standards staff shall provide ~~a member~~one or more members as needed to support the team with facilitation, project management, regulatory and technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project. ~~The~~ In developing the Reliability Standard, the individuals provided by the ~~standards~~NERC Reliability Standards staff serve as advisors to the drafting team and do not have voting rights~~. In~~

~~developing the standard, the~~ but share accountability along with the drafting team members assigned by the Standards Committee for timely delivery of a final draft Reliability Standard that meets the quality attributes identified in NERC's Benchmarks for Excellent Standards. The drafting team members assigned by the Standards Committee shall have final authority over the technical details of the ~~standard~~Reliability Standard, while the technical writer shall provide assistance to the drafting team in assuring that the final draft of the ~~standard~~Reliability Standard meets the quality attributes identified in NERC's Benchmarks for Excellent Standards.

Once it is appointed by the Standards Committee, the ~~standard~~Reliability Standard drafting team is responsible for making recommendations to the Standards Committee regarding the remaining steps in the ~~standards process. The~~Reliability Standards process. Consistent with the need to provide for timely standards development, the Standards Committee may decide a project is so large that it should be subdivided and either assigned to more than one drafting team or assigned to a single drafting team with clear direction on completing the project in specified phases. The normally expected timeframes for standards development within the context of this manual are applicable to individual standards and not to projects containing multiple standards. Alternatively, a single drafting team may address the entire project with a commensurate increase in the expected duration of the development work. If a SAR is subdivided and assigned to more than one drafting team, each drafting team will have a clearly defined portion of the work such that there are no overlaps and no gaps in the work to be accomplished~~.~~".

The Standards Committee may ~~also~~ supplement the membership of a ~~standard~~Reliability Standard drafting team ~~at any time~~or provide for additional advisors, as appropriate, to ensure the necessary competencies and diversity of views are maintained throughout the ~~standard~~Reliability Standard development effort.

4.4: Develop Preliminary Draft of Reliability Standard~~, and~~ Implementation Plan~~, VRFs and VSLs~~

4.4.1: Project Schedule

When a drafting team begins its work, either in refining a SAR or in developing or revising a proposed ~~standard~~Reliability Standard, the drafting team shall develop a project schedule ~~and~~ which shall be approved by the Standards Committee. The drafting team shall report progress~~,~~ to the Standards Committee, against ~~that~~the initial project schedule and any revised schedule as requested by the Standards Committee. Where project milestones cannot be completed on a timely basis, modifications to the project schedule must be presented to the Standards Committee for consideration along with proposed steps to minimize unplanned project delays.

4.4.2: Draft Reliability Standard

The team shall develop a ~~standard~~Reliability Standard that is within the scope of the associated SAR that includes all required elements as described earlier in this manual with a goal of meeting the quality attributes identified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval. The team shall document its justification for the ~~requirements~~Requirements in its proposed ~~standard~~ Reliability Standard by explaining how each meets these criteria. The standard drafting team shall identify the appropriate Sanction Table reference for each Requirement. The standard drafting team shall document its justification for selecting each reference by explaining how each Requirement fits the category chosen.

4.4.3: Implementation Plan

As a drafting team drafts its proposed revisions to a ~~reliability standard~~Reliability Standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated ~~standard~~Reliability Standard or ~~standards~~Standards. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the ~~requirements~~Requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated ~~standard~~Reliability Standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the ~~requirements~~Requirements.
- Whether approval of the proposed ~~standard~~Reliability Standard will necessitate any conforming changes to any already approved ~~standards~~Reliability Standards – and identification of those ~~standards~~Reliability Standards and ~~requirements~~Requirements.
- The ~~functional entities~~Functional Entities that will be required to comply with one or more ~~requirements~~Requirements in the proposed ~~standard~~Reliability Standard.

A single implementation plan may be used for more than one ~~standard~~Reliability Standard. The implementation plan is posted with the associated ~~standard~~Reliability Standard or ~~standards~~Standards during the 45~~-~~ (calendar) day formal comment period and is balloted with the associated ~~standard~~Reliability Standard.

~~**Violation Risk Factors and Violation Severity Levels**~~

~~The drafting team shall work with NERC staff in developing a set of VRFs and VSLs that meet the latest criteria established by NERC and governmental authorities. The drafting team shall document its justification for selecting each VRF and for setting each set of proposed VSLs by explaining how its proposed VRFs and VSLs meet these criteria. NERC staff is responsible for ensuring that the VRFs and VSLs proposed for stakeholder review meet these criteria.~~

Before the drafting team has finalized its ~~standard,~~ Reliability Standard, and implementation plan, ~~VRFs and VSLs,~~ the team should seek stakeholder feedback on its preliminary draft documents.

~~Solicit~~4.5: Informal Feedback[24]

Drafting teams may use a variety of methods to collect informal stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods,[25] webinars, industry meetings, workshops, or other mechanisms. ~~Informal comment periods, if used, shall have a minimum duration of 30 days.~~ Information gathered from informal comment forms shall be publicly posted ~~and, while~~. While drafting teams are not required to provide a written response to each individual comment received, drafting teams ~~must~~are encouraged, where possible, to post a summary response that identifies how it used comments submitted by stakeholders. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft."

Rationale: The 30 day informal comment period has been removed to provide more flexibility in the use of informal comment periods. This change is consistent with SPIG Recommendations 1 and 5. There is no ANSI requirement to have informal comment periods for 30 days.

4.6: Conduct Quality Review

The ~~standards~~NERC Reliability Standards staff shall coordinate a quality review[26] of the ~~"final draft" of the standard,~~ Reliability Standard, and implementation plan, ~~VRFs and VSLs~~in parallel with the development of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated SAR, whether the ~~standard~~Reliability Standard is clear and enforceable as written, and whether the ~~standard~~Reliability Standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of ~~standards, VRFs and VSLs. This review shall be completed within 30 days of receipt of the final version of the documents from the drafting team.~~Reliability Standards. The detailed results of this review shall be provided to the drafting team and the Standards Committee with a recommendation on whether the documents are ready for formal posting and balloting.

If the Standards Committee agrees that the proposed ~~standard,~~ Reliability Standard and implementation plan~~, VRFs or VSLs~~ pass

Rationale: The ability to conduct quality reviews in parallel with standard development is intended to add flexibility to the standard development process and reflects the fact that there may be a need to conduct multiple quality reviews as a standard continues to develop. One of our lessons learned is that conducting a quality review late in the drafting of a standard and providing this input to the team is inefficient for the team. The current process for conducting quality reviews adds a minimum of two to four weeks at every posting step. Drafting teams have requested that the quality review happen as they are drafting, rather than at the end before posting. By adding lawyers and compliance experts to work directly with drafting teams, much of what is covered in quality review should be addressed during drafting so that the review before posting is more of an administrative review – proofreading and checking for consistency and completeness – which will not require as much time.

[24] While this discussion focuses on collecting stakeholder feedback on proposed ~~standards,~~ Reliability Standards and implementation plans ~~and VRFs and VSLs~~, the same process is used to collect stakeholder feedback on proposed new or modified Interpretations, definitions and ~~variances~~Variances.

[25] The term "informal comment period" refers to a comment period conducted outside of the ballot process and where there is no requirement for a drafting team to respond in writing to submitted comments.

[26] The quality review will ~~involve a representative from~~be conducted in accordance with the ~~Compliance and Certification Committee as well as others; but will not involve individuals who participated in the development of the standard~~Standards Committee's approved procedure for conducting Quality Reviews.

this review, the Standards Committee shall authorize posting the proposed ~~standard,~~ Reliability Standard and implementation plan~~, VRFs and VSLs~~ for a formal comment period~~,~~ and ballot ~~(for the standard and implementation plan), and non-binding poll (for VRFs and VSLs)~~ as soon as the work flow will accommodate.

If the Standards Committee finds that any of the documents do not meet the specified criteria, the Standards Committee shall remand the documents to the drafting team for additional work.

If the ~~standard~~Reliability Standard is outside the scope of the associated SAR, the drafting team shall be directed to either revise the ~~standard~~Reliability Standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the ~~standard~~Reliability Standard is not clear and enforceable as written, or if the ~~standard or its VRFs or VSLs do~~Reliability Standard does not meet the specified criteria, the ~~standard~~Reliability Standard shall be returned to the drafting team by the Standards Committee with specific identification of any ~~requirement~~Requirement that is deemed to be unclear or unenforceable as written.

4.7: Conduct Formal Comment ~~Periods~~Period and Ballot

~~Most proposed~~Proposed new or modified ~~standards will~~ Reliability Standards require a ~~minimum of two~~ formal comment ~~periods~~period where the new or modified ~~standard, its associated VRFs and VSLs~~Reliability Standard, and implementation plan or the proposal to retire a ~~standard and its associated VRFs, VSLs~~Reliability Standard and implementation plan are posted. ~~The Standards Committee has the authority to waive the initial 30-day formal comment period if the proposed revision to a standard is minor and not substantive.~~

The ~~first~~ formal comment period shall be at least ~~30~~45-days long. ~~If the drafting team makes substantive revisions to the standard following the initial formal comment period, then the standard shall undergo another quality review before it is posted for its second formal comment period. The second formal comment period shall have a 45-day duration and shall start after the drafting team has posted its consideration of stakeholder comments and any conforming changes to the associated standard.~~

Formation of the ballot pool and ~~the initial ballot of the standard and the non-binding poll of the VRFs and VSLs~~Ballot of the Reliability Standard take place during ~~the second formal comment period. If additional formal comment periods are needed, they shall be at least 30-days in length and shall be conducted in parallel with successive ballots and if needed, successive non-binding polls of the VRFs and VSLs.~~

this formal 45-day comment period. The intent of the formal comment ~~periods~~period(s) is to solicit very specific feedback on the final draft of the ~~standard, VRFs, VSLs,~~Reliability Standard and implementation plan.

Comments in written form may be submitted on a draft Reliability Standard by any interested stakeholder, including NERC staff, FERC staff, and other interested governmental authorities. If stakeholders disagree with some aspect of the proposed set of products, comments provided should explain the reasons for such disagreement and, where possible, suggest specific language that would make the product acceptable to the stakeholder.

~~The drafting team shall consider and respond to all comments submitted during the formal comment periods at the same time and in the same manner as specified for addressing comments submitted with ballots. NERC staff shall provide assistance in responding to comments on VRFs and VSLs.~~

~~All comments received and all responses shall be publicly posted. Stakeholders who submit comments objecting to some aspect of the documents posted for comment shall determine if the response provided~~

by the drafting team satisfies the objection. All objectors shall be informed of the appeals process contained within this manual.

4.8: Form Ballot Pool

The standardsNERC Reliability Standards staff shall establish a ballot pool during the first 30 calendar days of the 45-day formal comment period. The standardsNERC Reliability Standards staff shall post the proposed standard, Reliability Standard, along with its implementation plan, VRFs, and VSLsSanction Table reference, and shall send a notice to every entity in the Registered Ballot Body to provide notice that there is a new or revised standardReliability Standard proposed for approval and to solicit participants for the associated ballot pool. All members of the Registered Ballot Body are eligible to join each ballot pool to vote on a new or revised reliability standard and its implementation plan. Members who join the ballot pool to vote on the new or revised standard and its implementation plan are automatically entered into the ballot pool to participate in the non-binding poll of the associated VRFs and VSLs. Reliability Standard and its implementation plan.

Any member of the Registered Ballot Body may join or withdraw from the ballot pool until the ballot window opens. No Registered Ballot Body member may join or withdraw from the ballot pool once the first ballot starts through the point in time where balloting for that standardReliability Standard action has ended. The Director of Standards may authorize deviations from this rule for extraordinary circumstances such as the death, retirement, or disability of a ballot pool member that would prevent an entity that had a member in the ballot pool from eligibility to cast a vote during the ballot window. Any approved deviation shall be documented and noted to the Standards Committee.

4.9: Conduct Initial Ballot and Conduct Non-binding Poll

The standardsNERC Reliability Standards staff shall announce the opening of the initial ballot window and the non-binding poll of VRFs and VSLs.Ballot window. The ballot window and non-binding pollBallot window shall both take place during the last 10 calendar days of the 45-day formal comment period. This allows all stakeholders the opportunity to comment and for the Final Ballot shall be no less than 10 calendar days. If the last day of the ballot window falls on the final draft of each proposed standard, even those stakeholders who are not members ofa Saturday, Sunday or federally-recognized United States holiday, the ballot poolperiod does not end until the next business day.

The ballot and non-binding poll shall be conducted electronically. The voting and polling windowswindow shall each be for a period of 10 calendar days but both shall be extended, if needed, until a quorum is achieved. During a ballot window, NERC shall not sponsor or facilitate public discussion of the standardReliability Standard action under ballot.

Consider and Respond to Stakeholder and Balloter Comments

The drafting team shall consider every stakeholder comment submitted either in response to a formal comment period or submitted with a ballot that includes a proposal for a specific modification to the standard or its implementation plan posted for comment and approval. The drafting team shall provide a response to each of these proposals indicating whether the drafting team adopted the recommendation, in accordance with the following:

If a Comment:	Then	And
Is unrelated to proposed standard action	Note that comment is unrelated	No further action needed
Proposes change that expands project scope	Note that comment is proposing an expansion	Add item to "issues database" for consideration during next update to the standard
Proposes a modification based on a technical issue not previously identified	Provide the drafting team's technical analysis of the proposal	If the team accepts the proposal, modify the standard
Proposed a modification based on a technical issue previously vetted	Provide a summary of the vetting and resolution previously reached	No further action needed
Proposes a modification to provide greater clarity	Provide the drafting team's view as to whether the proposed modification improves clarity	If the team accepts the proposal, modify the standard

If stakeholders submit comments that indicate a specific improvement to one or more of the VRFs or VSLs would improve consensus without violating the criteria for setting VRFs and VSLs, then the drafting team, working with NERC staff, shall consider and respond to each comment, and shall make conforming changes to reflect those comments. There is no requirement to conduct a new non-binding poll of the revised VRFs and VSLs if no changes were made to the associated standard, however if the requirements are modified and conforming changes are made to the associated VRFs and VSLs, another non-binding poll of the revised VRFs and VSLs shall be conducted.

All comments submitted and the responses to those comments shall be publicly posted.

4.10: Criteria for Ballot Pool Approval

Ballot pool approval of a reliability standardReliability Standard requires:

A quorum, which is established by at least 75% of the members of the ballot pool submitting a response with an affirmative vote, a negative vote, or an abstentionexcluding abstentions and non-responses; and

- A two-thirds majority of the weighted segmentSegment votes cast shall be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding with related comments. This calculation of votes for the purpose of determining consensus excludes (i) abstentions and, (ii) non-responses, (iii) negative votes without comments and (iv) negative votes with unrelated comments.

The following process[27] is used to determine if there are sufficient affirmative votes.

- For each segmentSegment with ten or more voters, the following process shall be used: The number of affirmative votes cast shall be divided by the sum of affirmative and negative votes cast to determine the fractional affirmative vote for that segmentSegment. Abstentions and, non-responses, negative votes without comments and negative votes with unrelated comments shall not be counted for the purposes of determining the fractional affirmative vote for a segmentSegment.

[27] Examples of Weighted Segment Voting Calculationweighted segment voting calculation are posted on the Reliability Standards Resources Web Pageweb page.

- For each ~~segment~~Segment with less than ten voters, the vote weight of that ~~segment~~Segment shall be proportionally reduced. Each voter within that ~~segment~~Segment voting affirmative or negative with related comment shall receive a weight of 10% of the ~~segment~~Segment vote.
- The sum of the fractional affirmative votes from all ~~segments~~Segments divided by the number of ~~segments~~Segments voting[28] shall be used to determine if a two-thirds majority has been achieved. (A ~~segment~~Segment shall be considered as "voting" if any member of the ~~segment~~Segment in the ballot pool casts either an affirmative or a negative vote.)
- A ~~standard~~ Reliability Standard shall be approved if the sum of fractional affirmative votes from all ~~segments~~Segments divided by the number of voting ~~segments~~Segments is at least two thirds.

4.11: Voting Positions

Each member of the ballot pool may **only** vote one of the following positions:

- Affirmative;
- Affirmative, with comment;
- ~~Negative without comment~~
- ~~Negative with comments (if possible reasons should include specific wording or actions that would resolve the objection)~~
- Negative with related comments. This includes clarifying comments or stated objections, comments of a procedural nature and comments concerning potential conflict or duplication of the draft Reliability Standard with an existing Reliability Standard. Comments should include guidance/input to the drafting team that would assist efforts that would make revisions to the Reliability Standard acceptable and enable an affirmative vote in a subsequent ballot;
- Abstain.

~~Each ballot~~Negative votes without comment shall not be counted for purposes of ballot pool approval, but shall be used in the calculation of quorum. If a member ~~submitting~~of the ballot pool submits a negative vote with comments ~~shall~~ that are not related to the proposal under consideration, such votes will be used in the calculation of quorum but not to determine ~~if the response provided~~ consensus.

If a drafting team determines that a negative ballot has been submitted without a comment or with a comment that is unrelated to the proposal under consideration, the drafting team must submit its finding in writing to the Standards Process Manager within 30 calendar days of the closing of the comment period. If this finding is affirmed by the ~~drafting team satisfies those stated concerns.~~NERC

Changes to Sections 4.11 respond to SPIG Recommendation 5 and the following suggestions: *"Limit negative ballots without comment" and "Ballot process shall:*
- *Use all votes cast by ballot pool member to establish quorum."*

ANSI was consulted and recommended that how negative votes would be treated be handled in an affirmative fashion. This suggestion was adopted in the language indicating what types of voting positions are accepted.

Rationale: Negative votes submitted without comments are inconsistent with NERC's consensus building process and provide no input to drafting teams as to how to revise their work to achieve a consensus standard.

The requirement to submit related comments with a negative vote is intended to encourage the submission of comments that will provide guidance to drafting teams.

[28] When less than ten entities vote in a ~~segment~~Segment, the total weight for that ~~segment~~Segment shall be determined as one tenth per entity voting, up to ten.

Legal department, the Standards Process Manager will then provide the balloter an opportunity to provide additional comments. If the balloter does not provide related comments within 10 business days, the ballot results will be recalculated without the negative ballot. Each such balloter shall be informed of the appeals process contained within this manual. Where the outcome of the ballot result is affected by a negative ballot that is the subject of an appeal, the ballot results will not be considered final until the appeal is resolved pursuant to this manual.

If a ~~standard~~Reliability Standard achieves a quorum~~ and~~, there are no negative votes with clarifying comments or stated objections from the ~~initial~~ ballot, and the overall approval is at least two thirds (weighted by ~~segment)~~Segment), then the results of the ~~initial~~ ballot shall stand as final, and the draft ~~reliability standard~~Reliability Standard and associated implementation plan shall be deemed to be approved by its ballot pool.

~~**Successive Ballots (Standard has Changed Substantively from Prior Ballot)**~~

4.12: Additional Ballots

If a stakeholder or balloter proposes a significant revision to the ~~standard~~Reliability Standard during the formal comment period or concurrent ~~initial ballot~~ Ballot that will improve the quality, clarity, or enforceability of that ~~standard~~Reliability Standard, then the drafting team ~~shall~~may choose to make such revisions and post the revised ~~standard~~Reliability Standard for another 45 calendar day public comment period and ballot. ~~If~~ Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond to comments in writing to the previous ballot ~~achieved~~but will respond to comments prior to conducting a ~~quorum~~Final Ballot.

4.13: Consideration of Comments

A drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and ~~sufficient affirmative ballots for approval, the~~ an additional ballot will be conducted. However, a drafting team must respond in writing to every stakeholder comment ~~period~~submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be ~~30 days and the new ballot may focus on the entire standard and its implementation plan or may focus only on the element(s) that were changed following the previous ballot.~~publicly posted.

~~The drafting team shall address comments submitted during successive ballot periods (comments submitted from stakeholders during the open formal comment period and comments submitted with negative ballots) in the same manner as for the initial ballot. Once the drafting team has a draft standard that has been through a "successive ballot" and the team believes that no additional significant modifications are needed, the standard shall be posted for a Recirculation Ballot.~~

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.14: Conduct ~~Recirculation (~~Final~~)~~ Ballot

~~**(Standard has not Changed Substantively from Prior Ballot)**~~

When the drafting team has reached a point where it has made a good faith effort at resolving applicable objections~~, the team shall conduct a recirculation ballot. In the recirculation ballot, members of the ballot pool shall again be presented the proposed standard (that has not been significantly changed from the~~

~~previous ballot) along with the reasons for negative votes, the responses, and any resolution of the differences.~~ and is not making any significant changes from the previous ballot, the team shall conduct a "Final Ballot." An insignificant revision is a revision that does not change the scope, applicability, or intent of any ~~requirement~~Requirement and includes but is not limited to things such as correcting the numbering of a ~~requirement~~Requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a ~~requirement~~Requirement for improved clarity. Where there is a question as to whether a proposed modification is "substantive~~"~~," the Standards Committee shall make the final determination. ~~There is no formal comment period concurrent with the recirculation ballot and no obligation for the drafting team to respond to any comments submitted during the recirculation ballot.~~

In the Final Ballot, members of the ballot pool shall again be presented the proposed Reliability Standard along with the reasons for negative votes from the previous ballot, the responses of the drafting team to those concerns, and any resolution of the differences.

All members of the ballot pool shall be permitted to reconsider and change their vote from the prior ballot. Members of the ballot pool who did not respond to the prior ballot shall be permitted to vote in the ~~recirculation ballot.~~Final Ballot. In the ~~recirculation ballot~~Final Ballot, votes shall be counted by exception only — members on the ~~recirculation ballot~~Final Ballot may indicate a revision to their original vote; otherwise their vote shall remain the same as in their prior ballot.

4.15: Final Ballot Results

There are no limits to the number of ~~"successive"~~ public comment periods and ballots that can be conducted to result in a ~~standard~~Reliability Standard or interpretation that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval. The Standards Committee has the authority to conclude this process ~~or~~for a particular ~~standards~~Reliability Standards action if it becomes obvious that the drafting team cannot develop a ~~standard~~Reliability Standard that is within the scope of the associated SAR, is sufficiently clear to be enforceable, and achieves the requisite weighted ~~segment~~Segment approval percentage.

The ~~standards~~ NERC Reliability Standards staff shall post the final outcome of the ballot process. If the ~~standard~~Reliability Standard is rejected, the ~~process is ended and any~~ Standards Committee may decide whether to end all further work on the ~~items within~~proposed standard, return the ~~SAR's original scope shall require a new SAR~~project to informal development, or continue holding ballots to attempt to reach consensus on the proposed standard. If the ~~standard~~Reliability Standard is approved, the ~~consensus standard~~Reliability Standard shall be posted and presented to the Board of Trustees by NERC management for adoption ~~by NERC~~and subsequently filed with applicable governmental authorities for approval.

4.16: Board of Trustee Adoption of Reliability Standards and Implementation Plans

~~A reliability standard and its implementation plan submitted for adoption by the Board of Trustees shall be provided to the NERC Board of Trustees at the same time it is posted for the ballot pool's pre-ballot review.~~ If ~~the standard~~a Reliability Standard and its associated implementation plan are approved by ~~their~~its ballot pool, the Board of Trustees shall consider adoption of that ~~reliability standard~~ Reliability Standard and its associated implementation plan and shall direct the standard to be filed with applicable governmental authorities for approval. In making its decision, the ~~board~~Board shall consider the results of the balloting and unresolved dissenting opinions. The ~~board~~Board shall adopt or reject a ~~standard~~Reliability Standard and its implementation plan, but shall not modify a proposed ~~reliability standard~~Reliability Standard. If the ~~board~~Board chooses not to adopt a ~~standard~~Reliability Standard, it shall provide its reasons for not doing so.

~~Board of Trustee Approval of Violation Risk Factors and Violation Severity Levels~~

~~The board shall consider approval of the VRFs and VSLs associated with a reliability standard. In making its determination, the board shall consider the following:~~

- ~~The Standards Committee shall present the results of the non-binding poll conducted and a summary of industry comments received on the final posting of the proposed VRFs and VSLs.~~
- ~~NERC staff shall present a set of recommended VRFs and VSLs that considers the views of the standard drafting team, stakeholder comments received on the draft VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.~~

~~Governmental Approvals~~

~~If the board approves a reliability standard and its implementation plan and the associated VRFs and VSLs, the board shall direct NERC staff to file the standard, its implementation plan and its associated VRFs and VSLs, with applicable governmental authorities in the United States, Canada, and Mexico for approval.~~

4.17: Compliance

For a ~~standard~~Reliability Standard to be enforceable, it shall be approved by its ballot pool, adopted by the NERC Board of Trustees, and ~~then~~ approved by applicable governmental authorities. Once a ~~reliability standard~~Reliability Standard is approved or otherwise made mandatory by applicable governmental authorities ~~in the United States, Canada, and Mexico~~, all persons and organizations subject to ~~the reliability~~ jurisdiction ~~are~~of the ERO will be required to comply with the ~~standard~~Reliability Standard in accordance with applicable statutes, regulations, and agreements.

4.18: Withdrawal of a Reliability Standard, Interpretation, or Definition

The term "withdrawal" as used herein, refers to the discontinuation of a Reliability Standard, Interpretation, Variance or definition that has been approved by the Board of Trustees and (1) has not been filed with FERC, or (2) has been filed with, but not yet approved by, FERC. The Standards Committee may withdraw a Reliability Standard, Interpretation or definition for good cause upon approval by the Board of Trustees. Upon approval by the Board of Trustees, NERC staff will petition the applicable governmental authorities to allow for withdrawal.

4.19: Retirement of a Reliability Standard, Interpretation, or Definition

The term "retirement" refers to the discontinuation of a Reliability Standard, Interpretation or definition that has been approved by FERC. A Reliability Standard, Variance or definition may be retired when it is superseded by a revised version, and in such cases the retirement of the earlier version is to be noted in the implementation plan presented to the ballot pool for approval and the retirement shall be considered approved by the ballot pool upon ballot pool approval of the revised version.

Upon identification of a need to retire a Reliability Standard, Variance, Interpretation or definition by the Standards Committee or NERC staff, where the item will not be superseded by a new or revised version, a SAR containing the proposal to retire a Reliability Standard, Interpretation or definition will be posted for a comment period and ballot in the same manner as a Reliability Standard. The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Power System. Upon approval by the Board of Trustees, NERC staff will petition the applicable governmental authorities to allow for retirement.

Rationale: Sections 4.18 and 4.19 have been incorporated to specifically to address withdrawal or retirement of Reliability Standards, Interpretations, Definitions or Variances in order to provide clarity as to the procedures that apply to such circumstances. The process described is intended to match the current practice.

Section 5.0: Process for Developing a Defined Term

No substantive changes have been made to Section 5.0.

NERC maintains a glossary of approved terms, entitled the "*Glossary of Terms Used in NERC Reliability Standards*."[29][30] ("Glossary of Terms"). The glossaryGlossary of Terms includes terms that have been through the formal approval process and are used in one or more NERC reliability standardsReliability Standards. Definitions shall not contain statements of performance requirements. There are two sections to the glossary. The first section includes definitions for terms used in continent-wide standards, and the second section includes definitions for terms used in Regional Entity standards that have been adopted by the NERC Board of Trustees.Requirements. The Glossary of Terms is intended to provide consistency throughout the Reliability Standards.

There are several methods that can be used to add, modify or retire a defined term used in a continent-wide standardReliability Standard.

- Anyone can use a Standard Authorization Request ((("SAR)")) to submit a request to add, modify, or retire a defined term.
- Anyone can submit a Standards Comments and Suggestions Form recommending the addition, modification, or retirement of a defined term. (The suggestion would be added to a project and incorporated into a SAR.)
- A drafting team may propose to add, modify, or retire a defined term in conjunction with the work it is already performing.

5.1: Proposals to Develop a New or Revised Definition

The following considerations should be made when considering proposals for new or revised definitions:

- Some NERC Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by a RegionRegional Entity, the same definition should be adopted if needed to support a NERC standardReliability Standard.
- If a term is used in a reliability standardReliability Standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the NERC Glossary of Terms *Used in Reliability Standards*.
- If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved standardsReliability Standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved standardsReliability Standards.
- When practical, where The North American Energy Standards Board (NAESB) has a definition for a term, the drafting team shall use the same definition to support a NERC standardReliability Standard.

[29] The latest approved version of the glossary is posted on the Standards Web Page.
[30] The latest approved version of the Glossary of Terms is posted on the NERC website on the Standards web page.

Any definition that is balloted separately from a proposed new or modified ~~standard~~Reliability Standard or from a proposal for retirement of a ~~standard~~Reliability Standard shall be accompanied by an implementation plan.

If a SAR is submitted to the ~~standards~~NERC Reliability Standards staff with a proposal for a new or revised definition, the Standards Committee shall consider the urgency of developing the new or revised definition and may direct NERC staff to post the SAR immediately, or may defer posting the SAR until a later time based on its priority relative to other projects already underway or already approved for future development. If the SAR identifies a term that is used in a ~~standard~~Reliability Standard already under revision by a drafting team, the Standards Committee may direct the drafting team to add the term to the scope of the existing project. Each time the Standards Committee accepts a SAR for a project that was not identified in the *Reliability Standards Development Plan*, the project shall be added to the list of approved projects.

5.2: Stakeholder Comments and Approvals

Any proposal for a new or revised definition shall be processed in the same manner as a ~~standard.~~Reliability Standard. The drafting team shall submit its work for a quality review and the Standards Committee and drafting team shall consider that review when determining whether the definition and its implementation plan are ready for formal comment and balloting. Once authorized by the Standards Committee, the proposed definition and its implementation plan shall be posted for at least one ~~45-day~~ formal stakeholder comment period and shall be balloted in the same manner as a ~~standard~~Reliability Standard. If a new or revised definition is proposed by a drafting team, that definition may be balloted separately from the associated ~~standard~~Reliability Standard.

Each definition that is approved by its ballot pool shall be submitted to the NERC Board of Trustees for adoption and then filed with applicable governmental authorities for approval in the same manner as a ~~standard~~Reliability Standard.

~~Process for Developing a New or Revised Definition Initiated with a SAR~~

Section 6.0: Processes for Conducting Field Tests and Collecting and Analyzing Data

No substantive changes have been made to Section 6.0.

While most drafting teams can develop their ~~standards~~Reliability Standards without the need to conduct any field tests and without the need to collect and analyze data, some ~~standard~~Reliability Standard development efforts may ~~involve~~require field tests ~~analysis of~~to analyze data ~~to~~and validate concepts~~, requirements or compliance elements of standards~~ in the development of Reliability Standards.

There are ~~three~~two types of field tests – tests of concepts~~; tests of requirements;~~ and tests of ~~compliance elements~~requirements.

6.1: Field Tests and Data Analysis for Validation of Concepts

Field tests or collection and analysis of data to validate concepts that support the development of ~~requirements~~Requirements should be conducted before the SAR for a project is finalized. If an entity wants to test a technical concept in support of a proposal for a new or revised ~~reliability standard~~Reliability Standard, the entity should either work with one of NERC's technical committees in collecting and analyzing the data or in conducting the field test, or the entity should submit a SAR with a request to collect and analyze data or conduct a field test to validate the concept prior to developing a new or revised ~~standard.~~Reliability Standard. The request to collect and analyze data or conduct a field test should include, at a minimum, either the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the analysis of the results. If the SAR sponsor has not collected and analyzed the data or conducted the field test, the Standards Committee may solicit support from NERC's technical committees or others in the industry. The results of the data collection and analysis or field test shall then be used to determine whether to add the SAR to the list of projects in the Reliability Standard Development Plan.

If a drafting team finds that it needs to collect and analyze data or conduct a field test of a concept that was not identified when the SAR was accepted, then the Standards Committee may direct the team to withdraw the SAR until the data has been collected and analyzed or until the field test has been conducted and the industry has had an opportunity to review the results for the impact on the scope of the proposed project.

6.2: Field Tests and Data Analysis for Validation of Requirements

If a drafting team wants to conduct a field test or collect and analyze data to validate its proposed ~~requirements, measures, or compliance elements~~Requirements in a ~~reliability standard~~Reliability Standard, the team shall first obtain approval from the Standards Committee[31]~~.~~[32] Drafting teams are not required to collect and analyze data or to conduct a field test to validate a ~~standard.~~Reliability Standard.

The request should include at a minimum the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the results. When authorizing a

[31] ~~The Process for Approving Data Collection and Analysis and Field Tests Associated with a Reliability Standard is posted on the Reliability Standards Resources Web Page.~~

[32] The Process for Approving Data Collection and Analysis and Field Tests Associated with a Reliability Standard is posted on the Reliability Standards Resources web page.

drafting team to collect and analyze data or to conduct a field test of one or more ~~requirements~~Requirements, the Standards Committee may request inputs on technical matters related from NERC's technical committees or industry experts, and may request the assistance of the ~~compliance organization.~~Compliance Monitoring and Enforcement Program. All data collection and analysis and all field tests shall be concluded and the results incorporated into the ~~standard requirements~~Reliability Standard Requirements as necessary before proceeding to the formal comment period and subsequent balloting.

~~**Field Tests and Data Analysis for Validation of Compliance Elements**~~

~~If the Compliance Monitoring and Enforcement Program identifies a need to collect and analyze data or conduct a field test of one or more of the compliance elements of a proposed standard, then the Compliance Monitoring and Enforcement Program shall request the Standards Committee's approval. The request should include at a minimum the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the results.~~

~~When authorizing a drafting team to collect and analyze data or to conduct a field test of one or more compliance elements of a standard, the Standards Committee shall request the assistance of the Compliance Monitoring and Enforcement Program in conducting the field test.~~

6.3: Communication and Coordination for All Types of Field Tests and Data Analyses

If the conduct of a field test (concepts~~, requirements or compliance elements~~ or Requirements) or data collection and analysis could render Registered Entities incapable of complying with the current ~~requirements~~Requirements of an approved ~~standard~~Reliability Standard that is undergoing revision, the drafting team shall request a temporary waiver from compliance to those ~~requirements~~Requirements for entities participating in the field test. Upon request, the Standards Committee shall seek approval for the waiver from the Compliance Monitoring and Enforcement Program prior to the approval of the field test or data collection and analysis.

Once a plan for a field test or a plan for data collection and analysis is approved, the ~~standards~~NERC Reliability Standards staff shall, under the direction of the Standards Committee, coordinate the implementation of the field test or data collection and analysis and shall provide official notice to the participants in the field test or data collection of any applicable temporary waiver to compliance with specific noted ~~requirements~~Requirements. The drafting team conducting the field test shall provide periodic updates on the progress of the field tests or data collection and analysis to the Standards Committee. The Standards Committee has the right to curtail a field test or data collection and analysis that is not implemented in accordance with the approved plan.

The field test plan or data collection and analysis plan, its approval, its participants, and all reports and results shall be publicly posted for stakeholder review on the Reliability Standards ~~Web Page~~web page.

If a drafting team conducts or participates in a field test or in data collection and analysis (of concepts~~, requirements or compliance elements~~ or Requirements), it shall provide a final report that identifies the results and how those results will be used.

Section 7.0: Process for Developing an Interpretation

Changes to Section 7.0 are intended to clarify the basis and process for rejecting an interpretation, consistent with guidance issued by the NERC Board of Trustees in November 2009, and to incorporate some of the elements of the Standards Committee's Guidelines to Interpretation Drafting teams.

A valid ~~interpretation~~ Interpretation request is one that requests additional clarity about one or more ~~requirements~~Requirements in approved NERC ~~reliability standards~~Reliability Standards, but does not request approval as to how to comply with one or more ~~requirements~~Requirements. A valid ~~interpretation~~Interpretation response provides additional clarity about one or more ~~requirements~~Requirements, but does not expand on any ~~requirement~~Requirement and does not explain how to comply with any ~~requirement~~Requirement. Any entity that is directly and materially affected by the reliability of the North American ~~bulk power systems~~Bulk Power Systems may request an ~~interpretation~~Interpretation of any ~~requirement~~Requirement in any continent-wide ~~standard~~Reliability Standard that has been adopted by the NERC Board of Trustees. Interpretations will only be provided for Board of Trustees-approved Reliability Standards *i.e.* (i) the current effective version of a Reliability Standard; or (ii) a version of a Reliability Standard with a future effective date.

An Interpretation may only clarify or interpret the Requirements of an approved Reliability Standard, including, if applicable, any attachment referenced in the Requirement being clarified. No other elements of an approved Reliability Standard are subject to Interpretation.

The entity requesting the ~~interpretation~~Interpretation shall submit a *Request for Interpretation* form[33] to the ~~standards~~NERC Reliability Standards staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the ~~interpretation provided.~~Interpretation provided. The NERC Reliability Standards and Legal staffs shall review the request for interpretation to determine whether it meets the requirements for a valid interpretation. Based on this review, the NERC Standards and Legal staffs shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

~~The standards~~
For example, an Interpretation request may be rejected where it:

(1) Requests approval of a particular compliance approach;
(2) Identifies a gap or perceived weakness in the approved Reliability Standard;
(3) Where an issue can be addressed by an active standard drafting team;
(4) Where it requests clarification of any element of a Reliability Standard other than a Requirement;
(5) Where a question has already been addressed in the record;
(6) Where the Interpretation identifies an issue and proposes the development of a new or modified Reliability Standard, (such issues should be addressed via submission of a SAR);
(7) Where an Interpretation seeks to expand the scope of a Reliability Standard; or
(8) Where the meaning of a Reliability Standard is plain on its face.

[33] The *Request for Interpretation* ~~Form~~form is posted on the NERC Standards ~~Web Page~~web page.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the Interpretation within 10 business days of the decision to reject. If the Standards Committee accepts the Interpretation request, the NERC Standards staff shall form a ballot pool and assemble an ~~interpretation~~Interpretation drafting team with the relevant expertise to address the ~~clarification~~interpretation. As soon as practical, the team shall develop a "final draft" ~~interpretation~~Interpretation providing the requested clarity.

~~The standards staff shall coordinate a quality review[34] of the interpretation to assess whether the interpretation is clear and provides the requested clarity without expanding on any requirement. The detailed results of this review shall be provided to the drafting team and the Standards Committee with a recommendation on whether the documents are ready for formal posting and balloting and if the Standards Committee agrees that the proposed interpretation passes this review, the Standards Committee shall authorize posting the proposed interpretation.~~

~~The first formal comment period shall be 30 days long. If the drafting team makes substantive revisions to the interpretation following the initial formal comment period, then the interpretation shall undergo another quality review before it is posted for its second formal comment period. The second formal comment period shall have a 45-day duration and shall start after the drafting team has posted its consideration of stakeholder comments and any conforming changes to the associated standard.~~

~~Formation of a ballot pool shall take place during the first 30 days of the 45-day formal comment period, and the initial ballot of the interpretation shall take place during the last 10 days of that formal comment period. The interpretation drafting team shall consider and respond to all comments submitted during the formal comment period at the same time and in the same manner as specified for addressing comments submitted with ballots.~~

~~All comments received and all responses shall be publicly posted. Stakeholders who submit comments objecting to some aspect of the interpretation shall determine if the response provided by the drafting team satisfies the objection. All objectors shall be informed of the appeals process contained within this manual.~~

- ~~If the ballot achieves a quorum and a 2/3 weighted segment approval, and there are no negative ballots with comments the ballot results are final.~~
- ~~If stakeholder comments indicate the need for minor revisions, the interpretation drafting team shall make those revisions and post the interpretation for a 10-day recirculation ballot. (A minor revision is a revision that includes but is not limited to things such as correcting the spelling of a word, adding an obviously missing word, or rephrasing a sentence for improved clarity without changing the scope of what was previously written.) If stakeholder comments indicate that there is not consensus for the interpretation or if stakeholders propose significant modifications that would improve the interpretation and the interpretation drafting team can revise the interpretation without violating the basic expectations outlined above, the interpretation drafting team shall post the comments received and a revised interpretation for a 30-day comment period and balloting during the last 10 days of that comment period. If the ballot achieves a quorum and a 2/3 weighted segment approval, and additional modifications to the interpretation are not necessary (based on a review of the comments submitted with the ballot) the interpretation shall proceed to a recirculation ballot.~~

~~If stakeholder comments indicate that there is not consensus for the interpretation, and the interpretation drafting team cannot revise the interpretation without violating the basic expectations outlined above, the interpretation~~

~~[34] The quality review will involve a representative from the Compliance and Certification Committee as well as others; but will not involve individuals who participated in the development of the interpretation.~~

Interpretations will be balloted in the same manner as Reliability Standards.

If stakeholder comments indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic expectations outlined above, the Interpretation drafting team shall notify the Standards Committee of its conclusion and shall submit a SAR with the proposed modification to the ~~standard.~~Reliability Standard. The entity that requested the ~~interpretation~~Interpretation shall be notified and the disposition of the ~~interpretation~~Interpretation shall be posted.

If, during its deliberations, the ~~interpretation~~Interpretation drafting team identifies a reliability gap in the ~~standard~~Reliability Standard that is highlighted by the ~~interpretation~~Interpretation request, the ~~interpretation~~Interpretation drafting team shall notify the Standards Committee of its conclusion and shall submit a SAR with the proposed modification to the ~~standard~~Reliability Standard at the same time it provides its proposed ~~interpretation, recommending use of the expedited standards development process as appropriate to address any significant reliability gap~~Interpretation.

The NERC Reliability Standards and Legal staffs shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Standards and Legal staffs shall make a recommendation to the NERC Board of Trustees regarding adoption.

If approved by its ballot pool, the ~~interpretation~~Interpretation shall be ~~appended to the standard and~~ forwarded to the NERC Board of Trustees for adoption.[35] If an ~~interpretation~~Interpretation drafting team proposes a modification to a ~~standard~~Reliability Standard as part of its work in developing an ~~interpretation~~Interpretation, the Board of Trustees shall be notified of this proposal at the time the ~~interpretation~~Interpretation is submitted for adoption. Following adoption by the Board of Trustees, NERC staff shall file the ~~interpretation~~Interpretation for approval by applicable governmental authorities and the ~~interpretation~~Interpretation shall become effective when approved by those applicable governmental authorities. The ~~interpretation~~Interpretation shall stand until such time as the ~~interpretation~~Interpretation can be incorporated into a future revision of the ~~standard~~Reliability Standard or the ~~interpretation~~Interpretation is retired due to a future modification of the applicable ~~requirement~~Requirement.

[35] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.

~~Processing a Request~~

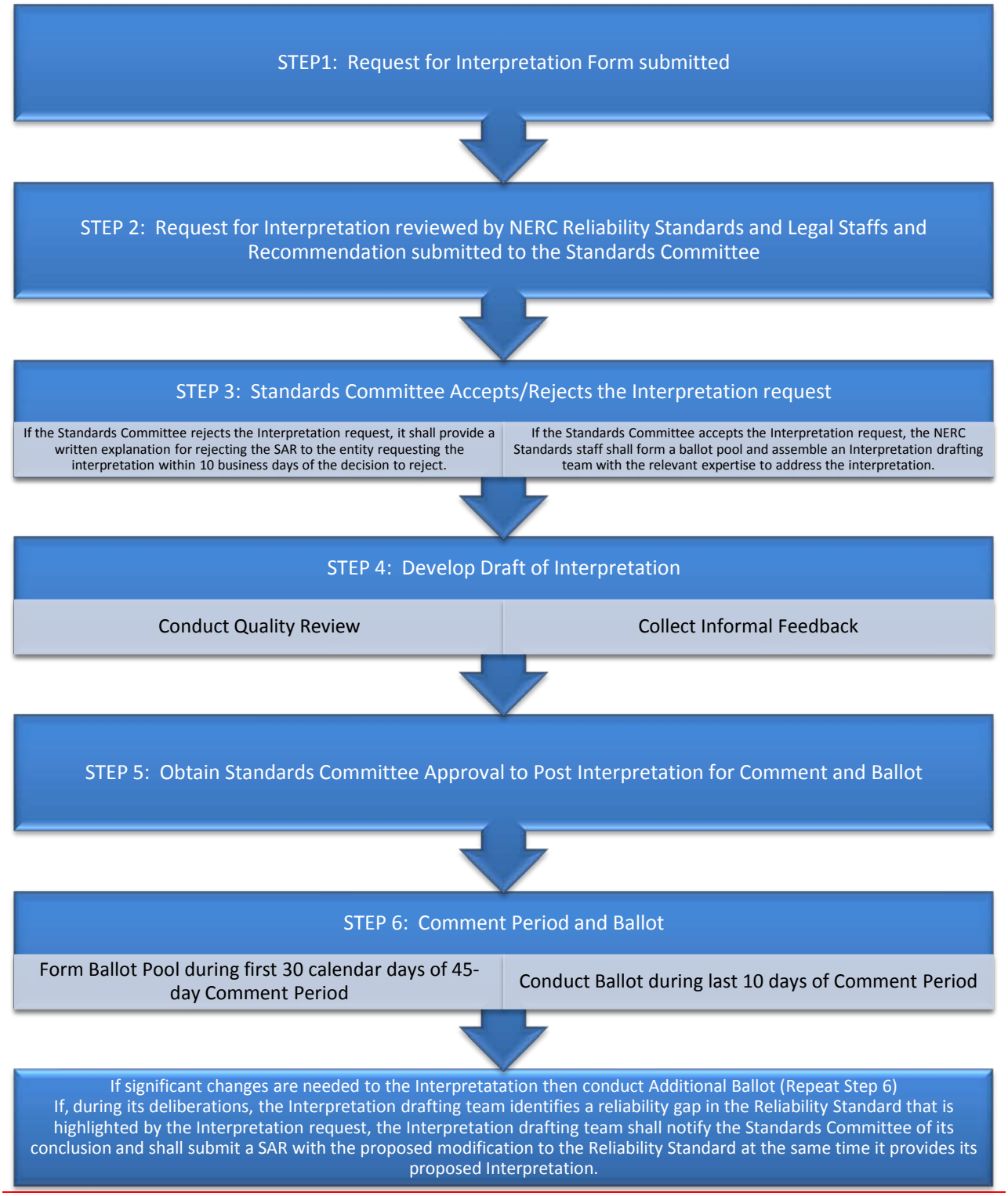
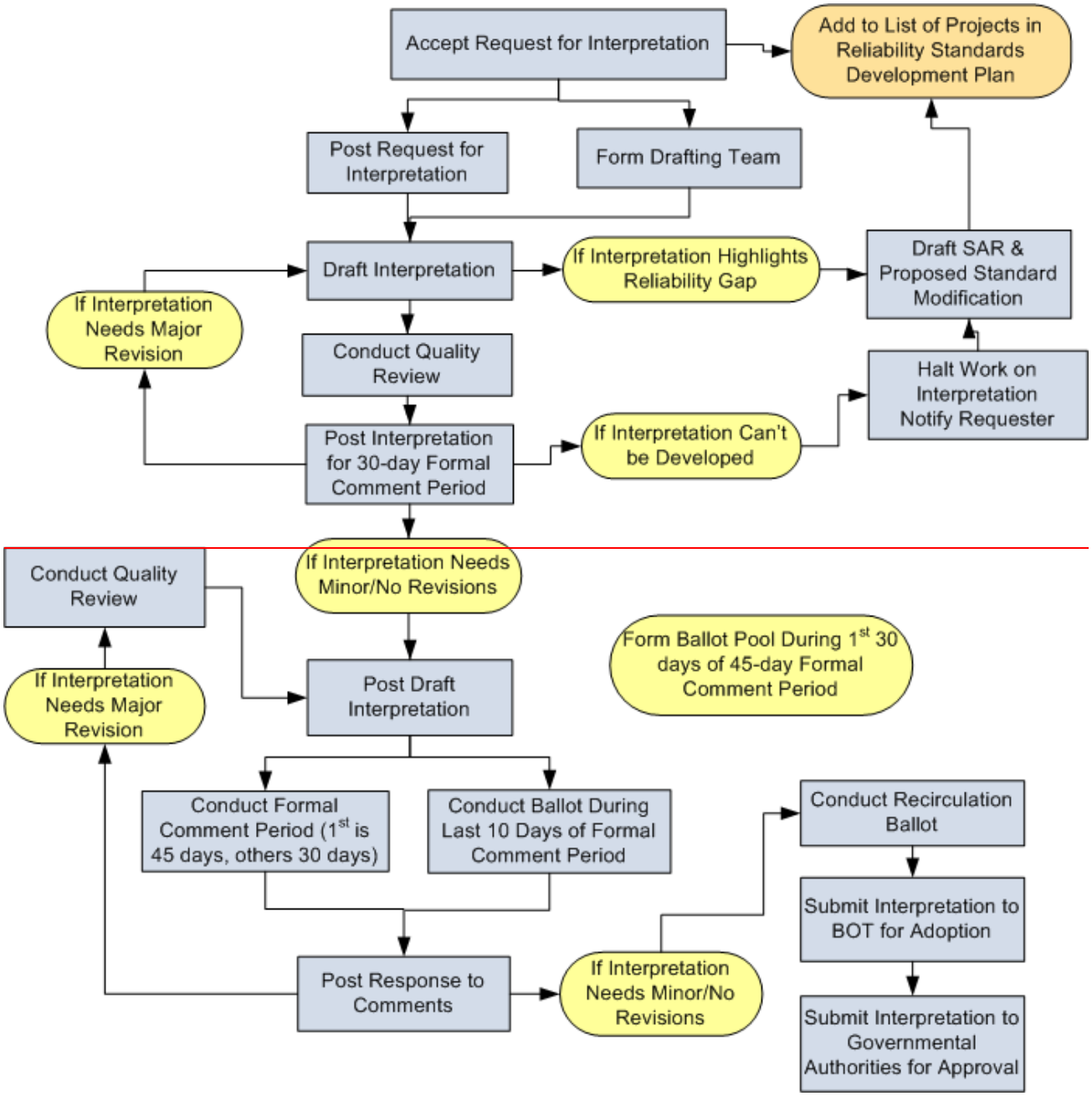

STEP1: Request for Interpretation Form submitted
STEP 2: Request for Interpretation reviewed by NERC Reliability Standards and Legal Staffs and Recommendation submitted to the Standards Committee
STEP 3: Standards Committee Accepts/Rejects the Interpretation request
If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the SAR to the entity requesting the interpretation within 10 business days of the decision to reject.
If the Standards Committee accepts the Interpretation request, the NERC Standards staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretation.
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5: Obtain Standards Committee Approval to Post Interpretation for Comment and Ballot
STEP 6: Comment Period and Ballot
Form Ballot Pool during first 30 calendar days of 45-day Comment Period
Conduct Ballot during last 10 days of Comment Period
If significant changes are needed to the Interpretatation then conduct Additional Ballot (Repeat Step 6)
If, during its deliberations, the Interpretation drafting team identifies a reliability gap in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and shall submit a SAR with the proposed modification to the Reliability Standard at the same time it provides its proposed Interpretation.



FIGURE 2: Process for Developing an Interpretation


Accept Request for Interpretation
Add to List of Projects in Reliability Standards Development Plan
Post Request for Interpretation
Form Drafting Team
Draft Interpretation
If Interpretation Highlights Reliability Gap
Draft SAR & Proposed Standard Modification
If Interpretation Needs Major Revision
Conduct Quality Review
Halt Work on Interpretation Notify Requester
Post Interpretation for 30-day Formal Comment Period
If Interpretation Can't be Developed
Conduct Quality Review
If Interpretation Needs Minor/No Revisions
Form Ballot Pool During 1st 30 days of 45-day Formal Comment Period
If Interpretation Needs Major Revision
Post Draft Interpretation
Conduct Formal Comment Period (1st is 45 days, others 30 days)
Conduct Ballot During Last 10 Days of Formal Comment Period
Conduct Recirculation Ballot
Submit Interpretation to BOT for Adoption
Post Response to Comments
If Interpretation Needs Minor/No Revisions
Submit Interpretation to Governmental Authorities for Approval

Section 8.0: Process for Appealing an Action or Inaction

Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a ~~reliability standard~~Reliability Standard, definition, ~~variance~~Variance, associated implementation plan, or ~~interpretation~~Interpretation shall have the right to appeal. This appeals process applies only to the NERC ~~reliability standards~~Reliability Standards processes as defined in this manual, not to the technical content of the ~~standards~~Reliability Standards action.

NOTE: No significant changes are proposed to the Appeals Process and nothing in this manual is intended to prescribe the ability of any entity to appeal any action or inaction resulting from the Standards Process Manual. References to appeals processes in other sections were removed to eliminate redundancy.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made in writing within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants.

8.1: Level 1 Appeal

Level 1 is the required first step in the appeals process. The appellant shall submit (to the Director of Standards) a complaint in writing that describes the procedural action or inaction associated with the ~~standards~~Reliability Standards process. The appellant shall describe in the complaint the actual or potential adverse impact to the appellant. Assisted by NERC staff and industry resources as needed, the Director of Standards shall prepare a written response addressed to the appellant as soon as practical but not more than 45 days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response shall be made a part of the public record associated with the ~~standard~~Reliability Standard.

8.2: Level 2 Appeal

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the Director of Standards, the Director of Standards shall convene a Level 2 Appeals Panel. This panel shall consist of five members appointed by the Board of Trustees. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The ~~standards~~NERC Reliability Standards staff shall post the complaint and other relevant materials and provide at least 30 days notice of the meeting of the Level 2 Appeals Panel. In addition to the appellant, any entity that is directly and materially affected by the procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The panel may, in its decision, find for the appellant and remand the issue to the Standards Committee with a statement of the issues and facts in regard to which fair and equitable action was not taken. The panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a ~~reliability standard~~Reliability Standard, definition, ~~variance~~Variance or ~~interpretation~~Interpretation or

implementation plan as these responsibilities remain with the ballot pool and Board of Trustees respectively. The actions of the Level 2 Appeals Panel shall be publicly posted.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the Board of Trustees for consideration at the time the ~~board~~Board decides whether to adopt a particular ~~reliability standard~~Reliability Standard, definition, ~~variance~~Variance or ~~interpretation~~Interpretation. The objection shall be in writing, signed by an officer of the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the facts that justify that relief. The objection shall be filed no later than 30 days after the announcement of the vote by the ballot pool on the ~~reliability standard~~Reliability Standard in question.

Section 9.0: Process for Developing a Variance

No significant changes are proposed to Section 9.0.

A ~~variance~~Variance is an approved, alternative method of achieving the reliability intent of one or more ~~requirements~~Requirements in a ~~standard~~Reliability Standard. No ~~regional entity~~Regional Entity or ~~bulk power system~~Bulk Power System owner, operator, or user shall claim a ~~variance~~Variance from a NERC ~~reliability standard~~Reliability Standard without approval of such a ~~variance~~Variance through the relevant ~~standard~~Reliability Standard approval procedure for the ~~variance.~~ Variance. Each ~~variance~~Variance from a NERC ~~reliability standard~~Reliability Standard that is approved by NERC and applicable governmental authorities shall be made an enforceable part of the associated NERC ~~reliability standard~~Reliability Standard.

NERC's drafting teams shall aim to develop ~~standards~~Reliability Standards with ~~requirements~~Requirements that apply on a continent-wide basis, minimizing the need for ~~variances~~Variances while still achieving the ~~standard's~~Reliability Standard's reliability objectives. If one or more ~~requirements~~Requirements cannot be met or complied with as written because of a physical difference in the ~~bulk power system~~Bulk Power System or because of an operational difference (such as a conflict with a ~~Federally~~federally or ~~Provincially~~provincially approved tariff), but the ~~requirement's~~Requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a ~~variance~~Variance from one or more ~~requirements~~Requirements in a continent-wide ~~standard.~~Reliability Standard. It is the responsibility of the entity that needs a ~~variance~~Variance to identify that need and initiate the processing of that ~~variance~~Variance through the submittal of a SAR[36] that includes a clear definition of the basis for the ~~variance.~~ Variance.

There are two types of ~~variances~~Variances – those that apply on an ~~interconnection~~Interconnection-wide basis, and those that apply to one or more entities on less than an ~~interconnection~~Interconnection-wide basis.

9.1: Interconnection-wide Variances

Any ~~variance~~Variance from a NERC ~~reliability standard requirement~~Reliability Standard Requirement that is proposed to apply to ~~responsible entities~~Registered Entities within a ~~regional entity~~Regional Entity organized on an ~~interconnection~~Interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that ~~regional entity's~~Regional Entity's NERC-approved ~~regional reliability standards~~Regional Reliability Standards development procedure.

While an ~~interconnection~~Interconnection-wide ~~variance~~Variance may be developed through the associated Regional ~~Entity standards~~Reliability Standards development process, ~~regional entities~~Regional Entities are encouraged to work collaboratively with existing continent-wide drafting team to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC ~~reliability standard~~Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC ~~reliability standard.~~Reliability Standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC ~~reliability standard~~Reliability Standard that is developed, in accordance with a ~~standards~~Regional Reliability Standards development procedure

[36] A sample of a SAR that identifies the need for a Variance and a sample Variance are posted as resources on the Reliability Standards Resources ~~Web Page~~web page.

approved by NERC, by a ~~regional entity~~Regional Entity organized on an ~~interconnection~~Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

9.2: Variances that Apply on Less than an Interconnection-wide Basis

Any ~~variance~~Variance from a NERC ~~reliability standard requirement~~Reliability Standard Requirement that is proposed to apply to one or more entities but less than an entire Interconnection (*e.g.*, a ~~variance~~Variance that would apply to a regional transmission organization or particular market or to a subset of ~~bulk power system~~Bulk Power System owners, operators, or users), shall be considered a Variance. A Variance may be requested while a ~~standard~~Reliability Standard is under development or a Variance may be requested at any time after a ~~standard~~Reliability Standard is approved. Each request for a Variance shall be initiated through a SAR, and processed and approved in the same manner as a continent-wide ~~standard~~Reliability Standard, using the ~~standards~~Reliability Standards development process defined in this manual.

~~Expedited Standards Development Process~~

~~NERC may need to develop a new or modified standard, VRFs, VSLs, definition, variance, or implementation plan[37] under specific time constraints (such as to meet a time constrained regulatory directive) or to meet an urgent reliability issue such that there isn't sufficient time to follow all the steps in the normal standards development process. Under those conditions, the Standards Committee shall have the authority to approve any of the following actions to expedite development:~~

- ~~Shorten the 45-day formal comment period~~
- ~~Shorten the 30-day period for forming the ballot pool~~
- ~~Allow significant modifications following the initial ballot without the need for another formal comment period provided the modifications are highlighted before conducting any successive ballot~~

~~Shorten any of the~~

~~[37] For the remainder of the description of the expedited standards development process, where the word, "standard" is used, the same process can be applied to a definition, variance, or implementation plan.~~

- Section 10 day ballot windows

If a new or modified standard is developed, approved by its ballot pool, and subsequently adopted by the NERC Board of Trustees through this expedited process, one of the following three actions shall occur[38]:

- If the standard is to be made permanent without additional substantive changes, then a SAR and a proposed standard shall be submitted to the standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay.
- If the standard is to be substantively revised or replaced by a new standard, then a project for the new or revised standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the standard was approved by stakeholders using the expedited process.
- The standard shall be withdrawn through a ballot of the stakeholders within two years of the date the standard was approved by stakeholders using the expedited process.

[38] Abbreviating the final formal comment period or a ballot window violate ANSI's accreditation requirements. The three actions that may be taken to fully process the expedited standard are intended to demonstrate NERC's commitment to meet ANSI's accreditation requirements.

.0: Processes for Developing a Reliability Standard Related to a Confidential Issue

No significant changes are proposed to Section 10.0. Changes were made to conform to Section 2.0 and 3.0.

While it is NERC's intent to use its ANSI-accredited ~~standards~~ Reliability Standards development process for developing its ~~reliability standards~~Reliability Standards, NERC has an obligation as the ERO to ensure that there are ~~reliability standards~~Reliability Standards in place to preserve the reliability of the interconnected ~~bulk power systems~~Bulk Power Systems throughout North America. When faced with a national security emergency situation, NERC may use one of the following special processes to develop a ~~standard~~Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special ~~standards~~Reliability Standards" and shall not be filed with ANSI for approval as ~~ANSI standards~~American National Standards.

The NERC Board of Trustees may direct the development of a new or revised ~~reliability standard~~Reliability Standard to address a national security situation that involves confidential issues. These situations may involve imminent or long-term threats. In general, these ~~board~~Board directives will be driven by information from the President of the United States of America or the Prime Minister of Canada or a national security agency or national intelligence agency of either or both governments indicating (to the ERO) that there is a national security threat to the reliability of the ~~bulk power system~~[39].Bulk Power System.[40]

There are two special processes for developing ~~standards~~Reliability Standards responsive to confidential issues – one process where the confidential issue is "imminent~~",~~," and one process where the confidential issue is "not imminent."

10.1: Process for Developing Reliability Standards Responsive to Imminent, Confidential Issues

If the NERC Board of Trustees directs the immediate development of a new or revised ~~reliability standard~~ Reliability Standard to address a confidential national security emergency situation, the ~~standards~~ NERC Reliability Standards staff shall develop a SAR, form a ballot pool (to vote on the ~~standard~~Reliability Standard and its implementation plan~~ and to participate in the non-binding poll of VRFs and VSLs) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's Officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.~~

~~**Drafting Team Selection**~~

~~The standard drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.~~

~~**Standards Committee Authority**~~

[39] ~~The NERC board may direct the immediate development and issuance of an Essential Action alert and then may also direct the immediate development of a new or revised reliability standard.~~

[40] The NERC Board may direct the immediate development and issuance of a Level 3 (Essential Action) alert and then may also direct the immediate development of a new or revised Reliability Standard.

~~Depending upon the level of urgency, the Standards Committee's Officers may authorize reducing or eliminating the 35-day pre-ballot review period, and may reduce the duration of both the initial ballot and the recirculation ballots to as few as 5 days, and shall allow significant modifications between the initial ballot and the recirculation ballot.~~

~~**Work of Drafting Team**~~

~~The standard drafting team shall perform all its work under strict security and confidential rules. The standard drafting team shall develop the new or revised standard, its implementation plan, and working with NERC staff shall develop associated VRFs and VSLs.~~

~~The standard drafting team shall review its work, to the extent practical, as it is being developed with officials from the appropriate governmental agencies in the U.S. and Canada, under strict security and confidentiality rules.~~

~~**Formal Stakeholder Comment & Ballot Window**~~

~~The draft standard, its implementation plan and VRFs and VSLs shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC compliance registry to perform one of the functions identified in the applicability section of the standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[41] At the same time, the standard shall be distributed to the members of the ballot pool for review and ballot. The standards staff shall not post or provide the ballot pool with any confidential background information.~~

~~The drafting team, working with the standards staff, shall consider and respond to all comments, make any necessary conforming changes to the standard, its implementation plan, and its VRFs and VSLs and shall distribute the comments, responses and any revision to the same population as received the initial set of documents for formal comment and ballot.~~

~~**Board of Trustee Actions**~~

~~Each standard and implementation plan developed through this process shall be submitted to the NERC Board of Trustees for adoption and the associated VRFs and VSLs shall be filed with the Board of Trustees for approval.~~

~~**Governmental Approvals**~~

~~All approved documents shall be filed for approval with applicable governmental authorities.~~

~~[41] In this phase of the process, only the proposed standard shall be distributed to those entities expected to comply, not the rationale and justification for the standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.~~

~~Developing a Standard Responsive to an Imminent, Confidential Issue~~

~~**Process for Developing Standards Responsive to Non-imminent, Confidential Issues**~~

~~If the NERC Board of Trustees directs the immediate development of a new or revised reliability standard to address a confidential national security emergency situation, the standards staff shall develop a SAR, form a ballot pool (to vote on the standard and its implementation plan and to participate in the non-binding poll of VRFs and VSLs~~) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's ~~Officers~~officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.2: Drafting Team Selection

The Reliability Standard drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.3: Work of Drafting Team

The Reliability Standard drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The Reliability Standard drafting team shall review its work, to the extent practical, as it is being developed with officials from the appropriate governmental agencies in the U.S. and Canada, under strict security and confidentiality rules.

10.4: Formal Stakeholder Comment & Ballot Window

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[42] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards staff shall not post or provide the ballot pool with any confidential background information.

The drafting team, working with the NERC Reliability Standards staff, shall consider and respond to all comments, make any necessary conforming changes to the Reliability Standard and its implementation plan, and shall distribute the comments, responses and any revision to the same population as received the initial set of documents for formal comment and ballot.

10.5: Board of Trustee Actions

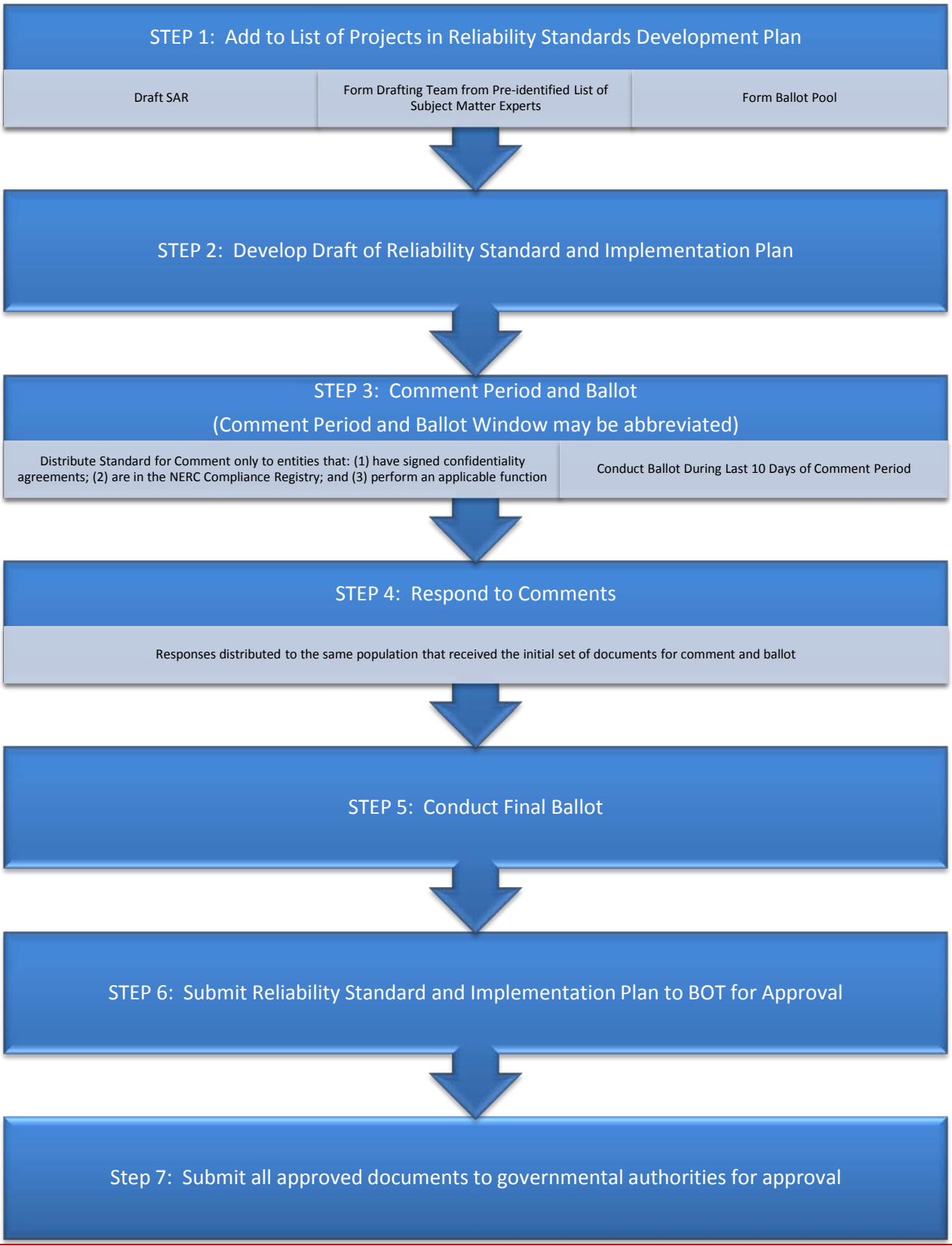
Each Reliability Standard and implementation plan developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.6: Governmental Approvals

All approved documents shall be filed for approval with applicable governmental authorities.

[42] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

10.7: Developing a Reliability Standard Responsive to an Imminent, Confidential Issue


STEP 1: Add to List of Projects in Reliability Standards Development Plan
Draft SAR
Form Drafting Team from Pre-identified List of Subject Matter Experts
Form Ballot Pool
STEP 2: Develop Draft of Reliability Standard and Implementation Plan
STEP 3: Comment Period and Ballot
(Comment Period and Ballot Window may be abbreviated)
Distribute Standard for Comment only to entities that: (1) have signed confidentiality agreements; (2) are in the NERC Compliance Registry; and (3) perform an applicable function
Conduct Ballot During Last 10 Days of Comment Period
STEP 4: Respond to Comments
Responses distributed to the same population that received the initial set of documents for comment and ballot
STEP 5: Conduct Final Ballot
STEP 6: Submit Reliability Standard and Implementation Plan to BOT for Approval
Step 7: Submit all approved documents to governmental authorities for approval

~~FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue~~

10.8: Process for Developing Reliability Standards Responsive to Non-imminent, Confidential Issues

If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.9: Drafting Team Selection

The drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.10: Work of Drafting Team

The drafting team shall perform all its work under strict security and confidential rules. The ~~standard~~Reliability Standard drafting team shall develop the new or revised ~~standard,~~ Reliability Standard and its implementation plan~~, and working with NERC staff shall develop associated VRFs and VSLs~~.

The drafting team shall review its work, to the extent practical, as it is being developed with officials from the ~~appropriate~~applicable governmental ~~agencies in the U.S. and Canada~~authorities, under strict security and confidentiality rules.

10.11: Formal Stakeholder Comment & Ballot Window

The draft ~~standard,~~ Reliability Standard and its implementation plan ~~and VRFs and VSLs~~ shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC ~~compliance registry~~Compliance Registry to perform one of the functions identified in the applicability section of the ~~standard~~Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[43] At the same time, the ~~standard~~Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The ~~standards~~NERC Reliability Standards staff shall not post or provide the ballot pool with any confidential background information.

10.12: Revisions to Reliability Standard~~, and~~ Implementation Plan~~, VRFs and VSLs~~

The drafting team, working with the ~~standards~~NERC Reliability Standards staff, shall work to refine the ~~standard,~~ Reliability Standard and implementation plan~~, VRFs and VSLs~~ in the same manner as for a new ~~standard~~Reliability Standard following the "normal" ~~standards~~Reliability Standards development process described earlier in this manual with the exception that distribution of the comments, responses, and new drafts shall be limited to those entities that are in the ballot pool and those entities that are listed in the NERC ~~compliance registry~~Compliance Registry to perform one of the functions identified in the applicability section of the ~~standard~~Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.

10.13: Board of Trustee Action

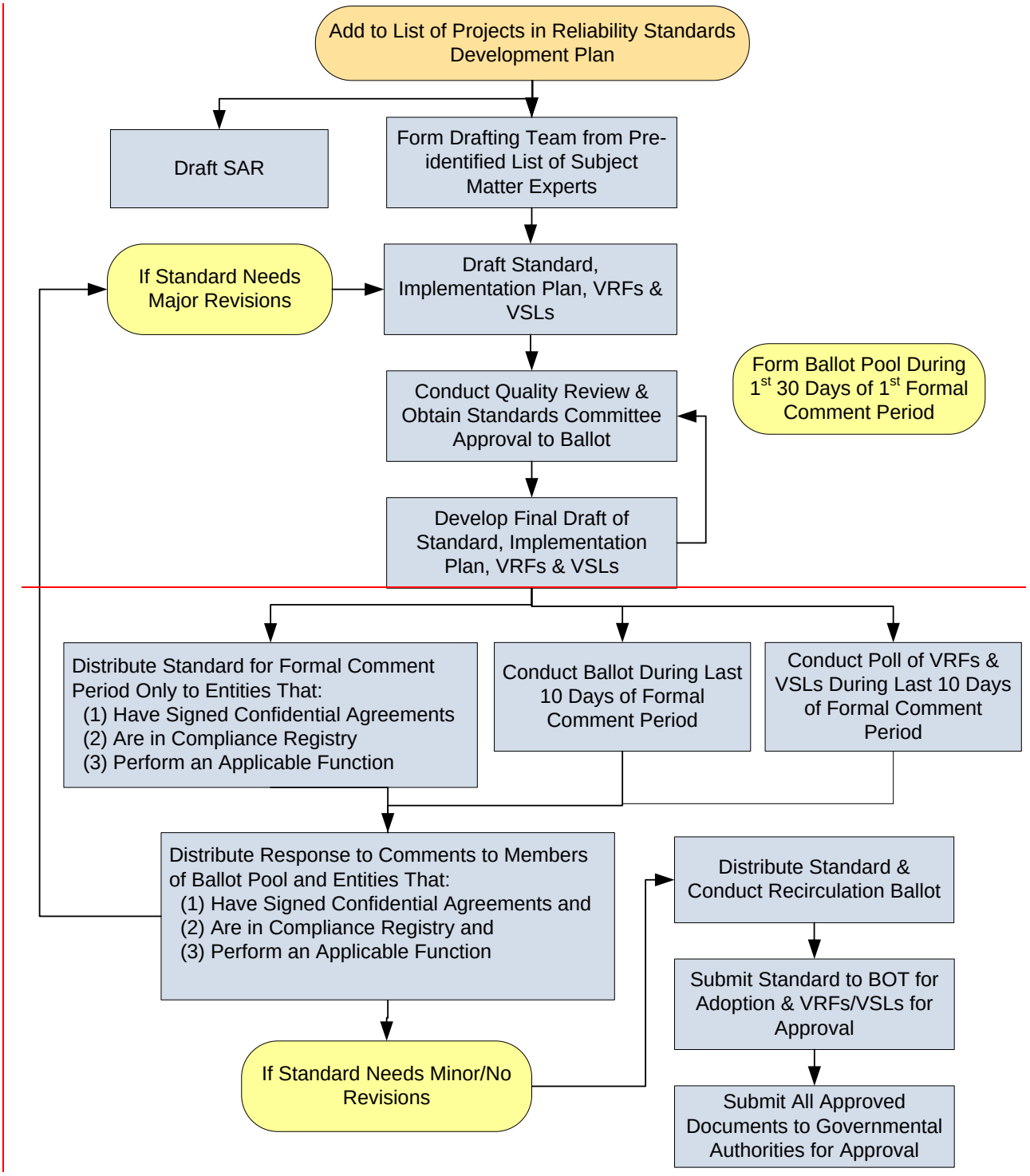
[43] In this phase of the process, only the proposed ~~standard~~Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the ~~standard.~~Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

Each ~~standard~~Reliability Standard and implementation plan developed through this process shall be submitted to the NERC Board of Trustees for adoption~~ and the associated VRFs and VSLs shall be filed with the Board of Trustees for approval~~.

10.14: Governmental Approvals

All approved documents shall be filed for approval with applicable governmental authorities.

Developing a Reliability Standard Responsive to a Non-imminent, Confidential Issue


Add to List of Projects in Reliability Standards Development Plan
Draft SAR
Form Drafting Team from Pre-identified List of Subject Matter Experts
If Standard Needs Major Revisions
Draft Standard, Implementation Plan, VRFs & VSLs
Form Ballot Pool During 1st 30 Days of 1st Formal Comment Period
Conduct Quality Review & Obtain Standards Committee Approval to Ballot
Develop Final Draft of Standard, Implementation Plan, VRFs & VSLs
Distribute Standard for Formal Comment Period Only to Entities That:
(1) Have Signed Confidential Agreements
(2) Are in Compliance Registry
(3) Perform an Applicable Function
Conduct Ballot During Last 10 Days of Formal Comment Period
Conduct Poll of VRFs & VSLs During Last 10 Days of Formal Comment Period
Distribute Response to Comments to Members of Ballot Pool and Entities That:
(1) Have Signed Confidential Agreements and
(2) Are in Compliance Registry and
(3) Perform an Applicable Function
Distribute Standard & Conduct Recirculation Ballot
Submit Standard to BOT for Adoption & VRFs/VSLs for Approval
If Standard Needs Minor/No Revisions
Submit All Approved Documents to Governmental Authorities for Approval

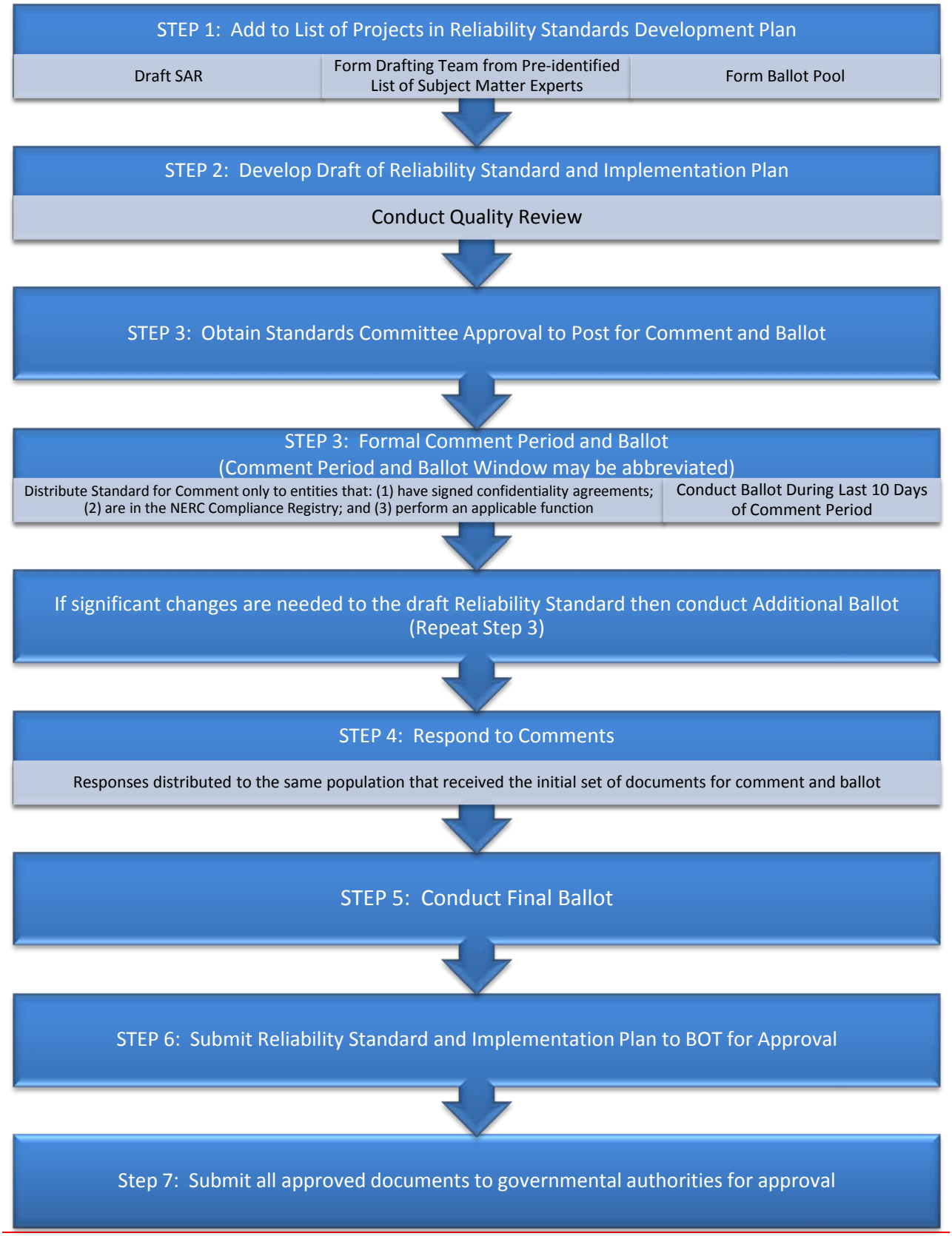

STEP 1: Add to List of Projects in Reliability Standards Development Plan
Draft SAR
Form Drafting Team from Pre-identified List of Subject Matter Experts
Form Ballot Pool
STEP 2: Develop Draft of Reliability Standard and Implementation Plan
Conduct Quality Review
STEP 3: Obtain Standards Committee Approval to Post for Comment and Ballot
STEP 3: Formal Comment Period and Ballot
(Comment Period and Ballot Window may be abbreviated)
Distribute Standard for Comment only to entities that: (1) have signed confidentiality agreements; (2) are in the NERC Compliance Registry; and (3) perform an applicable function
Conduct Ballot During Last 10 Days of Comment Period
If significant changes are needed to the draft Reliability Standard then conduct Additional Ballot
(Repeat Step 3)
STEP 4: Respond to Comments
Responses distributed to the same population that received the initial set of documents for comment and ballot
STEP 5: Conduct Final Ballot
STEP 6: Submit Reliability Standard and Implementation Plan to BOT for Approval
Step 7: Submit all approved documents to governmental authorities for approval

FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for Approving Supporting Documents

No significant changes are proposed to Section 11.0.

The following types of documents are samples of the types of supporting documents that may be developed to enhance stakeholder understanding and implementation of a ~~reliability standard.~~Reliability Standard. These documents may explain or facilitate implementation of ~~standards~~Reliability Standards but do not themselves contain mandatory ~~requirements~~Requirements subject to compliance review. Any ~~requirements~~Requirements that are mandatory shall be incorporated into the ~~standard~~Reliability Standard in the ~~standard~~Reliability Standard development process.

While most supporting documents are developed by the drafting team working to develop the associated ~~standard~~Reliability Standard, any entity may develop a supporting document associated with a ~~reliability standard~~Reliability Standard.

The Standards Committee shall authorize the posting of all supporting references[44] that are linked to an approved ~~standard.~~Reliability Standard. Prior to granting approval to post a supporting reference with a link to the associated ~~standard~~Reliability Standard, the Standards Committee shall verify that the document has had stakeholder review to verify the accuracy of the technical content. While the Standards Committee has the authority to approve the posting of each such reference, stakeholders, not the Standards Committee, verify the accuracy of the document's contents.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding and interpretation of a ~~reliability standard.~~Reliability Standard. A standard reference may support the implementation of a ~~reliability standard~~Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.
Guideline	Recommended process that identifies a method of meeting a ~~requirement~~Requirement under specific conditions.
Supplement	Data forms, pro forma documents, and associated instructions that support the implementation of a ~~reliability standard~~Reliability Standard.
Training Material	Documents that support the implementation of a ~~reliability standard~~Reliability Standard.
Procedure	Step-wise instructions defining a particular process or operation. Procedures may support the implementation of a ~~reliability standard~~Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.
White Paper	An informal paper stating a position or concept. A white paper may be used to propose preliminary concepts for a ~~standard~~Reliability Standard or one of the

[44] The Standards Committee's Procedure for Approving the Posting of Reference Documents is posted on the Reliability Standards Resources ~~Web Page~~web page.

	documents above.

Section 12.0: Process for Correcting Errata

No significant changes are proposed to Section 12.0.

From time to time, an error may be discovered in an approved ~~reliability standard.~~Reliability Standard. If the Standards Committee agrees that the correction of the error does not change the scope or intent of the associated ~~standard~~Reliability Standard, and agrees that the correction has no material impact on the end users of the ~~standard~~Reliability Standard, then the correction shall be ~~submitted for information to the NERC Board of Trustees and~~ filed for approval with applicable governmental authorities. The NERC Board of Trustees has resolved to concurrently approve any errata approved by the Standards Committee.

Section 13.0: Process for Conducting ~~Five-Year Review~~Periodic Reviews of Reliability Standards

~~Each reliability standard developed through NERC's~~
All Reliability Standards shall be reviewed at least once every ten years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later. If a Reliability Standard s is approved by ANSI ~~accredited standards development process~~ as an American National Standard, it shall be reviewed at least once every five years from the effective date of the ~~standard~~Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the ~~standard~~Reliability Standard, whichever is later.

Rationale: The purpose of the revisions to Section 13.0 is to limit the five year review of standards to only American National Standards. All other standards will be reviewed on a ten year cycle. This is consistent with ANSI requirements and will allow for efficiency gains. The Standards Committee has the authority to provide for a review of any standard on an as-needed basis.

Please note that NERC currently does not have any standards that have been submitted to ANSI for approval as American National Standards.

The *Reliability Standards Development Plan* shall include projects that address this five or ten-year review of ~~standards~~Reliability Standards.

- If a ~~standard~~Reliability Standard is nearing its five or ten-year review and has issues that need resolution, then the *Reliability Standards Development Plan* shall include a project for the complete review and review and associated revision of that ~~standard~~Reliability Standard that includes addressing all outstanding governmental directives, all approved ~~interpretations~~Interpretations, and all unresolved issues identified by stakeholders.
- If a ~~standard~~Reliability Standard is nearing its five or ten-year review and there are no outstanding governmental directives ~~interpretations~~, Interpretations, or unresolved stakeholder issues associated with that ~~standard~~Reliability Standard, then the Reliability *Standards Development Plan* shall include a project solely for the "five-year review" of that ~~standard~~Reliability Standard.

For a project that is focused solely on the five-year review, the Standards Committee shall appoint a review team of subject matter experts to review the ~~standard~~Reliability Standard and recommend whether the ~~standard~~American National Standard Institute-approved Reliability Standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a 45~~-~~ calendar day formal stakeholder comment period and shall provide those stakeholder comments to the Standards Committee for consideration.

- If a review team recommends reaffirming a ~~standard~~Reliability Standard, the Standards Committee shall submit the reaffirmation to the Board of Trustees for adoption and then to applicable governmental authorities for approval. Reaffirmation does not require approval by stakeholder ballot.
- If a review team recommends modifying, or ~~withdrawing~~retiring a ~~standard~~Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the Standards Committee for prioritization as a new project. Each existing ~~standard~~Reliability Standard recommended for modification, or ~~withdrawal~~retirement shall remain in effect in accordance with the associated implementation plan until the

action to modify or withdraw the ~~standard~~Reliability Standard is approved by its ballot pool, adopted by the Board of Trustees, and approved by applicable governmental authorities.

In the case of reaffirmation of a ~~standard~~Reliability Standard, the ~~standard~~Reliability Standard shall remain in effect until the next five or ten-year review or until the ~~standard~~Reliability Standard is otherwise modified or withdrawn by a separate action.

Section 14.0: Public Access to Reliability Standards Information

14.1: Online Reliability Standards Information System

No changes are proposed to Section 14.0.

The ~~standards~~NERC Reliability Standards staff shall maintain an electronic copy of information regarding currently proposed and currently in effect ~~reliability standards.~~Reliability Standards. This information shall include current ~~standards~~Reliability Standards in effect, proposed revisions to ~~standards~~Reliability Standards, and proposed new ~~standards~~Reliability Standards. This information shall provide a record, for at a minimum the previous five years, of the review and approval process for each ~~reliability standard~~Reliability Standard, including public comments received during the development and approval process.

14.2: Archived Reliability Standards Information

The NERC staff shall maintain a historical record of ~~reliability standards~~Reliability Standards information that is no longer maintained online. Archived information shall be retained indefinitely as practical, but in no case less than five years or one complete standard cycle from the date on which the ~~standard~~Reliability Standard was no longer in effect. Archived records of ~~standards~~Reliability Standards information shall be available electronically within 30 days following the receipt by the ~~standards~~NERC Reliability Standards staff of a written request.

Section 15.0: Process for Updating ~~Standards~~Standard Processes

15.1: Requests to Revise the Standard Processes Manual

No changes are proposed to Section 15.0.

Any person or entity may submit a request to modify one or more of the processes contained within this manual. The Standards Committee shall oversee the handling of each request. The Standards Committee shall prioritize all requests, merge related requests, and respond to each sponsor within 30 calendar days.

The Standards Committee shall post the proposed revisions for a 45~~-~~ (calendar) day formal comment period. Based on the degree of consensus for the revisions, the Standards Committee shall:

a. Submit the revised process or processes for ballot pool approval;
b. Repeat the posting for additional inputs after making changes based on comments received;
c. Remand the proposal to the sponsor for further work; or
d. Reject the proposal.

The Registered Ballot Body shall be represented by a ballot pool. The ballot procedure shall be the same as that defined for approval of a ~~standard~~Reliability Standard, including the use of ~~a recirculation ballot~~an Additional Ballot if needed. If the proposed revision is approved by the ballot pool, the Standards Committee shall submit the revised procedure to the ~~board~~Board for adoption. The Standards Committee shall submit to the ~~board~~Board a description of the basis for the changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed revisions shall not be effective until approved by the NERC Board of Trustees and applicable governmental authorities.

Section 16.0: Waiver

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC may need to develop a new or modified Reliability Standard, definition, Variance, or implementation plan under specific time constraints (such as to meet a time constrained regulatory directive) or to meet an urgent reliability issue such that there isn't sufficient time to follow all the steps in the normal Reliability Standards development process.

The Standards Committee may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:

The waiver provision has been added to allow the standards Committee some flexibility in administering the Standards Process to meet reliability needs. This flexibility will increase both efficiency and effectiveness of standards delivery.

Addition of a waiver provision to create this flexibility is responsive to SPIG Recommendations 1 and 5 and the following suggestion: "*Improve efficiencies (to avoid taking too long)*"

- Where necessary to meet regulatory deadlines;
- Where necessary to meet deadlines imposed by the NERC Board of Trustees; or
- Where the Standards Committee determines that a modification to a proposed Reliability Standard or its Requirement(s), a modification to a defined term, a modification to an interpretation, or a modification to a variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.

In no circumstances shall this provision be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. The Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance.

Reliability Standards developed as a result of a waiver of any provision of the Standard Processes Manual shall not be filed with ANSI for approval as American National Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual Revisions: SCPS White Papers for Background Information

June 18, 2012

RELIABILITY | ACCOUNTABILITY






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Introduction

Background

At its February 9, 2012 meeting, the NERC Board of Trustees (BOT) requested the assistance of the NERC Member Representatives Committee (MRC) to provide policy input, and a proposed framework, for specific improvements to the standards development process. The MRC Chair and Vice Chair invited several members of the MRC, two NERC BOT members, the NERC CEO, and the SC Chair – the group collectively known as the Standards Process Input Group (SPIG) – to join with them as participants in developing recommendations to improve the standards development process in the following key areas:

- Clarity on the reliability objectives, technical parameters, scope, and the relative priority of the standards project
- The drafting process (developing the specific technical content of the standard)
- Standards project management and workflow
- Formal balloting and commenting

To help ensure that the SPIG focused its efforts on the most important areas for improvement, the group began its work by gathering input from subject matter experts, including the regions, the MRC, standard drafting team leaders, NERC staff, and other stakeholders. This input was collected through a series of interviews, supplemented by a formal survey.

Based on that input, the SPIG produced a document with five recommendations to modify the way NERC develops Reliability Standards and other solutions intended to improve the priority, product, and process of standards development:

1. **American National Standards Institute (ANSI):** NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.

2. **Reliability Issues Steering Committee (RISC):** The NERC BOT is encouraged to form a RISC to conduct front-end, high-level reviews of nominated reliability issues and direct the initiation of standards projects or other solutions that will address the reliability issues.

3. **Interface with Regulatory and Governmental Authorities:** The NERC BOT is encouraged to task NERC management, working with a broad array of Electric Reliability Organization resources (e.g., the MRC, technical committees, Regional Entities, trade associations, etc.) to develop a strategy for improving the communication and awareness of effective reliability risk controls to increase input and alignment with state, federal, and provincial authorities.

4. **Standards Product Issues:** The NERC BOT is encouraged to require that the standards development process address the use of results-based standards; cost effectiveness of standards and standards development; alignment of standards requirements/measures

with Reliability Standards Audit Worksheets (RSAWs); and the retirement of standards no longer needed to meet an adequate level of reliability.

5. **Standards Development Process and Resource Issues:** The NERC BOT is encouraged to require the standards development process to be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The BOT is also encouraged to require standard development resources to achieve and address formal and consistent project management and efficient formation and composition of standard drafting teams.

The recommendations also aim to strengthen consensus building, first on the need for a standard, and then on the requirements themselves.

These recommendations were presented to the BOT and approved on May 9, 2012, and the SC was specifically charged with addressing SPIG Recommendations 1, 4, and 5. The SC has organized this effort by leveraging each of its subcommittees, the Process Subcommittee (SCPS) and the Communications and Planning Subcommittee (SCCPS), to work in parallel on developing proposed revisions and conducting outreach to industry stakeholders to ensure that all interested stakeholders have an opportunity to provide their input.

SCPS Sub-Teams, Proposed Revisions to the Standard Processes Manual

Since May, sub-teams of the Standards Committee Process Subcommittee (SCPS), supported by NERC standards and legal staff, have developed proposed revisions to the Standard Processes Manual (SPM) and associated changes to Section 300 of NERC's Rules of Procedure (ROP). These sub-teams have focused on changes in the following categories based on the SPIG recommendations:

- Sub-team 1: Analysis of American National Standards Institute requirements and streamlining commenting and balloting
- Sub-team 2: Essential elements of a standard (elimination of measures, VRFs, and VSLs)
- Sub-team 3: Options for handling 'no' votes to ensure drafting teams have the information they need to perform their work
- Sub-team 4: Cost Effective Analysis Process

The proposed revisions from these sub-teams are included in the posted redline version of the SPM, and the SCPS is looking forward to industry feedback on its work. To support the proposed revisions, each sub-team developed a white paper to document its research and rationale for its revisions. Those white papers are included herein.

In sum, the proposed revisions include provisions for:

- Revised drafting team composition to incorporate SPIG recommendation to include lawyers and compliance experts; incorporated SPIG recommendation that drafting teams participate in developing RSAWs and compliance elements.

- Elimination of VRFs/VSLs and incorporation of Measures into RSAWs

- A streamlined standards development process, including:
    - Elimination of the 30 day comment period;
    - Providing for summary responses for comments. Instead of requiring written responses to each individual comment, drafting teams will have the flexibility to respond in summary form. However, the summaries must address each of the issues raised;
    - Elimination of negative votes without comments and negative votes with unrelated comments in the calculation of consensus;
    - Provisions to allow for quality reviews to be conducted in parallel with standard development

- Incorporation of a waiver provision to allow for modifications to the standards development process for good cause.

Sub-team 1 White Paper: Analysis of ANSI Requirements and Streamlining of Commenting and Balloting

Sub-team 1 performed a comparative review of the specific steps in standards development between the existing NERC standard development process and the ANSI requirements for standards development. Also included in the review were the process requirements of the North American Energy Standards Board (NAESB) and the National Electrical Manufacturers Associations (NEMA), other standard developers that follow the ANSI process. The sub-team wanted to review how other companies that maintain ANSI accreditation have implemented the process to identify any efficiencies that might be acceptable to the NERC process, but the sub-team did not develop any specific recommendations based on the review of these companies' process.

The sub-team addressed the following aspects of the NERC standards development process in its review:

- Project Initiation
- Comment Periods
- Consideration of Views and Objections
- Successive Balloting
- Weighted-Segment Voting Scheme
- Negative Votes Without Requirements
- Ballot Period
- Appeals
- Interpretations Policy
- Expedited Standards Development Process
- Five Year Review
- Drafting Team Formation
- Standards Committee
- Informal Feedback
- Quality Review
- Non-Binding Polls
- Errata
- Definitions
- Modifications to Standards Procedure
- Compliance Elements
- Field Tests and Collecting and Analyzing Data
- Variances
- General Comment

To facilitate the review, a spreadsheet was used to summarize the data from the ANSI review and the balloting and commenting discussions which were based on the SPIG recommendations. The spreadsheet includes a summary of the ANSI requirements, the other standard developers' process and the recommendations from the teams. There are also additional columns that include the team's discussion and notes should they need to be referred to going forward.

Throughout its review, the sub-team referred to the following five questions to guide its thinking:

1. Is there reason the NERC process is different from the ANSI requirements?
2. If we recommend using the minimum ANSI requirements, thus reducing the requirements of the current NERC process, will be the development of consensus be more difficult?
3. If we move to the minimum ANSI requirement, is there some other way to build consensus?
4. If a change to an existing NERC development step is proposed, are there examples that demonstrate the need for that change?
5. What actions (e.g., document changes or approval, software changes) are needed to make the recommended changes?

Recommendations

Currently, some elements of the NERC standards process partially exceed ANSI Essential Requirements, and others entirely exceed them. NERC meets and will continue to meet the minimum requirements for ANSI accreditation of its standards development process. Sub-team 1 suggested several changes that make the NERC standards process less stringent, while maintaining ANSI accreditation, to decrease the burden on drafting teams, stakeholders, and NERC staff without sacrificing quality.

In accordance with ANSI requirements, in the proposed process revisions, only one formal comment period is required, and drafting teams are only required to provide written responses to comments received in the formal comment period. These written responses may be given in summary form, not individually, although the drafting team may elect to respond to individual comments as deemed appropriate. The drafting team may employ informal comment periods to collect stakeholder feedback, but it will not be required to respond to comments obtained in informal forums, though it may respond if deemed appropriate.

The sub-team has also proposed that negative votes submitted without comment will be included in the determination of quorum but will *not* be included in the ballot pool approval. This change encourages stakeholders to submit constructive feedback any time they vote "no" on a standard.

In addition to these specific process requirement changes, Sub-team 1 has proposed that additional project management and facilitation support be made available to drafting teams as needed.

Sub-team 2 White Paper: Essential Elements of a Standard (Elimination of Measures, VRFs, and VSLs)

One of the SPIG's five recommendations relates to improving the NERC Standard Development Process and states:

> **Recommendation 4: Standards Product Issues**
>
> The NERC board is encouraged to require that the standards development process address:
>
> - The use of results–based standards (RBS);
> - Cost effectiveness of standards and standards development;
> - Alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and
> - The retirement of standards no longer needed to meet an adequate level of reliability.

One of the specific recommendations within that larger recommendation encouraged NERC's BOT to revise the Essential Elements of the Standards Template to eliminate redundancies such as Violation Severity Levels (VSLs).

In addressing Recommendation 4 and the specific recommendation just cited, the SCPS revisited the need for including certain compliance elements within a standard. In analyzing this issue, the SCPS developed a proposal whereby measures would be removed from the standard template in favor of adding more detail to RSAWs and better aligning the work of standard drafting teams (SDTs) with the content of the RSAW. The SCPS also suggests eliminating VSLs and VRFs from a standard in favor of a Sanction Table. The sections below detail the SCPS's work on these issues.

Measures

RSAWs are a valuable tool used by both Compliance Auditors and Registered Entity personnel. When carefully drafted, an RSAW can serve as a source of information on the expectations of the requirements in the standard as well as a permanent record for information of how an entity demonstrated their compliance with a requirement. RSAWs to date are not consistent in quality, nor are they equally helpful to those who use them.

In the past, RSAWs have been developed after a reliability standard was approved by the Registered Ballot Body and often after FERC approval of the subject reliability standard. RSAWs typically did not incorporate the input of the subject matter experts who developed the

reliability standard and are the best resource when it comes to the intention of the words in the standard.

Issues and Explored Alternatives

Even before the SPIG issued its recommendations, a sub-team of the SCPS developed a proposal for members of the SDT to work with NERC compliance staff in the development of the RSAW. The SCPS first considered the logistics of the SDT coordination when it comes to writing RSAWs:

- At what point in the development of the standard should this coordination start? If it's too early, requirements may change substantially, resulting in the rework of RSAW. If it's too late, then the assistance that may be gained in making sure that a requirement is clear and measurable could be lost.
- Who on the SDT would participate in the RSAW development? Or would it make more sense for compliance staff (from NERC or the regions) to participate in the SDT meetings throughout the development or at a particular point in the development? Or would it make more sense to have volunteers from NERC's Compliance & Certification Committee work with the SDT? Or should anyone who completed quality review training and had experience in a compliance department, including the compliance department of a registered entity, work as a member of the SDT in developing both the standard and the RSAW?
- Should the lawyers who help write a standard or participate on quality review teams help draft RSAWs? If they don't help with drafting, should they do a review before the RSAW is finalized to determine that the RSAW supports but does not expand on the requirements in the standard?

Next, the SCPS considered the level of detail necessary for the RSAW:

- Would it include examples of how to be compliant with a requirement along with examples of what non-compliance might look like and why?
- Would things like suggested sample size be included?
- Would it identify when attestations might be sufficient?
- Once we determine what the "ideal" RSAW looks like, should we develop a training program and require those who will develop RSAWs to participate in the training?

Next, the SCPS considered what kind of vetting the draft RSAW would need within the industry

- How much transparency do we need?
- What quantity of industry resources should it consume (being mindful of balance between opportunity for input and overwhelming industry)?
- Should there be a separate legal review, or would that be covered in the quality review of the standard?
- Should it be completed and ready for a non-binding poll at the same time the VSLs and VRFs are balloted?

- Should it be included in the package that goes to the NERC BOT for approval along with the VSLs and VRFs?
- Should it be included in the package that is sent to FERC?

Recommendations

Ultimately, the SCPS determined that there are many benefits to including SDT members in the development of RSAWs. An SDT could offer detail in the following categories:

- True understanding of what is intended by the words of the standard; description of the requirement and reliability intent (from the rationale, needs/goals/objectives) in the standard.
- An illustrative list of how to meet performance and for each "how," what constitutes quality evidence that would be sufficient.
- Examples of what non-compliance might look like (e.g. "if the evidence is missing a date, it would not be considered compliant."), if appropriate.
- Any applicable or appropriate boundaries or parameters within which there is auditor discretion (performance may be acceptable), if any.
- Identify if attestations are acceptable to "prove negative" and if there is any corroborating evidence that is "reasonable" to provide.

Including SDTs in work on RSAWs could also minimize and eventually do away with the need for CANs and formal interpretations of standards. And if RSAWs were provided to the BOT at the same time as the standard, the industry would have a "learning period" to get ready for the mandatory enforcement date. Compliance could help with performing mock audits to assist in educating the registered entities of what is expected, which would lead to a major increase in transparency.

Based on this analysis, a proposal for removing measures from the standard and adding detail to RSAWs, using input from SDTs, has been incorporated into the proposed revisions to the SPM.

VRFs and VSLs

Currently, the NERC Standards Development Process requires the development of Reliability Standards that include components that work collectively to identify what entities must do to meet their reliability-related obligations. Additionally, the Reliability Standard documents the elements necessary to demonstrate, monitor, and assess compliance with the requirements. These elements include the Violation Risk Factors (VRFs) and the Violation Severity Levels (VSLs).

VRFs and VSLs are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved Reliability Standard. Each requirement in each Reliability Standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC staff, at the same time as the associated standard, but they are not part of the standard. The BOT is responsible for approving VRFs and VSLs. The terms VRF and VSL are defined below:

Violation Risk Factors: identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria.

Violation Severity Levels: define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.

Issues

Violation Risk Factors (VRFs):

The present VRF-associated definitions were never vetted through the NERC Standards Process, primarily due to time constraints during the ERO startup. While the definitions were a useful start, this has led to a series of problems, which include:

- Lack of clear divisions between risk levels led to inconsistency in the application of VRFs
- A small number of levels (lack of granularity) led to assigning the same VRF to requirements with significantly different reliability-related risks
- Number of FERC-directed changes point to an underlying lack of clarity, consistency, and transparency in the assignment of VRFs
- The industry has confused reliability risk with importance

The factors above have led to an inconsistent approach in the assignment of VRFs in the standards development and approval process that tends to inflate assigned risk. The present VRF guidance established by the NERC Standards Committee is based on guidelines presented in Commission (FERC) Order on Violation Risk Factors, 119 FERC ¶ 61,145 at P 17 (2007) and Order on Violation Severity Levels Proposed by the Electric Reliability Organization, 123 FERC ¶ 61,284 (2008). These guidelines contribute to the difficulties associated with the assignment of VRFs and adherence to these guidelines further contributes to the SDT's inflation of assigned risk. The VRF Guidelines are summarized below:

- **Guideline (1)** — Consistency with the Conclusions of the Final Blackout Report
- **Guideline (2)** — Consistency within a Reliability Standard
- **Guideline (3)** — Consistency among Reliability Standards
- **Guideline (4)** — Consistency with NERC's Definition of the Violation Risk Factor Level
- **Guideline (5)** — Treatment of Requirements that Co-mingle More Than One Obligation

While the VRF is currently considered a useful tool by enforcement for assessing violations, the assignment of VRFs by SDTs is a burdensome activity that lengthens the development phase of standard projects and further extends the process and consumes resources during the balloting phase where the VRFs are presented to the industry in a non-binding poll. Additionally, the SDT

is responsible for documenting the rationale for the VRF assignments as part of the request to regulatory authorities to approve the standard.

Violation Severity Levels (VSLs):

The present VSL guidance established by the NERC Standards Committee was based initially on guidelines presented in Commission (FERC) *Order on Violation Severity Levels*, dated June 19, 2008, and supplemented by guidance specific to CIP standards in the March 18, 2010 Order Addressing VSL Assignments in CIP Standards. The guidance directs SDTs to develop and assign a VSL (many with multiple levels of severity) to each requirement contained in a Reliability Standard. These guidelines are summarized below:

- **Guideline 1:** Violation Severity Level assignments should not have the unintended consequence of lowering the current level of compliance.
- **Guideline 2:** Violation Severity Level assignments should ensure uniformity and consistency in the determination of penalties.
- **Guideline 3:** Violation Severity Level assignment should be consistent with the corresponding requirement
- **Guideline 4:** Violation Severity Level assignment should be based on a single violation, not on a cumulative number of violations

For CIP Standards:

- Requirements where a single lapse in protection can compromise computer network security, i.e., the "weakest link" characteristic, should apply binary rather than gradated Violation Severity Levels; 11 and
- Violation Severity Levels for cyber security Requirements containing interdependent tasks of documentation and implementation should account for their interdependence.

These guidelines establish very burdensome responsibilities to the SDT which significantly lengthens the development phase of Reliability Standard projects and further extends the process and consumes resources during the balloting phase where the VSLs are presented to the industry in a non-binding poll. Additionally, the SDT is responsible for documenting the justification for the VSLs, along with how each VSL meets each of the Commission's (FERC) guidelines, as part of the request to regulatory authorities to approve the standard. The NERC standards staff estimates that a single set of five VSLs of mixed complexity requires an investment of more than 300 hours when considering the time invested by the drafting team, stakeholders, and staff in developing, reviewing, revising, and balloting the VSLs.

Explored Alternatives

Several options have been explored by the NERC Standards Committee, the NERC Standards Committee Process Subcommittee, the NERC Compliance and Certification Committee, and various subgroups. Recent efforts were directed in the following areas:

- Violation Risk Factors (VRFs):

A subgroup comprised of industry stakeholders, as well as NERC, Regional and regulatory staff was formed to evaluate the current three-tier approach to defining the VRFs and provide recommendations for improvements to the definitions which would clarify the VRF levels and allow SDTs to accurately assign the correct VRF to each requirement. The subgroup recommended an expansion of the current 3-tier approach to a 5-tier approach to better qualify the risk the violation of a given requirement will have on reliability.

- Violation Severity Levels (VSLs):

  A subgroup comprised of industry stakeholders, as well as NERC, Regional and regulatory staff was formed and directed to review a proposal from the Standards Committee Process Subcommittee to evaluate the feasibility of applying a pro forma based VSL approach to reliability standards. The subgroup concluded that while the VSL pro forma proposal approach has merit, it is not practical at this time.

  The objective of the proposals was to reduce the effort standard drafting teams expend in assigning VRFs and developing VSLs for each requirement and to help improve stakeholder approval of standards hindered by perceived issues with a standard's proposed VRFs or VSLs. The conclusions for each effort were that although the final work product provides needed support to the SDTs, the efforts associated assigning VRFs and developing VSLs remain burdensome responsibilities to the SDT which significantly lengthens the development phase of Reliability Standard projects and further extends the process by consuming resources during the balloting phase where the VRFs and VSLs are presented to the industry in a non-binding poll.

Use of VRFs and VSLs in Enforcement Activities

VRFs and the VSLs are compliance elements of a Reliability Standard and utilized as such during the enforcement process. The NERC Rules of Procedure Appendix 4B *Sanction Guidelines of the North American Electric Reliability Corporation*, Section 4.1 *Initial Value Range of the Base Penalty Amount* states:

NERC or the regional entity will determine an initial value range for the Base Penalty Amount by considering two factors regarding the violation: the Violation Risk Factor (VRF) of the requirement violated and the Violation Severity Level (VSL) assessed for the violation. Using the Base Penalty Amount Table, NERC or the regional entity will look up the initial value range for the Base Penalty Amount by finding the intersection of the violation's VRF and VSL on the table.

The current Base Penalty Amount Table provides high and low limits for the initial monetary range associated with a violation.

Recommendations

In an effort to be responsive to the SPIG recommendations, to ease the burden on the SDTs, and to provide an opportunity to shorten the development timeframes associated with standard development projects, it is the recommendation of this sub-team to eliminate the

Violation Risk Factor (VRF) and the Violation Severity Level (VSL) from the essential elements of a Reliability Standard.

Recognizing the need to be able to determine the Base Penalty Amount associated with violations of Reliability Standards, the NERC Standards Committee Process Subcommittee has developed the 'Sanction Table' (Appendix A) to replace the Base Penalty Amount Table contained in Appendix 4B *Sanction Guidelines of the North American Electric Reliability Corporation* of the NERC Rules of Procedure.

The Sanction Table includes three sections, each addressing one of the three types of requirements: Operations, Cyber Security, and Planning. The base penalty range now correlates to the level of risk exposure to the BES based on the specific type of results-based requirement[1] which has been violated.

Each section identifies four levels of risk that equate to the potential degree of risk exposure to the BES and the likelihood of the violation resulting in BES instability, separation, or a cascading sequence of failures resulting from the violation of a requirement. The risk level is specific to the potential or actual risks associated with the category of Reliability Standard being evaluated.

The risk level is combined with the results-based requirement type (Performance-based, Risk-based, and Capability-based) where each type of requirement has a specific role in mitigating risk to the BES. This combination identifies a pre-defined base penalty range. The base penalty ranges identified in the Sanction Table were derived from the values that currently exist in the Base Penalty Amount Table and remain in alignment with the existing authority granted to NERC and the Regional Entities by Section 215 of the Energy Policy Act of 2005 (i.e., allows for the imposition of civil penalties of up to $1,000,000 per day per violation). This table would be used in the same manner as the existing Base Penalty Amount Table is today.

The Sanction Table recognizes that not every violation of a Reliability Standard requirement presents the same level of risk to the BES. By establishing a reasonable penalty range which takes into account the type of results-based requirement violated combined with the level of risk exposure to the BES, the table provides a similar starting point for assessing violations and allows for further analysis of the facts and circumstances of a violation, as is done today.

To preserve the relationship between the Reliability Standard and the enforcement process, the SDT will be required to identify the type (i.e., Operations, Cyber Security, or Planning) and the category (i.e., Performance-based, Risk-based, or Capability-based) for each requirement (For example: 'Operations – Performance-based). If an entity is found noncompliant, then the facts and circumstances associated with the finding of noncompliance would determine which

[1] Recommendation 4: Standard Product Issues identifies the use of results-based standards (RBS) in the standard development process, per Standards Process Input Group (SPIG) report titled: Recommendations To Improve the NERC Standards Development Process, dated April 2012.

penalty range would be used as the 'starting point' in determining the actual penalty or sanction.

The Sanction Table does not undermine the ultimate goals established by the VRF and VSL Guidelines. By basing the severity of violations on the potential or actual risk to the BES, the application of the Sanction Table supports the reliability of the BES by establishing a level of compliance that addresses risk to the BES as opposed to how badly a requirement was violated. Additionally, the Sanction Table will maintain the current uniformity and consistency in the determination of penalties by establishing an initial penalty range, consistent with the current ranges, based on the type of results-based requirement and the level of risk exposure to the BES created by the violation. Without the need to develop VRFs and VSLs, the SDT can focus primarily on the development of the appropriate results-based (performance-based, risk-based, or capability-based) requirements.

Example

To illustrate the difficulties associated with writing comprehensive VSLs, a review of Requirement 6 of EOP 005-2 System Restoration from Blackstart Resources is provided below:

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

Violation Severity Levels:

R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the sub-requirements.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the sub-requirements.	The Transmission Operator performed the verification but did not complete it within the five calendar year period.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification.

				OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the sub-requirements.

While the above VSLs may appear initially to cover a full range of possible violations, a closer inspection identifies several additional violations that are not clearly addressed in the VSLs, including:

- What is the VSL if the verification only covers some of the Cranking Paths?
- What is the VSL if the verification only covers some of the initial Loads?
- What is the VSL if the verification covered some but not all of the capabilities of the generation resources?
- What is the VSL if the verification covered each Blackstart resource's Real power but not Reactive Power?
- What is the VSL if the verification missed one of several Blackstart resources?

In real life, once the Compliance Enforcement Authority determines that there has been a violation of a requirement, the VRF and VSL will identify the starting point and then the "facts and circumstances" surrounding the violation are used, in conjunction to determine a penalty or sanction. The intersection of the VRF and VSL do not, by themselves, determine the size of a penalty or sanction.

As envisioned, rather than spending hours attempting to identify the full range of possible non-compliance, under the proposed system, the SDT would write the requirement and then would simply indentify the appropriate Time Horizon and the requirement type and category from the Sanction Table as shown below:

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Time Horizon = Long-term Planning] [Sanction Table: Planning - Capability-based]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

Summary

In conclusion, the Sanction Table bridges the span between the Standard Development Process and the enforcement of mandatory Reliability Standards and allows the ERO (NERC, Regional Entities, and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments. The Sanction Table provides a viable alternative to the current Base Penalty Amount Table and supports the SPIG recommendations to eliminate the VSLs from the essential elements of the Reliability Standard and to promote the development of results-based standards.

Sub-team 3 White Paper: Options for Handling 'No' Votes

This whitepaper addresses the SPIG recommendation regarding treatment of negative ballots for the purpose of achieving quorum and calculating industry consensus. The goal of these changes is to encourage stakeholders to submit constructive and focused comments that will enable drafting teams to effectuate positive, reliability-enhancing changes to proposed Reliability Standard. Negative ballots cast without comments, or with unrelated comments, ultimately result in excessive industry resources being utilized by drafting teams and such comments frustrate the ability to build consensus on proposed projects.

One of the principal recommendations of the SPIG relates to the continued accreditation of the NERC Standard Development Process by the American National Standards Institute (ANSI) and states:

> **Recommendation 1: American National Standards Institute**
>
> NERC should continue to meet the minimum requirements of the American National Standards Institute (ANSI) process to preserve ANSI accreditation.

In order to meet the minimum requirements of the ANSI process, all the fundamental tenets of the process must be met. Currently, the NERC Standards Development Process exceeds the minimum ANSI requirements in a number of areas. Two of these areas involve the treatment of Negative (No) ballots (ballots "rejecting" a standards-related item, both with and without comments):

1. The NERC Standards Development Process considers negative votes with comments (regardless of the nature of the comment or if the comment is even relative to the standard being balloted) in both the determination of quorum and in calculating industry consensus.

2. The NERC Standards Development Process considers negative votes without comments in the determination of quorum and in calculating industry consensus.

Section 2.7 of the ANSI Requirements[2] states:

> *Accredited Standards Developers shall record and consider all negative votes accompanied by any comments that are related to the proposal under consideration. This includes negative votes accompanied by comments concerning potential conflict or duplication of the draft standard with an existing American National Standard and negative votes accompanied by comments of a procedural or philosophical nature. These*

[2] ANSI Essential Requirements: Due process requirements for American National Standards, dated January 2012 (ANSI Requirements).

types of comments shall not be dismissed due to the fact that they do not necessarily provide alternative language or a specific remedy to the negative vote.

Accredited Standards Developers are not required to consider negative votes accompanied by comments not related to the proposal under consideration, or negative votes without comments. The ASD shall indicate conspicuously on the letter ballot that negative votes must be accompanied by comments related to the proposal and that votes unaccompanied by such comments will be recorded as "negative without comments" without further notice to the voter. If comments not related to the proposal are submitted with a negative vote, the comments shall be documented and considered in the same manner as submittal of a new proposal. If clear instruction is provided on the ballot, and a negative vote unaccompanied by comments related to the proposal is received notwithstanding, the vote may be counted as a "negative without comment" for the purposes of establishing a quorum and reporting to ANSI. However, such votes (i.e., negative vote without comment or negative vote accompanied by comments not related to the proposal) shall not be factored into the numerical requirements for consensus, unless the ASD's procedures state otherwise. The ASD is not required to solicit any comments from the negative voter. The ASD is not required to conduct a recirculation ballot of the negative vote. The ASD is required to report the "no" vote as a "negative without comment" when making their final submittal to the ANSI Board of Standards Review unless the ASD has been granted the authority to designate its standards as American National Standards without approval by the BSR.

As indicated above, ANSI requirements consider negative votes with comments related to the proposal under consideration in determining quorum and the calculation of industry consensus. However, ANSI requirements do not require the consideration of negative votes accompanied by comments that are not related to the proposal under consideration, or negative votes without comments in determining industry consensus. ANSI requirements allow for negative votes to be considered only in the calculation to determine quorum.

Issues

1. Should the NERC Standards Development Process only consider negative votes with related comments in the calculation to determine industry consensus?
2. Should the NERC Standards Development Process consider negative votes without any comments in the calculation to determine industry consensus?

Proposed Comment Criteria and Proposal

There are two proposed revisions to the Standards Process Manual related to the consideration of negative ballots.

First, it is proposed that negative votes must be submitted with comments that are *related* to the proposal under consideration. This includes clarifying comments or stated objections, comments of a procedural nature and comments concerning potential conflict or duplication of the draft Reliability Standard, Interpretation, Variance or definition with an existing Reliability Standard, Interpretation, Variance or definition. Comments should include guidance/input to

the drafting team that would assist efforts that would make revisions to the Reliability Standard acceptable and enable an affirmative vote in a subsequent ballot.

Second, negative ballots that contain no comments whatsoever, will not be counted for purposes of determining consensus. Such comments are inconsistent with NERC's consensus building process and provide no input to drafting teams and therefore add no value to the standards development process.

Both negative ballots with unrelated comments and negative ballots with no comments would be used in the calculation of quorum but would not be used in the calculation to determine consensus.

If a drafting team determines that a negative ballot has been submitted without a comment or with a comment that is unrelated to the proposal under consideration, the drafting team must submit its finding in writing to the Standards Process Manager within 30 calendar days of the closing of the comment period. The report will include the drafting team's rationale for each comment deemed to be invalid. If this finding is affirmed by the NERC Legal department, the Standards Process Manager will then provide the balloter an opportunity to provide additional comments. If the balloter does not provide related comments within 10 business days, the ballot results will be recalculated without the negative ballot. Each such balloter shall be informed of the appeals process contained within this manual. Where the outcome of the ballot result is affected by a negative ballot that is the subject of an appeal, the ballot results will not be considered final until the appeal is resolved pursuant to this manual.

This process provides a number of checks and balances to ensure that the determination of whether a comment is "related" to a proposal is carefully considered.

NERC's website is scheduled to be rebuilt and the page where ballots are cast will need to be revised. The above comment guidance and associated proposal should be clearly articulated so the entity casting the vote is fully aware that submission of helpful comments to the drafting team is critical to a successful stakeholder process for standards development. The NERC website should clearly indicate how votes are considered and counted towards consensus.
In conclusion, this proposed revision to the Standards Process Manual will conform to the minimum ANSI requirements in regards to the balloting criteria employed in the development of Reliability Standards. Further, recent revisions to the SPM have indicated that the early engagement of stakeholders in the development process produces higher quality Reliability Standards, and these revisions support this concept. The goal is to ensure that the drafting teams have the best opportunity to build consensus while still remaining responsive to the concerns raised by stakeholders.

Sub-team 4 White Paper: Cost Effective Analysis Process

Work on a Cost Effective Analysis Process (CEAP) was initiated before the SPIG recommendations were issued in response to concerns expressed by stakeholders and regulators in both the U.S. and Canada. The CEAP introduces the concept of cost consideration and effectiveness into the development of new and revised standards and affords the industry with opportunities to offer alternative methods to achieve the reliability objective of draft standards which may result in fewer implementation costs and resource expenditures. The draft CEAP was developed from the Northeast Power Coordinating Council (NPCC) regional CEAP, which was originally developed by NPCC in response to concerns raised by its regional Board of Directors regarding the need for standards development to consider potential cost impacts.

At the direction of the SC, the draft CEAP document was posted for a 60-day comment period, which will run through July 6, 2012. The SCPS will review comments received, incorporate pertinent comments into the CEAP, and align the document with the SPM revisions as necessary. Because this concept was developed before the SPM revisions, rather than developing a separate white paper on the topic, the sub-team has included the executive summary from the draft CEAP below. The full explanation of the CEAP process is available on the project page on NERC's website[3].

Executive Summary

The Federal Energy Regulatory Commission, NERC, and stakeholders have expressed keen interest in a process to determine effectiveness and implementation costs of proposed standards. During a 2010 FERC technical conference, the Commission recognized that "reliability does not come without cost," and significant interest was expressed in development of a process to identify costs for draft reliability standards and the ability of the proposed standards to achieve their reliability objective(s) in a cost effective manner. In addition, the NERC Board of Trustees (BOT), in its consideration of standards, has expressed concern regarding what a standard's implementation may cost the industry and the relevant incremental reliability improvement (benefits) that implementation of that standard may yield. This NERC Cost Effective Analysis Process (CEAP) represents an initial step towards addressing concerns regarding cost impacts (implementation, maintenance, and ongoing compliance resource requirements) associated with achieving reliability objectives identified in standards. The CEAP allows the industry the opportunity to identify alternative requirements for meeting a standard's reliability objective that may be less costly and equally as effective and efficient during the drafting process to help all in making informed choices. The approach described

[3] http://www.nerc.com/filez/standards/Cost_Effective_Analysis_Process.html

poses questions and provides aggregated results in the form of a report to the industry for informational purposes during balloting.

The CEAP introduces two assessments: one for feasibility, and another to determine the estimated industry wide cost impacts (implementation, maintenance, and ongoing compliance resource requirements) and potential reliability benefit of requirements in a proposed draft standard. "Cost impact," as used throughout the remainder of the document, is meant to include "implementation, maintenance, and ongoing compliance resource requirements, and reliability benefit." This will provide invaluable input into that standard's development process. The procedure, conducted in parallel with the drafting process, is crafted so it does not delay the development of the standard, but adds supporting information and background for the NERC stakeholders, ballot body, and the NERC Board of Trustees, to be utilized for decision making. In addition to providing a "snapshot" looking at an estimate of the cost impacts of the proposal, the CEAP will also solicit input from an independent and wider range of technical perspectives of the industry as well as NERC's technical groups to determine if any unintended adverse impacts may be created with respect to other Regional or Continent wide standards, should the draft standard be approved.

The CEAP will be utilized to perform an analysis of the cost impacts of the proposed requirements in NERC Reliability Standards as they are developed, and prior to their approval by the NERC Board of Trustees. Implementation of the CEAP will be coordinated with the steps outlined in the NERC SPM for developing a Reliability Standard.

The CEAP incorporates two separate phases of reviews. The first phase to be conducted is an estimated high level Cost Impact Analysis (CIA) that will be based on the responses to an initial set of questions posed to the industry during the Standard Authorization Request (SAR) stage, as part of the SAR posting, to determine if the standard project should be pursued. This Cost Impact Analysis is intended to be an assessment to determine the relative cost impacts (in orders of magnitude) of a particular proposed course of action. A comprehensive cost impact or benefit analysis is not being sought at this time. The focus of this effort is to obtain the information required to quantize the cost portion of the cost benefit equation. The "benefits" will be listed separately and may consist of either quantitative or qualitative information. Questions posed during the SAR stage to the industry will focus on probability and potential cost impacts. Questions posed during the SAR phase will also determine if the standard, in the view of stakeholders, would achieve an Adequate Level of Reliability (ALR), or go "beyond" what is considered adequate, to achieve some additional optimum or premium level of reliability as well as what "reliability risk" may be mitigated. Cost information collected in this phase will strictly be "order of magnitude costs" to determine if a proposed standard will have egregious costs associated with it.

Once this information is gathered and compiled by NERC staff, NERC staff will present it to the NERC Standards Committee (SC) for review, and the SC will make a determination whether or not to pursue the development of the standard. The CIA might lead to the conclusion that a technical guideline or white paper might be a preferred undertaking as opposed to a mandatory standard in a given area.

The second phase of the CEAP will be the Cost Effectiveness Assessment (CEA). The CEA may be considered a more detailed assessment whose purpose is to provide information about the relative effectiveness and cost impacts of different approaches to eliminating disparities, increasing life expectancy, or of any program or initiative. This will involve two sets of questions which will be asked concurrently. The first set is to solicit industry opinion on the technical feasibility and effectiveness to achieve the reliability objective of the standard with its requirements as well as possible alternatives. The second set of questions will be used to solicit cost impact, cost recovery, resource, and estimated time required with actions and facilities associated with the implementation of compliance with the draft standard. These ultimately should be done on a requirement by requirement basis, and questions will ideally be posted once the draft standard's requirements have been sufficiently solidified later in the standard development process.

The NERC Standards Staff will evaluate all information provided and produce a CEAP report that will be provided to the NERC SC for their endorsement, and to the standard drafting team for information. All of the cost impact information submitted by entities will be reviewed and compiled by NERC staff prior to being made public, or presented to the SC. Market sensitive issues of individual stakeholders may exist or be provided through the responses to the CEAP questions. Necessary confidentialities will be maintained, and no market sensitive information will be revealed. In addition, information in the final posted report will be based on the total number of respondents with due regard to regional reliability impacts. Upon approval, the report will be posted along with the NERC standard during balloting, or result in a remanded standard to be sent back to the standard drafting team with recommendations requiring further consideration along with potential issues for stakeholder consideration.

In the production of a final CEAP report, all available NERC resources will be utilized effectively and efficiently. If the industry responses were insufficient in the view of NERC staff when compiling the responses, efforts will be made to extrapolate without drawing conclusions, clearly identifying where this extrapolation may have been done in the final report. It must be emphasized that the purpose of the CEAP is not to provide additional obstacles to the NERC standard development process, but rather to inform stakeholders of proposed industry cost impact and provide an opportunity for suggestions of alternate methods to achieve equally effective reliability goals and objectives that may result in less cost. The final report is intended to be less analytical in nature and rather to promote better judgment and decision making.

Conclusion

Collectively, these changes to the SPM address the recommendations of the SPIG and identify ways to make best use of industry resources as the ERO develops technically sound standards in an efficient way. When it approved the draft SPIG recommendations in May, the BOT set December 31, 2012, as the deadline for filing the proposed SPM and ROP changes with FERC, and directed the SC to bring a proposed package of revisions to the standards process for its adoption in November. These revisions will require hard work from the industry over the next six months, but the result should be a process that stakeholders can agree is an improvement. If we can solicit good feedback now, we can ensure that we develop an excellent product as efficiently as possible, with wide industry support.

‘Operations’ Sanction Table

Type of Operations Requirement	Level 1 – a violation is not expected to adversely impact electrical state/capability of BES or ability to monitor/control BES.	Level 2 - a violation could directly and adversely impact electrical state/capability of BES or ability to monitor/control BES – unlikely to contribute to BES instability, separation, or a cascading sequence of failures.	Level 3 - a violation could contribute to impeding restoration, damaging equipment or non-consequential load loss or could contribute to BES instability, separation, or a cascading sequence of failures.	Level 4 – a violation could directly cause BES instability, separation, or a cascading sequence of failures.
Performance-based				
Such as but not limited to: • Perform action involving Elements and Facilities • Perform communications about Elements and Facilities • Set relays/coordinate relay settings • Perform maintenance • Implement a process, procedure, or plan • Develop ratings and	$3000 - $125000	$75000 - $300000	$15000 - $625000	$25000 - $1000000

limits				
Risk-based				
Such as but not limited to: • Develop an action plan • Conduct a study to support development of a process, procedure, or plan • Provide/distribute data, information, process, procedure, or plan • Verify/maintain/test a process, procedure, or plan	$2000 - $75000	$4000 - $200000	$6000 - $410000	$10000 - $675000
Capability-based				
Such as but not limited to: • Have a process, procedure, or plan • Verify that personnel authority exists • Verify that agreement exists • Verify personnel qualifications	$1000 - $30000	$2000 - $100000	$3000 - $200000	$5000 - $335000

• Verify Facility meets criteria • Verify accuracy of data				

'Cyber Security' Sanction Table

Type of Cyber Security Requirement	Level 1 – a violation could adversely affect Low Impact BES Cyber Systems; but would not be expected to expose the electrical state or the capability of the BES; or the ability to effectively monitor and control the BES.	Level 2 - a violation could adversely impact Medium Impact BES Cyber Systems; a violation could adversely expose the electrical state or the capability of the BES; or the ability to effectively monitor and control the BES - A violation of the requirement is unlikely to lead to BES instability, separation, or cascading failures.	Level 3 - a violation could adversely impact High Impact BES Cyber Systems; a violation could contribute to impeding restoration, damaging equipment or non-consequential load loss or could contribute to BES to instability, separation, or a cascading sequence of failures.	Level 4 – a violation could directly expose the BES to instability, separation, or a cascading sequence of failures.
Performance-based				
Such as but not limited to: • Act to protect cyber assets	$3000 - $125000	$75000 - $300000	$15000 - $625000	$25000 - $1000000

• Other				
Risk-based				
Such as but not limited to: • Implement a cyber security process, procedure, plan • Implement a cyber security program • Distribute a cyber security plan • Verify/maintain/test a cyber security process, procedure, plan	$2000 - $75000	$4000 - $200000	$6000 - $410000	$10000 - $675000
Capability-based				
Such as but not limited to: • Have a cyber security process, procedure, policy, or plan • Have a cyber security program • Provide education on cyber security • Verify qualifications of personnel • Categorize BES Cyber Systems and Assets	$1000 - $30000	$2000 - $100000	$3000 - $200000	$5000 - $335000

• Verify existence of authority • Verify that an agreement exists				

‘Planning’ Sanction Table

Type of Planning Requirement	Level 1 - a violation would not be expected to adversely affect the ability to assess the long-range reliability of the BES.	Level 2 - a violation could directly and adversely affect the ability to assess the long-range reliability of the BES .	Level 3 - a violation could contribute to development of a long-range plan that, if followed, could adversely affect the BES’ ability to respond to contingencies.	Level 4 - a violation could directly cause development of a long-range plan that, if followed, could adversely affect the BES’ ability to respond to contingencies.
Performance-based				
Such as but not limited to: • Conduct an analysis/assessments • Verify/maintain a model • Implement a methodology, process, procedure, or plan • Develop ratings or limits	$3000 - $125000	$75000 - $300000	$15000 - $625000	$25000 - $1000000
Risk-based				
Such as but not limited to:	$2000 - $75000	$4000 - $200000	$6000 - $410000	$10000 - $675000

• Have a model • Conduct a study to support development of a methodology, process, procedure, or plan • Provide/distribute data or information				
Capability-based				
Such as but not limited to: • Have a methodology, process, procedure, plan • Verify accuracy of data	$1000 - $30000	$2000 - $100000	$3000 - $200000	$5000 - $335000

‘Operations’ Sanctions Table

Type of Operations Requirement	Level 1 – a violation is not expected to adversely impact electrical state/capability of BES or ability to monitor/control BES.	Level 2 - a violation could directly and adversely impact electrical state/capability of BES or ability to monitor/control BES – unlikely to contribute to BES instability, separation, or a cascading sequence of failures.	Level 3 - a violation could contribute to impeding restoration, damaging equipment or non-consequential load loss or could contribute to BES instability, separation, or a cascading sequence of failures.	Level 4 – a violation could directly cause BES instability, separation, or a cascading sequence of failures.
Performance-based				
Such as but not limited to: • Perform action involving Elements and Facilities • Perform communications about Elements and Facilities • Set relays/coordinate relay settings • Perform maintenance • Implement a process, procedure, or plan • Develop ratings and limits	$3000 - $125000	$75000 - $300000	$15000 - $625000	$25000 - $1000000
Risk-based				
Such as but not limited to: • Develop an action plan • Conduct a study to support development of a process, procedure, or plan • Provide/distribute data, information, process, procedure, or plan • Verify/maintain/test a process, procedure, plan	$2000 - $75000	$4000 - $200000	$6000 - $410000	$10000 - $675000

Capability-based				
Such as but not limited to: • Have a process, procedure, or plan • Verify that personnel authority exists • Verify that agreement exists • Verify personnel qualifications • Verify Facility meets criteria • Verify accuracy of data	$1000 - $30000	$2000 - $100000	$3000 - $200000	$5000 - $335000

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Performance-based				
Such as but not limit to: • Conduct an analysis/assessment • Verify/maintain a model • Implement a methodology, process, procedure, or plan • Develop ratings or limits	$3000 - $125000	$75000 - $300000	$15000 - $625000	$25000 - $1000000
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Such as but not limit to: • Have a model • Conduct a study to support development of a methodology, process, procedure, or plan • Provide/distribute data or information	$2000 - $75000	$4000 - $200000	$6000 - $410000	$10000 - $675000
Capability-based				
Such as but not limit to: • Have a methodology, process, procedure plan • Verify accuracy of data	$1000 - $30000	$2000 - $100000	$3000 - $200000	$5000 - $335000

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Standards Committee Record of Email Ballot

At the June 14, 2012 meeting of the NERC Standards Committee, Chairman Allen Mosher called for an email ballot to authorize posting of proposed revisions to the Standard Processes Manual with ballots to be submitted by Monday, June 18, 2012. The announcement of the email ballot that was sent to the Standards Committee members is attached, and the record of the Standards Committee votes is included below.

The vote achieved a quorum with 19 of 21 Standards Committee members voting. Thirteen members voted to authorize posting, three members voted not to authorize posting, and three members abstained.

Chair **2012-2013**	Allen Mosher Senior Director of Policy Analysis and Reliability	Nonvoting		
Vice Chair **2012-2013**	P.S. (Ben) Li President	Nonvoting		
		Yes	**No**	**Abstain**
Segment 1-2011-12	Jason Shaver Manager – CIP Program Office		X	
Segment 1-2012-13	Carol A. Sedewitz Director, Transmission Planning	X		
Segment 2-2011-12	Al DiCaprio Senior Strategist	X		
Segment 2-2012-13	H. Steven Myers Principal, Operating & Planning Standards	X		
Segment 3-2011-12	Ronald G. Parsons Manager, Transmission Interconnections and Operations		X	
Segment 3-2012-13	John Bussman Manager Reliability Compliance		X	
Segment 4-2011-12	Joseph Tarantino Regulatory Compliance Coordinator			X

Segment 4-2012-13	Frank Gaffney Assistant General Manager of and Officer of Regulatory Compliance	X		
Segment 5-2011-12	Gary Kruempel Compliance Director, Energy Supply	X		
Segment 5-2012-13	Scott Miller Manager, Corporate Affairs	X		
Segment 6-2011-12	Silvia Parada Mitchell Director, NERC Reliability Standards & Compliance			X
Segment 6-2012-13	Alice Murdock Ireland Reliability Standard Analyst			
Segment 7-2011-12	John A. Anderson President & CEO	X		
Segment 7-2012-13	Frank McElvain Senior Consulting Manager	X		
Segment 8-2011-12	Michael Goggin Manager of Transmission Policy	X		
Segment 8-2012-13	Frederick Plett Utility Analyst			
Segment 9-2011-12	Diane J. Barney Planning Engineer	X		
Segment 9-2012-13	Klaus Lambeck Chief Facilities, Siting and Environmental Analysis	X		
Segment 10-2011-12	Steve Rueckert Director of Standards	X		
Segment 10-2012-13	Linda Campbell Vice President and Executive Director, Standards and Compliance	X		
Canada 2012	David Kiguel Manager, Reliability Standards			X

From: Goodman, Kathleen
To: rscmembers
Subject: Standards Process Manual changes - draft comments
Date: Friday, July 13, 2012 5:06:44 PM

For discussion/consideration:

One item not included but needing further discussion is the comment forms being provided to the industry on all NERC activities. All the comments forms seem to be stated as "we made this change. Do you agree with this change?" An opportunity for back-and-forth is not being provided to the industry with these types of comment forms but I am struggling with who/what "body" to approach with this issue. See below for big ticket comments:

1. Section 16 is a new section giving the SC authority to "waiver" the process steps. I do not support giving the SC this authority, thereby removing the requirement to report deviations of the process. I believe the SC already takes an exceptional amount of liberty with their "authority"
2. The section on "variances" implies that a variance is needed for "a conflict with an approved tariff" but I thought Standards were not allowed to be developed under such scenarios?
3. NERC and the SC *had taken the position* that the BOT action had limited Interpretations to the Requirements. However, upon further inquiry regarding the Level 1 appeal for the NWPP FRI on BAL-002, the BOT instructed that their *action had been too strictly interpreted and that their action did not limit things contained within the "four corners" of the Standard.*

   However, even after this clarification, as I look through the SPM changes, there continues to be this egregious attempt to limit the Industry's ability to request an appropriate Interpretation and, therefore, stay off inappropriate enforcement. The specifics of this are in the Interpretation section, the SPM indicates that an RFI should be rejected if (1) an issue can be addressed by an active standards development activity; (2) RFI request clarity on any items other than a Requirement; and (3) an RFI has already been addressed in the "record." I am not supportive of these and actually believe the (2) and (3) completely contradict one another.
4. There remains language allowing for "waivers" of enforceable requirements for field trial purposes. Since the enforceable requirements are essentially backed by law, I question the SC and BOT authority to enact such "waivers."
5. Section 4.18 proposes to give the SC additional authority to "withdraw" Standards, Interpretations, Definitions for "good cause" once the Standards, Interpretations, or Definitions has already been approved by industry and the BOT. See item 1 above.
6. I cannot figure out how abstentions are accounted for in either the quorum or

approval calculations. There seems to be no purpose for abstaining anymore.

7. Balloting: the BB has 10 CALENDAR days to vote; however, if a balloter votes NO without providing appropriate comments they will be contacted to enable them to provide appropriate comments for their NO vote to count and they will have 10 BUSINESS days. I think both should by business days.
8. The process of opening a solicitation every year seeking ideas for new Standards Development proposals should be stopped. We are already inundated with Standards Development activities and anyone can submit a SAR at any time.
9. There is a new paragraph "slipped in" to the Interpretation Section (7.0), that appears to give NERC staff authority to continue to not process Interpretations after the BB approves them. It states, "The NERC Reliability Standards and Legal staffs shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Reliability Standards and Legal staffs shall make a recommendation to the NERC Board of Trustees regarding adoption."

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Herb Schrayshuen
Vice President, Standards and Training

June 20, 2012

Dear Regional Entity Managers Group and Regional Standards Group Members,

On June 20, 2012, proposed revisions to the NERC Standard Processes Manual (SPM) to implement the Standard Process Input Group's (SPIG) recommendations will be posted for a 30-day comment period through July 19, 2012. These revisions aim to improve the standard development process so that the Electric Reliability Organization (ERO) is able to develop technically sound standards in a more efficient way that makes better use of industry resources. The next six months will require hard work of industry stakeholders, and I'm reaching out to you now so that we can work together to identify the best ways for NERC staff and the Standards Committee (SC) to reach out to stakeholders within your regions to explain the project and identify any concerns as early as possible.

Below, I've included detailed information to get you up to speed on the background of this project, and then I've explained how you can help as the project moves forward. When the opening of the first comment period is announced, the SPM revisions, background information, and a detailed schedule of next steps will be posted to the project page.

Background

At its February 9, 2012 meeting, the NERC Board of Trustees (BOT) requested the assistance of the NERC Member Representatives Committee (MRC) to provide policy input, and a proposed framework, for specific improvements to the standards development process. The MRC Chair and Vice Chair invited several members of the MRC, two NERC BOT members, the NERC CEO, and the SC Chair – the group collectively known as the SPIG – to join with them as participants in developing recommendations to improve the standards development process in the following key areas:

- Clarity on the reliability objectives, technical parameters, scope, and the relative priority of the standards project
- The drafting process (developing the specific technical content of the standard)
- Standards project management and workflow
- Formal balloting and commenting

To help ensure that the SPIG focused its efforts on the most important areas for improvement, the group began its work by gathering input from subject matter experts, including the regions, the MRC, standard drafting team leaders, NERC staff, and other stakeholders. This input was collected through a series of interviews, supplemented by a formal survey.

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Based on that input, the SPIG produced a document with five recommendations to modify the way NERC develops Reliability Standards and other solutions intended to improve the priority, product, and process of standards development:

1. **American National Standards Institute (ANSI):** NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.
2. **Reliability Issues Steering Committee (RISC):** The NERC BOT is encouraged to form a RISC to conduct front-end, high-level reviews of nominated reliability issues and direct the initiation of standards projects or other solutions that will address the reliability issues.
3. **Interface with Regulatory and Governmental Authorities:** The NERC BOT is encouraged to task NERC management, working with a broad array of ERO resources (e.g., the MRC, technical committees, Regional Entities, trade associations, etc.) to develop a strategy for improving the communication and awareness of effective reliability risk controls to increase input and alignment with state, federal, and provincial authorities.
4. **Standards Product Issues:** The NERC BOT is encouraged to require that the standards development process address the use of results-based standards; cost effectiveness of standards and standards development; alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and the retirement of standards no longer needed to meet an adequate level of reliability.
5. **Standards Development Process and Resource Issues:** The NERC BOT is encouraged to require the standards development process to be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The BOT is also encouraged to require standard development resources to achieve and address formal and consistent project management and efficient formation and composition of standard drafting teams.

The recommendations also aim to strengthen consensus building, first on the need for a standard, and then on the requirements themselves.

These recommendations were presented to the BOT and approved on May 9, 2012, and the SC was specifically charged with addressing SPIG Recommendations 1, 4, and 5. The SC has organized this effort by leveraging each of its subcommittees, the Process Subcommittee (SCPS) and the Communications and Planning Subcommittee (SCCPS), to work in parallel on developing proposed revisions and conducting outreach to industry stakeholders to ensure that all interested stakeholders have an opportunity to provide their input.

Since May 2012, subteams of the SCPS, supported by NERC standards and legal staff, have developed proposed revisions to the SPM and associated changes to Section 300 of NERC's Rules of Procedure (ROP). These subteams have focused on changes in the following categories:

- Subteam 1: Analysis of ANSI requirements and streamlining commenting and balloting
- Subteam 2: Essential elements of a standard (elimination of measures, Violation Risk Factors, and Violation Severity Levels)
- Subteam 3: Options for handling 'no' votes to ensure drafting teams have the information they need to perform their work
- Subteam 4: Cost Effective Analysis Process (CEAP)

The proposed revisions from these subteams will be included in the posted redline version of the SPM, and the SCPS is looking forward to industry feedback on its work.

An oversight team composed of SC leadership and NERC standards and legal staff is managing the project. This group has reviewed all proposed changes from the subteams and will coordinate the schedule of postings, SC materials for approval, and BOT materials for approval.

Separate but related projects are already in progress to implement aspects of the SPIG recommendations that do not require changes to the SPM. These include efforts to develop a CEAP and train drafting teams to have a role in developing RSAWs.

How You Can Help

Clear communication and transparency will be invaluable when it comes to the success of this project. NERC staff and the SC want support for the revisions to the SPM and the concepts behind them, but at this stage, more than that, the goal is to identify any issues or concerns early on. If we can solicit good feedback now, we can ensure that we develop an excellent product as efficiently as possible, with wide industry support.

To that end, the SCCPS has already identified some outreach opportunities with certain regions. For instance, an SCPS member will be presenting on the new process at the TRE Reliability Standards Committee Meeting on June 26, 2012, and an SCCPS member will offering remarks at the Mid-Continent Compliance Forum on June 27, 2012. If you have ideas for similar outreach opportunities with your regions, please let us know; we have developed a slide deck that can be modified and used at events in the next month, and we would be happy to arrange for an SC member, SC subcommittee member, or NERC staff member to speak during any upcoming events you have in mind.

Next Steps

When it approved the draft SPIG recommendations in May 2012, the BOT set December 31, 2012 as the deadline for filing the proposed SPM and ROP changes with FERC, and directed the SC to bring a proposed package of revisions to the standards process for its adoption in November 2012. After the comment period closes on July 19, 2012, a comment report will be circulated and the SCPS and its subteams will revise the SPM and associated documents accordingly. The SPM and ROP changes will then be posted for a 45-day formal comment period and initial ballot in August 2012, revised according to comments, and, ideally, be posted for a 10-day recirculation ballot in October 2012. The documents will then be presented to the NERC BOT and prepared for filing.

For additional information, please reference the Key Dates and Milestones document on the project page.

I look forward to working with you over the next several months to make this project a success. If you have any questions, please don't hesitate to contact me.

Sincerely,



Herb Schrayshuen
Vice President, Standards and Training

cc: Mr. Gerry Cauley, President and CEO, NERC
Ms. Laura Hussey, Standards Process Manager , NERC

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Standards Announcement

NERC Standard Processes Manual Revisions to Implement SPIG Recommendations Posted for a 30-day Stakeholder Comment Period: June 20, 2012 – July 19, 2012

Now Available

Proposed revisions to the NERC Standard Processes Manual (SPM) to implement the Standard Process Input Group's (SPIG) recommendations have been posted for a 30-day comment period through July 19, 2012. To support the revisions, explanatory text boxes have been included within the revised SPM, and a white paper and the original SPIG recommendations have also been posted for additional background information and rationale.

Instructions for Commenting

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

When it approved the draft SPIG recommendations in May, the NERC Board of Trustees (BOT) set December 31, 2012 as the deadline for filing the proposed SPM and associated Rules of Procedure (ROP) changes with FERC, and directed the Standards Committee (SC) to bring a proposed package of revisions to the standards process for its adoption in November. After the comment period closes on July 19, 2012, a comment report will be circulated and the SC Process Subcommittee (SCPS) and its sub-teams will revise the SPM and associated documents accordingly. The SPM and ROP changes will then be posted for a 45-day formal comment period and initial ballot in August, 2012, revised according to comments, and, ideally, be posted for a 10-day recirculation ballot in October, 2012. The documents will then be presented to the NERC BOT and prepared for filing.

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- Clarity on the reliability objectives, technical parameters, scope, and the relative priority of the standards project
- The drafting process (developing the specific technical content of the standard)

- Standards project management and workflow
- Formal balloting and commenting

To help ensure that the SPIG focused its efforts on the most important areas for improvement, the group began its work by gathering input from subject matter experts, including the regions, the MRC, standard drafting team leaders, NERC staff, and other stakeholders. This input was collected through a series of interviews, supplemented by a formal survey.

Based on that input, the SPIG produced a document with five recommendations to modify the way NERC develops Reliability Standards and other solutions intended to improve the priority, product, and process of standards development:

1. **American National Standards Institute (ANSI):** NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.
2. **Reliability Issues Steering Committee (RISC):** The NERC BOT is encouraged to form a RISC to conduct front-end, high-level reviews of nominated reliability issues and direct the initiation of standards projects or other solutions that will address the reliability issues.
3. **Interface with Regulatory and Governmental Authorities:** The NERC BOT is encouraged to task NERC management, working with a broad array of Electric Reliability Organization resources (e.g., the MRC, technical committees, Regional Entities, trade associations, etc.) to develop a strategy for improving the communication and awareness of effective reliability risk controls to increase input and alignment with state, federal, and provincial authorities.
4. **Standards Product Issues:** The NERC BOT is encouraged to require that the standards development process address the use of results-based standards; cost effectiveness of standards and standards development; alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and the retirement of standards no longer needed to meet an adequate level of reliability.
5. **Standards Development Process and Resource Issues:** The NERC BOT is encouraged to require the standards development process to be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The BOT is also encouraged to require standard development resources to achieve and address formal and consistent project management and efficient formation and composition of standard drafting teams.

The recommendations also aim to strengthen consensus building, first on the need for a standard, and then on the requirements themselves. Further detail is available in the posted SPIG report.

These recommendations were presented to the BOT and approved on May 9, 2012. The SC was specifically charged with addressing SPIG Recommendations 1, 4, and 5. The SC has organized this effort by leveraging

each of its subcommittees, the Process Subcommittee (SCPS) and the Communications and Planning Subcommittee (SCCPS), to work in parallel on developing proposed revisions and conducting outreach to industry stakeholders to ensure that all interested stakeholders have an opportunity to provide their input.

Since May, sub-teams of the SCPS, supported by NERC standards and legal staff, have developed proposed revisions to the SPM and associated changes to Section 300 of NERC's Rules of Procedure (ROP). These sub-teams have focused on changes in the following categories:

- Sub-team 1: Analysis of ANSI requirements and streamlining commenting and balloting
- Sub-team 2: RSAWs and essential elements of a standard
- Sub-team 3: Options for handling 'no' votes to ensure drafting teams have the information they need to perform their work
- Sub-team 4: Cost Effective Analysis Process

The proposed revisions from these sub-teams are included in the posted redline version of the SPM, and the SCPS is looking forward to industry feedback on its work.

An oversight team composed of SC leadership and NERC standards and legal staff is managing the project. This group has reviewed all proposed changes from the sub-teams and will coordinate the schedule of postings, SC materials for approval, and BOT materials for approval.

Separate but related projects are already in progress to implement aspects of the SPIG recommendations that do not require changes to the SPM. These include efforts to develop a Cost Effective Analysis Process (CEAP) and train drafting teams to have a role in developing RSAWs.

The next six months will require hard work of industry stakeholders – both the SC and its subcommittees, as well as those participating in these process revisions by offering formal and informal comments – but the result will be a more efficient process that produces sound, technically excellent standards in a way that makes better use of limited industry resources.

Additional documentation is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, at monica.benson@nerc.net.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Recommendations to Improve the NERC Standards Development Process

Member Representatives Committee (MRC)
Standards Process Input Group (SPIG)

Draft — April 2012

RELIABILITY | ACCOUNTABILITY






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Preface

Formation of the Standards Process Input Group

At its February 9, 2012 meeting, the NERC Board of Trustees (BOT) requested the assistance of the NERC Member Representatives Committee (MRC) to provide policy input, and a proposed framework, for specific improvements needed to the standards development process. The MRC Chair and Vice Chair invited several members of the MRC, two NERC Board of Trustees members, the NERC CEO, and the Standards Committee (SC) Chair to join with them as participants in the Standards Process Input Group (SPIG) in developing recommendations to improve the standards development process in the following areas:

- Clarity on the reliability objectives, technical parameters, scope, and the relative priority of the standards project.
- The drafting process (developing the specific technical content of the standard).
- Standards project management and workflow.
- Formal balloting and commenting.

To help ensure that the SPIG focused its efforts on the best areas for improvement, they began their process by gathering input from subject matter experts (SMEs), including the regions, MRC, Standard Drafting Team leaders, NERC staff, and other stakeholders by asking the following:

- What are the issues that are keeping the process from improving the reliability benefits of the standards?
- What are the impediments to improving the efficiency of completing a new standard or standard revision?
- Are stakeholder resources being used efficiently? If not, then why?

SPIG Timeline for Input

- Trades input was provided to NERC BOT in January 2012
- Outreach Survey comments received from 105 stakeholders in late February
- SPIG conference call with FERC staff and initial SPIG planning meeting conducted in early March
- SPIG provides preliminary report to MRC for input in early April
- Input from MRC received by April 13
- Additional SPIG planning meeting to consider MRC input conducted April 19-20
- Report revised, finalized, and posted with MRC agenda on April 25
- MRC discussion at MRC meeting on May 8
- Final report to NERC BOT in late May

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Executive Summary

The Standards Process Input Group (SPIG) organized by the NERC Member Representatives Committee (MRC) is proposing in this report a number of changes to the way NERC develops Reliability Standards and other solutions intended to improve the priority, product and process of standards development. Inherent in these proposed changes is an effort to better understand, articulate and incorporate, into the standards development process, the appropriate accountabilities for standards development.

For example, Section 215 of the Federal Power Act creates accountability for the Federal Energy Regulatory Commission (FERC), first to certify an Electric Reliability Organization (ERO) for the purpose of establishing and enforcing reliability standards for the bulk power system, and then to approve the standards developed by the ERO. As such, FERC is accountable to the U.S. Congress, which passed the law that created Section 215.

Section 215 also creates accountability for NERC by requiring that the ERO, certified by FERC, have a demonstrated ability to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system. This accountability extends to the NERC management to see that high quality standards are developed in an efficient and effective way and to the NERC Board of Trustees (Board) that must approve those standards before they are filed with governmental regulatory authorities in the U.S. and Canada.

Finally, the stakeholders, whose technical expertise is essential to the development of the standards, have a shared accountability with NERC and with each other to see that the right standards are developed in a fair, open, balanced and inclusive way.

One of the principal recommendations of the SPIG, is the creation of a Reliability Issues Steering Committee (RISC) that is intended to address these issues of accountability by ensuring that NERC develops the right standards, in the right way, and in a timely and efficient manner. To accomplish this, the RISC will conduct front-end, high level review of nominated reliability issues and direct the initiation of standards projects or other solutions that will address the reliability issues.

In addition to recommending the creation of the RISC, the SPIG also recommends that Reliability Standards Audit Worksheets (RSAWs) be developed concurrent with their associated standards and posted along with those standards for comment. The purpose here is to make sure that the RSAWs are aligned with the intent and wording of the standards to reduce the need for Interpretations and Compliance Application Notices.

Lastly, the SPIG is recommending a redesign of the composition and process used by Standards Drafting Teams to make more efficient and effective use of the subject matter expertise resident in the industry, and to provide those experts with additional support resources in terms of project management and facilitation, legal expertise, and technical writing support.

The recommendations also aim to strengthen consensus building, first on the need for a standard and then on the requirements themselves.

Collectively, these recommendations suggest a major revision of how decisions to develop standards are determined in the first place and, once the decision is made that a new or revised standard is needed, to see that it is developed in the most efficient, effective, and timely way, taking into account throughout the process the costs, benefits and justification for all standards.

Introduction

Priority, product and process are the three main focus areas addressed by the recommendations of the SPIG regarding their review and analysis of the NERC standards development process.

The SPIG provides five recommendations designed for action and for discussion. The analysis of feedback received throughout this project indicates that more discussion should occur around the variety of the changes, improvements, and implementation being proposed in these recommendations, as listed below and described in more detail in this report.

Recommendation 1: American National Standards Institute — NERC should continue to meet the minimum requirements of the American National Standards Institute (ANSI) process to preserve ANSI accreditation.

Recommendation 2: Reliability Issues Steering Committee — The NERC Board is encouraged to form a Reliability Issues Steering Committee (RISC) to conduct front-end, high level review of nominated reliability issues and direct the initiation of standards projects or other solutions that will address the reliability issues.

Recommendation 3: Interface with Regulatory and Governmental Authorities — The NERC Board is encouraged to task NERC management, working with a broad array of ERO resources (e.g., MRC, technical committees, Regional Entities, trade associations, etc.) to develop a strategy for improving the communication and awareness of effective reliability risk controls which increases input and alignment with state, federal, and provincial authorities.

Recommendation 4: Standards Product Issues — The NERC board is encouraged to require that the standards development process address:

- The use of results–based standards (RBS);
- Cost effectiveness of standards and standards development;
- Alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and
- The retirement of standards no longer needed to meet an adequate level of reliability.

Recommendation 5: Standards Development Process and Resource Issues — The NERC Board is encouraged to require the standards development process to be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The Board is also encouraged to require standard development resources to achieve and address:

- Formal and consistent project management; and
- Efficient formation and composition of Standard Drafting Teams (SDTs).

These recommendations were derived from a synthesis of stakeholder responses categorized into the following three concentrated areas:

I. ANSI: Accreditation

- Preserve ANSI accreditation in order to ensure openness, transparency, consensus building, balance of interests and due process
- Ensure checks and balances of the ANSI process
- Limit application of requirements that can hinder progress
- Limit negative ballots without comment
- Consider other options if ANSI prevents efficiency gains

II. PRODUCT: Quality of Standards

- Consider the cost effectiveness (limited value justification)
- Improve clarity in terms of the reliability objective and benefit
- Ensure auditability
- Improve supporting documentation or administrative records
- Improve registered entity and auditor understanding
- Involve industry, NERC and FERC in the quality review earlier in the standards development process
- Seek clarity and technical justification upfront
- Be sensitive not to gear towards compliance risk rather than reliability risk

III. PROCESS: Efficiency, Timeliness and Effectiveness

- Address the SDT composition (need expertise in legal, technical writing, compliance, etc.)
- Improve timeliness and effectiveness in terms of commenting/balloting (need to consider the manual effort and timing associated with posting, grouping and responding)
- Manage the number of standards coming through the process at the same time (to ensure the right number can be processed efficiently)
- Seek convergence on consensus (to avoid taking too long to achieve)
- Improve efficiencies (to avoid taking too long)
- Implement a project manager and facilitator (need within the SDT and the back office of NERC)
- Improve communications and coordination between industry, NERC and FERC staff; especially in terms of the compliance/enforcement process

Recommendations from the SPIG

Recommendation 1: American National Standards Institute

Issue

Should NERC continue using the American National Standards Institute (ANSI) process for developing standards?

Recommendation

NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.

Background

The SPIG's initial survey of the industry asked "How important are ANSI accreditation and ANSI principles (openness, transparency, consensus-building, fair balance of interests, and due process) to the NERC standards development process?" The majority of responses agreed that NERC standards development process should continue to at least meet the minimum ANSI requirements (Figure 1).

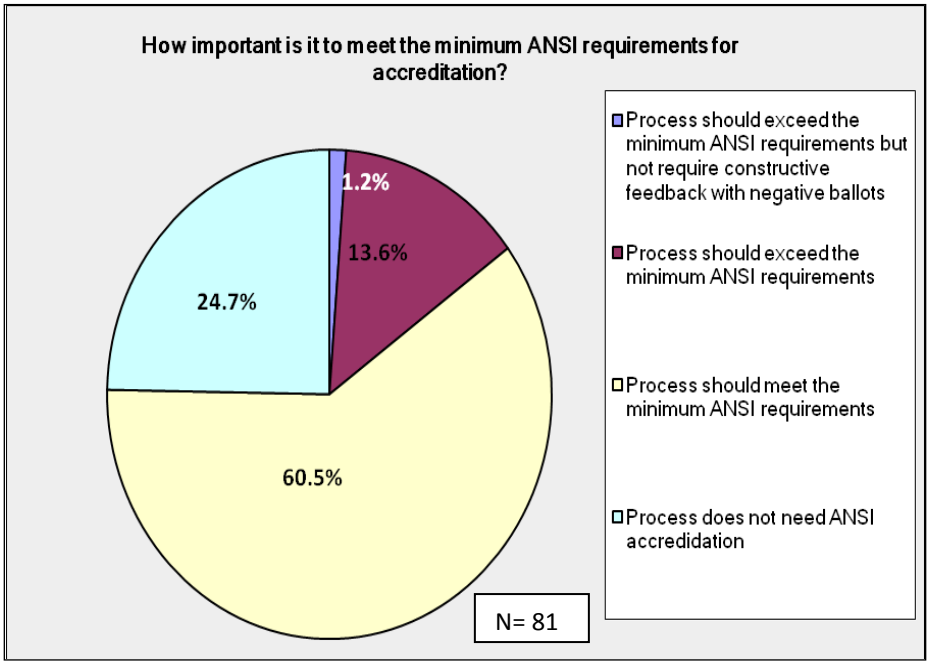


Figure 1: Results from SPIG survey of the Industry, April 2012

According to ANSI, accreditation signifies the standards developer is committed to an open, fair and time-tested consensus process that benefits stakeholders. Developers are accredited to the requirements contained in the *ANSI Essential Requirements: Due Process Requirements for American National Standards*. NERC staff confirms that the current standards process meets and in some cases exceeds the ANSI Essential Requirements.

Recommendation 2: Reliability Issues Steering Committee (RISC)

Issue

How should NERC determine:

- What actions are needed to address identified risks to reliability?
- Whether the development of a standard is necessary and its cost/benefit to reliability is justified?
- What should be the priority and timeline for standards development?

Recommendation

The Board is encouraged to form a Reliability Issues Steering Committee (RISC) to conduct front-end, high level review of nominated reliability issues and direct the initiation of standards projects or other solutions that will address the reliability issues.

Proposed Details

The RISC would:

- Be comprised of stakeholders including, but not limited to:
  - Chairs and vice chairs of the technical committees;
  - Select MRC members and other stakeholders;
  - Chair, approved by the Board; and
  - NERC Senior Staff member.
- Utilize a broad range of industry and other expertise.
- Analyze performance gaps, technical viability, reliability benefit, cost impact/ justification, clarity of standard's scope, etc.
- Advise the Board on key initiatives and priorities; recommends standards projects or alternatives (Figure 2).
- Report directly to Board (and not the MRC).
- Require Board review and approval of any significant new ERO initiatives or reordering of ERO strategic priorities.
- Not supersede the role of Standards Committee.
- Set milestones and timelines for standards projects.
- Conform to NERC Bylaws and Rules of Procedure.

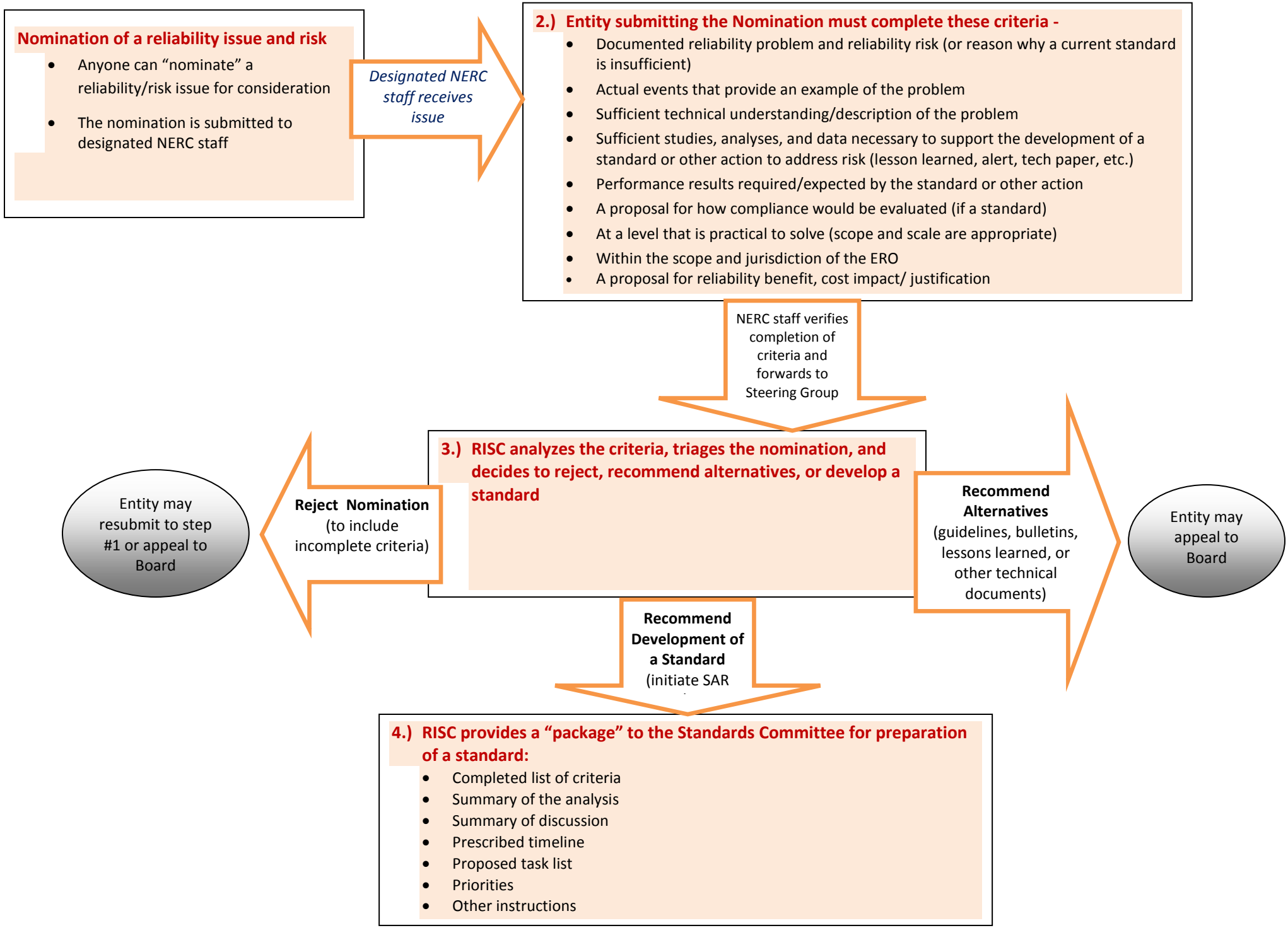
Additional Issues to be Addressed (per the Board's Discretion) During the Implementation Phase

- Role of the RISC in three-year reliability SDP.
- Modification to existing standards including elimination of duplicative or low value standards.
- Role of RISC with respect to FERC directives.
- Communication between the RISC, Standards Committee (SC), Standards Oversight and Technology Committee, MRC and Board and its technical committees.
- Relationship with governmental authorities.

Explanation of Figure 2: Proposed Front-End Process Flow Chart

- Anyone can "nominate" a reliability/risk issue, via designated NERC staff, for consideration by the RISC. Upon verification and satisfactory completion of the nomination criteria, the RISC may decide to:
  1. Reject the nomination;
  2. Recommend alternative action other than standards; or,
  3. Develop a standard.
- If the nomination is rejected by the RISC, an appeals process will be available.
- Recommended alternatives to standards may include the development of guidelines, bulletins, alerts, lessons learned, best practices, technical documents, etc. If a standard is recommended, a project management "package" will be prepared by the RISC for the SC, including (as appropriate):
  - The completed list of criteria
  - Analysis of performance gaps, technical viability, reliability benefit, cost impact/ justification, clarity of standard's scope, etc.
  - Discussion
  - Timeline
  - Task list
  - Priorities
  - Other instructions
- The RISC may refer a "package" to the SC with instructions to prepare a standard. The RISC should also inform the MRC and Board of its actions.

Figure 2: Proposed Front-End Process Flowchart (pathway for the Reliability Issues Steering Committee – RISC)



Recommendation 3: Interface with Regulatory and Governmental Authorities

Issue

How can NERC improve the communication and awareness of NERC's strategic initiatives on major risks to reliability to increase alignment of NERC with the concerns of state, federal, and provincial authorities?

Recommendation

The Board is encouraged to task NERC management, working with a broad array of ERO resources (e.g., MRC, technical committees, Regional Entities, trade associations, etc.) to develop a strategy for improving the communication and awareness of effective reliability risk controls which increases input and alignment with state, federal, and provincial authorities.

Proposed Details

- Interface with governmental authorities to align priorities and timing of reliability initiatives. Establish and align priorities early on during the nomination of the reliability issue.
- Develop methods to effectively communicate progress and manage expectations.
- Promote effective rules of engagement of state, federal, and provincial regulatory staff in accordance with jurisdictional requirements.
- Following successful ballot of standard and approval by the Board, pre-filing meetings will be held with FERC staff and individual Commissioners to help ensure FERC approval without conditions; and similar efforts will apply with governmental authorities in Canada.

Additional Issues to be Addressed (per the Board's Discretion) During the Implementation Phase

- Responsibility for managing the details above, concerning progress and expectations.
- Encourage regulatory authorities to permit staff to submit written comments to the drafting team during informal and formal comment periods.

Background

The SPIG provides as additional reference and guidance the *Roles and Responsibilities: Standards Drafting Team Activities*, approved by the SC in July 2011, includes the following policy guidance, approved by the NERC Board at its October 29, 2008 meeting, to guide standard drafting teams' responses to regulatory authority staff involvement in standard drafting activities:

a. The standard drafting team has sole responsibility for drafting and approving the language in the proposed standards that are presented to the SC for ballot.

b. NERC and the SC support the involvement of regulatory authority staff in all standards drafting team activities, where permitted by law.

c. NERC recognizes that regulatory authority staff does not speak for the regulatory authority itself and, as such, the input they provide is considered advice.

d. In the event regulatory authority staff does choose to participate in drafting team activities, they should be treated as any non-voting observer or participant.

e. Standard drafting team members should seek out the opinion of regulatory authority staff, consider the regulatory staff input on its technical merits, and respond to written comments offered during a public posting period as it would seek opinions from, consider the technical merits of, and respond to comments offered by other industry stakeholders.

f. To the extent that regulatory authority staff advice is offered to the drafting team (or members thereof) in a forum that is not public and open to all industry participants, the standard drafting team should consider the input as advice.

g. If the team chooses to act on regulatory authority staff advice offered in a non public forum, the standard drafting team chair should either:

   - Request the regulatory authority staff to provide the advice during an open meeting or conference call of the drafting team; or,
   - Document his/her understanding of the issues or advice presented, and include the information in an open industry comment period with the accompanying changes to the proposed standards.

Recommendation 4: Standards Product

Issue
How will standards be developed to effectively achieve reliability objectives through clear, high quality Results-Based Standards (RBS) requirements in a cost effective manner?

Recommendation:
The Board is encouraged to require that the standards development process address:

- ***The use of RBS;***
- ***Cost effectiveness of standards and standards development;***
- ***Alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and***
- ***The retirement of standards that are no longer needed to meet an adequate level of reliability.***

Proposed Details

- Utilize RBS model as the basis for all standards.
  i. Evaluate all existing standards and revise to meet format of RBS.
  ii. Retire any existing standards that are not chosen to be modified into a RBS format per Board approval.
  iii. Develop all new standards in RBS format.
- Ensure cost effectiveness of standards through documentation of alternatives analysis.
- Include cost impact/reliability benefit analysis in the final standards package posted for ballot.
- Ensure clarity on reliability objectives and compliance obligations.
  i. SDT is responsible for the development of the standard including requirements and measures.
  ii. Compliance staff will develop RSAWs (that will be used in the auditing of compliance) in conjunction and coincident with the development of the standard.
  iii. Post entire package for stakeholder comment, including standards and RSAWs (RSAWs are not balloted).
  iv. Changes to RSAWS after the ballot body develops measure/standard require Board approval.
- Revise Essential Elements of the Standards Template to eliminate redundancies such as Violation Severity Levels (VSLs).
- Consider "applicability" provisions and criteria for those most impacted by implementing a standard.

Additional Issues to be Addressed (per the Board's Discretion) During the Implementation Phase

- Establish process to consider elimination of standards and standards requirements that have minimal value.
    i. The recent FERC Find, Fix, Track and Report (FFTR) Order encourages the reduction of unnecessary requirements and a structured process needs to be developed to achieve this.
    ii. Additional options may include a task to the RISC, Operating Committee, or Planning Committee, as determined by the Board.

Recommendation 5: Standards Development Process and Resources

Issue

How can the existing standards development process be improved upon and streamlined and how can resources be better utilized to ensure effective, efficient, and expeditious standards development?

Recommendation

The Board is encouraged to require the standards development process be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The Board is also encouraged to require standard development resources to achieve and address:

- ***Formal and consistent project management***
- ***Efficient formation and composition of SDTs***

Proposed Details

- The drafting team will post responses to each comment received during the *final,* formal comment period prior to the recirculation ballot. For other postings, there is no ANSI requirement to post responses to the comments.
- Modify the comment process to:
  i. Bundle responses to comments.
  ii. SDT will post draft standard for informal comment period of 30 days, but not be required to respond to comments.
  iii. Promote an automated system for managing comments.
  iv. Conduct industry webinars between successive ballots to enhance understanding of issues and facilitate consensus.
  v. Facilitate consensus by encouraging industry collaboration and submittal of coordinated comments through Regional Entities and trade groups.
- Ballot process shall:
  i. Use all votes cast by ballot pool member to establish quorum.
  ii. Provide options for voting “No” with guiding choices for the answer with a comment section on the ballot.
- Formalize the use of formal, rigorous project management (i.e., trained leaders, facilitators, scribes, etc.) within SDTs to ensure greater efficiency and effectiveness of the SDTs.
- Revise formation and composition of SDTs model.
  i. Incorporate the support of technical writers, legal, compliance and rigorous and highly trained facilitation support.

ii. Ensure adequate representation and competencies based on complexity of the issue.

- Promote efficiency and timeliness by setting milestones and progress reports.

Additional Issues to be Addressed (per the Board's Discretion) During the Implementation Phase

- Reinforce mechanisms to add during the commenting process.

i. Locked list of answer options (e.g., "risk to reliability," "cost concerns," etc.).

ii. "Other" option for the No vote list with a comment section that requires explanation that this approach will balance input to empower the SC to conduct a more thorough balloting process.

iii. Consider bolding of text instructions on all ballots that emphasize the importance of clarity.

iv. Consider the advantage/disadvantage to establishing voting record for each participant/entity.

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Standards Announcement

Project 2012-INT-02 - Interpretation of TPL-003 and TPL-004 for System Protection and Control Subcommittee

Formal Comment Period Open: June 20 – July 19, 2012

Now Available

A formal comment period for the interpretation of **TPL-003-0a** – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) and **TPL-004-0** – System Performance Following Extreme Events Results in the Loss of Two or More Bulk Electric System Elements (Category D) is open through 8 p.m. Eastern on Thursday, July 19, 2012.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Thursday, July 19, 2012.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will consider all comments and determine whether to make changes to the interpretation response. If significant changes are made to the interpretation response the drafting team will submit the interpretation response for quality review prior to the next posting.

Background

Order No. 754, issued September 15, 2011, was the Final Rule approving the Interpretation of TPL-002-0a for PacifiCorp (Project 2009-14) regarding requirement R1.3.10. In addition to the approval, the Commission expressed a concern (Para 19 and 20) about single point of failure of protection systems and issued NERC a directive for further investigation. This request for interpretation submitted by the System Protection and Control Subcommittee (SPCS) is one of three approaches aimed to address the concern. The SPCS is seeking clarification in two areas in TPL-003-0a (Category C) and TPL-004-0 (Category D). The first regarding the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "(stuck breaker or protection system failure)." Second, to what extent does the description in the standards' Table 1, footnote (e) require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system.

Additional information is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Interpretation Request Form
2012-INT-02 TPL-003-0a and TPL-004-0

When completed, email this form to:
laura.hussey@nerc.net
For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

Note: A valid interpretation request is one that requests additional clarity about one or more requirements in approved NERC reliability standards, but does not request approval as to how to comply with one or more requirements.

Request for an Interpretation of a Reliability Standard			
Date submitted:	December 12, 2011		
Contact information for person requesting the interpretation.			
Name:	Jonathan Sykes (PG&E), Chairman SPCS		
Organization:	NERC System Protection & Control Subcommittee		
Telephone:	(510) 874-2691	**E-mail:**	jfst@pge.com

Identify the Standard (include version number, e.g., PRC-001-1) that needs clarification and its associated title.	
Standard	**Title**
TPL-003-0a	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
TPL-004-0	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Identify specifically what Requirement needs clarification.	
Standard	**Requirement (and text)**
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that

	would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Identify the nature of clarification that is requested (Check as many as applicable).

- ☒ Clarify the required performance
- ☐ Clarify the conditions under which the performance is required
- ☐ Clarify which functional entity is responsible for performing an action in a requirement
- ☐ Clarify the reliability outcome the requirement is intended to produce

Please explain the clarification needed.

This interpretation request has been developed to address Commission concerns related to the term "Single Point of Failure" and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the

evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to

[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)

[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."

[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.

Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect interpretation of this standard.

There is a material impact to the entities required to perform transmission planning assessments and to the entities that may rely on these assessments. The lack of clarity in defining the required studies impacts entities by:

- Potential non-compliance if the correct contingencies are not studied
- Inefficient use of resources if contingencies are studied that are not required and mitigation plans are implemented that are not required
- Potential negative impact to grid reliability if the correct contingencies are not assessed

[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Response for Interpretation of TPL-003 and TPL-004 for SPCS

Note: A valid interpretation request is one that requests additional clarity about one or more requirements in approved NERC reliability standards, but does not request approval as to how to comply with one or more requirements.

Request for an Interpretation of a Reliability Standard			
Date submitted:	December 12, 2011		
Contact information for person requesting the interpretation.			
Name:	Jonathan Sykes (PG&E), Chairman SPCS		
Organization:	NERC System Protection & Control Subcommittee		
Telephone:	(510) 874-2691	**E-mail:**	jfst@pge.com

Identify the Standard (include version number, e.g., PRC-001-1) that needs clarification and its associated title.	
Standard	Title
TPL-003-0a	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
TPL-004-0	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Identify specifically what Requirement needs clarification.	
Standard	Requirement (and text)
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including

	any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Identify the nature of clarification that is requested (Check as many as applicable).

- ☒ Clarify the required performance
- ☐ Clarify the conditions under which the performance is required
- ☐ Clarify which functional entity is responsible for performing an action in a requirement
- ☐ Clarify the reliability outcome the requirement is intended to produce

Please explain the clarification needed.

This interpretation request has been developed to address Commission concerns related to the term "Single Point of Failure" and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the

operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to model a single point of failure of a protection system component that may prevent correct operation of

[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)

[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."

[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.

Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect interpretation of this standard.

There is a material impact to the entities required to perform transmission planning assessments and to the entities that may rely on these assessments. The lack of clarity in defining the required studies impacts entities by:

- Potential non-compliance if the correct contingencies are not studied
- Inefficient use of resources if contingencies are studied that are not required and mitigation plans are implemented that are not required
- Potential negative impact to grid reliability if the correct contingencies are not assessed

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

Standard	Requirement (and text)
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.

Question 1

For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[9] of either "stuck breaker" or "protection system failure" contingency[10], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

Response 1

[9] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

[10] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. Evaluation of a SLG (TPL-003-0a, Category C) and Three-phase (TPL-004-0, Category D) Fault with delayed clearing is required and further defined by footnote (e) and the parenthetical phrase "stuck breaker or protection system failure." Footnote (e) explains that "Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay." The parenthetical further emphasizes that the failure may be a "stuck breaker or protection system failure" that causes the delayed clearing of the fault. The ordered reading of the text in Table 1 explains that delayed clearing caused by a failure of a protection system or circuit breaker must be evaluated to examine its impact on BES performance. Therefore, the transmission planner must consider the situation that produces the more severe system results or impacts due to a delayed clearing condition regardless whether the condition resulted from either a stuck breaker or protection system failure.

Standard	Requirement (and text)
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Question 2

For the phrase "Delayed Clearing[11]" used in Category C[12] contingencies 6-9 and Category D[13] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[14] require an entity to model a single point of failure of a protection system component that may prevent correct operation of

[11] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[12] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

[13] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

[14] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?
Response 2
The term “Delayed Clearing” that is described in Table 1, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. Any failure of a protection system component that increases clearing times of one or more protection systems requires the Transmission Planner and Planning Authority to simulate the full impact on the Bulk Electric System performance.

Revision History (To be removed upon Final)

Version	Date	Description
1.0	5/9/2012	Draft 1 of the response to the request for interpretation.

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 23, 2010

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-0

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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Standards Announcement

Project 2010-INT-01 Rapid Revision of TOP-006 for FMPP

Ballot Pool Forming:	June 14 – July 13, 2012
Formal Comment Period Open:	June 14 – July 30, 2012

Upcoming:

Initial Ballot and Non-Binding Poll:	July 20 – July 30, 2012

Now Available

A formal comment period for the rapid revision of **TOP-006-3** – Monitoring System Conditions is open through 8 p.m. Eastern on Monday, July 30, 2012 and ballot pools are being formed through 8 a.m. Friday, July 13, 2012.

Two different types of changes are being made to TOP-006-3. Those changes have been highlighted in the redline version in either yellow or green. The redline changes highlighted in yellow are in response to the rapid revision of TOP-006-2. The redline updates highlighted in green are updates that are being made to bring the standard up to the current boiler plate wording approved by the Standards Committee and to incorporate the VRF/VSLs that have been approved by the NERC Board.

Instructions for Joining Ballot Pool

Two ballot pools are being formed. Registered Ballot Body members must join the first ballot pool to be eligible to vote in the balloting of standard TOP-006-3, and a second, separate ballot pool to be eligible to cast an opinion in the non-binding poll for the VRF and VSL for Requirements R1.3. Registered Ballot Body members may join each of the ballot pools at the following page: Join Ballot Pool.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list servers for this ballot pool are:

Initial ballot: bp-2010-INT-01:TOP-006_in@nerc.com
Non-binding poll: bp-2010-INT-01_NB_in@nerc.com

The ballot pools are open **through 8 a.m. Eastern on Friday, July 13, 2012**.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, July 30, 2012.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Commenters and voters must submit comments through the electronic comment form. Due to modifications to NERC's balloting software, voters are no longer able to submit comments via the balloting software.

Next Steps

An initial ballot of the standard and non-binding poll of the VRF and VSL for Requirement R1.3 will be conducted beginning Friday, July 20, 2012 through 8 p.m. Eastern on Monday, July 30, 2012.

Background

Florida Municipal Power Pool (FMPP) submitted a request for interpretation of TOP-006-2 asking for clarification for Requirements R1.2 and Requirement R3. For Requirement R1.2, since the Balancing Authority is not responsible for transmission, FMPP asked if the Balancing Authority is responsible for reporting generation resources available for use and the Transmission Operator responsible for reporting transmission resources that are available for use. For Requirement R3, FMPP asked if the "appropriate technical information concerning protective relays" only refers to protective relays for which the entity has responsibility.

At the January 2012 meeting, the Standards Committee approved the interpretation be converted to a rapid revision.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
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Project 2010-INT-01 - TOP-006-2 for FMPP
Implementation Plan

Requested Approvals

- TOP-006-3 – Monitoring System Conditions

Requested Retirements

- TOP-006-2 – Monitoring System Conditions

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Standards Committee approved a rapid development process for changes to TOP-006-2 in order to respond to an interpretation request involving Requirements R1.2 and R3. The project was assigned to the Standards Drafting Team for Project 2007-03 Real-time Operations.

General Considerations

Requirement R1.2 was revised to show that Transmission Operators will be responsible for transmission information. Requirement R1.3 was created to clarify that the Balancing Authorities provide generation information to its Reliability Coordinator and Transmission Operator but not to other Balancing Authorities. (This eliminates the need for CAN-0028.) These changes are consistent with the roles and responsibilities for these entities in Functional Model v5. The Measures, Data Retention, and VSLs have been adjusted accordingly.
Requirement R3 was clarified to show that entities will only be responsible for providing relay information for equipment that they are responsible for. (This eliminates the need for CAN-0026.)
Time Horizons have been added for all requirements.
Formatting has been brought up to the latest guidelines.

Applicable Entities

- Transmission Operators
- Balancing Authorities
- Generator Operators
- Reliability Coordinators

Effective Dates

In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Already Approved Standard	Proposed Replacement Requirement(s)
TOP-006-2 **R1.2** Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.	TOP-006-3 R1.2 Each Transmission Operator shall inform the Reliability Coordinator and other affected Transmission Operators of all transmission resources available for use. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*] R1.3 Each Balancing Authority shall inform its Reliability Coordinator and its Transmission Operators of all generation resources available for use. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
Notes: The RTOSDT recommends replacing R1.2 with a revised R1.2 and a new R1.3 as shown. This will allow for the proper allocation of responsibility for the information cited as per Functional Model v5.	

Already Approved Standard	Proposed Replacement Requirement(s)
TOP-006-2 **R3** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	TOP-006-3 **R3** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide its operating personnel with appropriate technical information concerning protective relays for which the entity has responsibility. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
Notes: The RTOSDT recommends the insertion of the phrase 'for which the entity has responsibility' which will make it clear that an entity can only supply information for equipment that they have responsibility for and not for equipment that is another entity's responsibility.	

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Standards Authorization Request Form

When completed, email this form to:
Andy.Rodriquez@nerc.net
For questions about this form or for assistance in completing the form, call Andy Rodriquez at 404-446-2579.

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	TOP-006-3 – Monitoring System Conditions		
Date Submitted:	February 3, 2012		
SAR Requester Information			
Name:	James Case, Chair of Project 2007-03 Real-time Operations		
Organization:	Entergy		
Telephone:	(601) 985-2345	E-mail:	jcase@entergy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
X Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
There is a need for additional clarity surrounding Requirements R1.2 and R3 in TOP-006-2 as pointed out in an interpretation request from the Florida Municipal Power Pool.
Purpose or Goal (How does this request propose to address the problem described above?):
This SAR proposes to modify TOP-006-2, Requirements R1.2 and R3 to provide the needed clarity in the subject requirements.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Address the need for additional clarity in the subject requirements as per the interpretation request.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Changes will be made to Requirements R1.2 and R3 to bring needed clarity to the standard.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Requirement R1.2 will be revised to apply solely to the Transmission Operator (as per the Functional Model v5) for dealing with transmission information. Requirement R1.3 will be created to apply solely to the Balancing Authority (as per the Functional Model v5) for delaing with generation information. Requirement R3 will be revised to state that information can only be provided by a functional entity that it has responsibility for. The SDT will also make conforming changes to the standard to add missing Time Horizons and to bring the compliance elements into conformance with the latest standard template.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and

Reliability Functions		
		supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner

Reliability and Market Interface Principles	
	to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Y
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Y
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Y
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Y

Related Standards	
Standard No.	Explanation
	N/A

Related Standards	

Related SARs	
SAR ID	Explanation
	N/A

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

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Violation Risk Factor and Violation Severity Level Assignments

Project 2010-INT-01 TOP-006-2 for FMPP

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for new Requirement R1.3 in TOP-006-3 – Monitoring System Conditions. None of the other existing, approved values are being changed.

The new requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in TOP-006-3, Requirement R1.3:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-006-3, Requirement R1.3:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eleven requirements in TOP-001-2. None of the eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, R4, R7, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-006-3, Requirement R1.3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The sub-requirements all require similar performance and all have the same VRF of Medium. Therefore, there is consistency.
- FERC's Guideline 3 — Consistency among Reliability Standards. This new requirement is exactly analogous to the approved Requirement R1.2 that is assigned a Medium VRF. The only difference is that Requirement R1.2 applies to a Transmission Operator while the new Requirement R1.3 applies to the Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to supply the cited information will not, by itself, lead to instability, separation, or cascading failures. Failure to provide this information could, however, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Thus, a Medium VRF is justified.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-006-3, Requirement R1.3 contains only one objective, therefore only one VRF was assigned.

Justification for Assignment of Violation Severity Levels for TOP-006-3, Requirement R1.3:
In developing the VSLs for Requirement R1.3 in TOP-006-3, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for Requirement R1.3 in TOP-006-3 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties
A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement
VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for TOP-006-3, Requirement R1.3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is exactly analogous to approved TOP-006-2, Requirement R1.2. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Standards Committee approved rapid development process on January 11, 2012.

Proposed Action Plan and Description of Current Draft:
The Standards Committee approved a rapid revision process for changes to TOP-006-2 in order to respond to an interpretation request involving Requirements R1.2 and R3. The project was assigned to the Standards Drafting Team for Project 2007-03 Real-time Operations.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for comment and initial ballot.	2Q12
2. Post for recirculation ballot.	3Q12
3. Submit to BOT.	4Q12

Please note the yellow and green highlighted material.

The redline changes highlighted in yellow are changes being made in response to the rapid revision. The SDT is soliciting your feedback on this material.

The redline updates highlighted in green are updates that are being made to bring the standard up to the current boiler plate wording approved by the Standards Committee and to incorporate the VRF/VSLs that have been approved by the NERC Board. The SDT is not soliciting feedback on this material.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Monitoring System Conditions**
2. **Number:** TOP-006-~~2~~3
3. **Purpose:** To ensure critical reliability parameters are monitored in real-time.
4. **Applicability:**
   - **4.1. Functional Entities**
     - **4.1.1** Transmission Operators
     - **4.1.2** Balancing Authorities
     - **4.1.3** Generator Operators
     - **4.1.4** Reliability Coordinators
5. **(Proposed) Effective Date:** All requirements become effective the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R1.2. Each Transmission Operator ~~and Balancing Authority~~ shall inform the Reliability Coordinator and other affected ~~Balancing Authorities and~~ Transmission Operators of all ~~generation and~~ transmission resources available for use. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

> Transmission Operators deal with transmission information while Balancing Authorities deal with generation information as detailed in Functional Model v5.

R1.3. Each Balancing Authority shall inform its Reliability Coordinator and its Transmission Operator(s) of all generation resources available for use. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide its operating personnel with appropriate technical information concerning protective relays for which the entity has responsibility~~to their operating personnel~~. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

> Entities can only provide information related to items for which they have responsibility.

R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Same-day Operation, Real-time Operations*]

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)

M2. Each Transmission Operator ~~and Balancing Authority~~ shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected ~~Balancing Authorities and~~ Transmission Operators of all ~~generation and~~ transmission resources available for use. (Requirement 1.2)

~~**M2.**~~**M3.** Each Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and its Transmission Operators of all generation resources available for use. (Requirement 1.3)

M4. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.

~~**M3.**~~**M5.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, operating instructions, training materials, or other equivalent evidence that will be used to confirm that it informed its operating personnel of appropriate technical information concerning protective relays for which they have responsibility. (Requirement 3)

~~**M4.**~~**M6.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system's near-term load pattern. (Requirement 4)

~~**M5.**~~**M7.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)

~~**M6.**~~**M8.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift-operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~ Enforcement Authority

~~Regional Reliability Organizations shall be responsible for compliance monitoring.~~ The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

~~**Compliance Monitoring and Reset Time Frame**~~

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30~~

~~days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

1.2. Data Retention

Each Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.

Each Transmission Operator ~~and Balancing Authority~~ shall keep 90 days of historical data (evidence) for Measure 2.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measure 3.

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure ~~3~~4, 5. ~~5~~7 and ~~6~~8.

Each Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure ~~4~~6.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data.

1.3. Compliance Monitoring and Assessment Processes

One or more of the following methods will be used to assess compliance:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	N/A	N/A	N/A	The responsible entity failed to know the status of all generation and transmission resources available for use, even though said information was reported by the Generator Operator, Transmission Operator, or Balancing Authority.
R1.1	Real-time Operations	Medium	N/A	N/A	N/A	The Generator Operator failed to inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
R1.2	Real-time Operations	Medium	N/A	N/A	N/A	The responsible entity failed to inform the Reliability Coordinator and other affected ~~Balancing Authorities and~~ Transmission Operators of all ~~generation and~~ transmission resources available for use.
R1.3	Real-time	Medium	N/A	N/A	N/A	The responsible entity failed to inform its

	Operations					Reliability Coordinator and its Transmission Operators of all generation resources available for use.
R2	Real-time Operations	High	N/A	The responsible entity monitors the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, but is not aware of the status of rotating and static reactive resources.	The responsible entity fails to monitor all of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of all rotating and static reactive resources.	The responsible entity fails to monitor any of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
R3	Operations Planning	Medium	The responsible entity failed to provide any of the appropriate technical information concerning protective relays for which it has responsibility to their operating personnel.	N/A	N/A	The responsible entity failed to provide all of the appropriate technical information concerning protective relays for which it has responsibility to their operating personnel.
R4	Operations Planning, Same-day Operations, Real-time Operations	Medium	N/A	N/A	The responsible entity has either weather forecasts or past load patterns, available to predict the system's near-term load pattern, but not both.	The responsible entity failed to have both weather forecasts and past load patterns, available to predict the system's near-term load pattern.
R5	Real-time Operations	Medium	N/A	N/A	The responsible entity used monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions, but does not	The responsible entity failed to use monitoring equipment to bring to the attention of operating personnel important deviations in operating

					have indication of the need for corrective action.	conditions.
R6	Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
R7	Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to monitor system frequency.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Modified R4 Modified M4 Modified Data Retention for M4 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	
2	March 23, 2011	Order issued by FERC approving TOP-006-2 (approval effective 5/23/11)	
3	TBD	Rapid revision to accommodate interpretation request for Requirements R1.2 & R3	Changes to bring document format to new guidelines. Changes to Requirements R1.2 & R3. Added Time Horizons.

Implementation Plan
2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions

Requested Approvals
It is requested that the following definitions be approved for addition to the NERC Glossary of Terms used in Reliability Standards:

- "Bulk Power System" means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

- "Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.

- "Reliable Operation" means operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.

Requested Retirements
No Reliability Standards or definitions are requested to be retired with the approval of the addition of the definitions for Bulk Power System, Reliability Standard, and Reliable Operation to the NERC Glossary of Terms used in Reliability Standards.

Prerequisite Approvals
No Reliability Standard or definition is under development that must be completed or implemented before the definitions for Bulk Power System, Reliability Standard, and Reliable Operation can be added to the NERC Glossary of Terms used in Reliability Standards.

Background

In Paragraph 1894 of the Federal Energy Regulatory Commission (FERC) Order 693, the Commission directed the Electric Reliability Organization to include the statutory definitions of Bulk Power System, Reliability Standard, and Reliable Operation in the NERC Glossary of Terms used in Reliability Standards:

"1894. The Commission directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard. However, this determination does not negate our discussion in the Applicability section of the Final Rule. While the glossary should be revised to include the statutory definition of Bulk-Power System, the Reliability Standards refer to the bulk electric system, which is also defined in the glossary."

The statutory definitions for Bulk Power System, Reliability Standard, and Reliable Operation are contained in the Electricity Modernization Act of 2005. Inclusion of the statutory definitions for Bulk Power System, Reliability Standard, and Reliable Operation in the NERC Glossary of Terms used in Reliability Standards will address three outstanding Commission directives.

The statutory definitions for Bulk Power System, Reliability Standard, and Reliable Operation contained in the Electricity Modernization Act of 2005 were previously submitted by NERC in a petition to FERC, dated November 29, 2011. The petition requested approval of numerous revisions to NERC's Rules of Procedure (ROP); including, but not limited to, a new Appendix 2 to the ROP, *Definitions Used in the Rules of Procedure*. On January 31, 2012, the Commission issued an Order approving NERC's November 29, 2011, request.

The proposed definitions for Bulk Power System, Reliability Standard, and Reliable Operation are identical to the definitions approved by the Commission in their January 31, 2012 Order and are responsive to the Commission's directives from Paragraph 1894 of Order 693. Approval of the proposed definitions for Bulk Power System, Reliability Standard, and Reliable Operation also ensures both the NERC Glossary of Terms used in Reliability Standards and the NERC ROP contain consistent (identical) definitions for these terms.

Effective Date

The definitions of Bulk Power System, Reliability Standard, and Reliable Operation shall be added to the NERC Glossary of Terms used in Reliability Standards effective upon applicable regulatory approval.

From: NERC Standards Announcements (Do Not Reply)
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Minor Document Edit Noted: Project 2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions
Date: Wednesday, July 11, 2012 11:27:29 AM

Standards Announcement

Project 2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions

Please note:

A typographical error has been identified in the posted document for this project. A minor edit (in red text) was made to the following definition:

- **"Bulk Power System"** means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and (ii) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

The revised document has been posted on the project page.

Project Date Reminders:

Ballot Pools Forming: June 19 – July 18, 2012

Formal Comment Period Open: June 19 – August 2, 2012

Initial Ballot: July 24 – August 2, 2012

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Suite 600, North Tower
Atlanta, GA 30326
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You have received this email because you are a registered representative in the Registered Ballot Body.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee (SC) authorized NERC posting a Standard Authorization Request (SAR) for adding the statutory definitions of Bulk Power System, Reliability Standard, and Reliable Operation to the NERC Glossary of Terms used in Reliability Standards for a 45-day formal comment period, with an initial ballot during the final 10 days of that comment period. Standards Committee authorization occurred during the May 10, 2012 SC meeting.

Description of Current Draft

This is the initial posting and ballot for adding the statutory definitions (without modification) of Bulk Power System, Reliability Standard, and Reliable Operation to the NERC Glossary of Terms used in Reliability Standards for a 45-day formal comment period, with an initial ballot during the final 10 days of that comment period.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	June 2012
Recirculation ballot	September 2012
BOT adoption	November 2012

Effective Dates

The definitions of Bulk Power System, Reliability Standard, and Reliable Operation shall be added to the NERC Glossary of Terms used in Reliability Standards effective upon applicable regulatory approval.

Version History

Version	Date	Action	Change Tracking

1	TBD	Addition of the definitions of Bulk Power System, Reliability Standard, and Reliable Operation to the NERC Glossary of Terms used in Reliability Standards.	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

NOTE: The highlighted '(ii)' was inadvertently omitted in the original posted document, but is part of the statutory definition of Bulk Power System included in the Energy Policy Act of 2005.

"Bulk Power System" means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and (ii) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

"Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.

"Reliable Operation" means operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee (SC) authorized NERC posting a Standard Authorization Request (SAR) for adding the statutory definitions of Bulk Power System, Reliability Standard, and Reliable Operation to the NERC Glossary of Terms used in Reliability Standards for a 45-day formal comment period, with an initial ballot during the final 10 days of that comment period. Standards Committee authorization occurred during the May 10, 2012 SC meeting.

Description of Current Draft

This is the initial posting and ballot for adding the statutory definitions (without modification) of Bulk Power System, Reliability Standard, and Reliable Operation to the NERC Glossary of Terms used in Reliability Standards for a 45-day formal comment period, with an initial ballot during the final 10 days of that comment period.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	June 2012
Recirculation ballot	September 2012
BOT adoption	November 2012

Effective Dates

The definitions of Bulk Power System, Reliability Standard, and Reliable Operation shall be added to the NERC Glossary of Terms used in Reliability Standards effective upon applicable regulatory approval.

Version History

Version	Date	Action	Change Tracking

1	TBD	Addition of the definitions of Bulk Power System, Reliability Standard, and Reliable Operation to the NERC Glossary of Terms used in Reliability Standards.	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

"Bulk Power System" means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

"Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.

"Reliable Operation" means operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

E-mail completed form to
sarcomm@nerc.com

Standard Authorization Request Form

Request Date	March 15, 2012

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Individual, Group, or Committee Name David Taylor	☐	New Standard
Primary Contact (if Group or Committee)	☐	Revision to existing Standard
Company or Group Name NERC	☐	Withdrawal of existing Standard
E-mail David.Taylor@nerc.net	☐	Project Identified in Reliability Standards Development Plan (Project Number and Name:)
Telephone (609) 651-5089	☒	Modification to NERC Glossary term or addition of new term

116-390 Village Boulevard
Princeton, New Jersey 08540-5721
609.452.8060 | www.nerc.com

Brief Description of Proposed Standard Modifications / Actions

The Federal Energy Regulatory Commission (FERC) issued directives in FERC Order 693 requiring the addition of the statutory definitions for Bulk Power System, Reliable Operation, and Reliability Standard to the Glossary of Terms used in Reliability Standards. The purpose of this SAR is to add the definitions to the glossary.

Need

By adding the definitions for Bulk Power System, Reliable Operation, and Reliability Standard to the Glossary of Terms used in Reliability Standards, NERC will be complying with mandatory directives in Order 693 issued by FERC.

Goals

The definitions for Bulk Power System, Reliable Operation, and Reliability Standard will be added to the Glossary of Terms used in Reliability Standards.

Objectives and / or Potential Future Metrics

The criteria for success will be regulatory approval of the statutory definitions for Bulk Power System, Reliable Operation, and Reliability Standard being added to the Glossary of Terms used in Reliability Standards.

Detailed Description

In Paragraph 1894 of Order 693, the Commission directed the Electric Reliability Organization to include the statutory definitions of Bulk Power System, Reliability Standard, and Reliable Operation in the NERC Glossary of Terms used in Reliability Standards:

> "1894. The Commission directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard. However, this determination does not negate our discussion in the Applicability section of the Final Rule. While the glossary should be revised to include the stautory definition of Bulk-Power System, the Reliability Standards refer to the bulk electric system, which is also defined in the glossary."

Inclusion of the proposed terms for Bulk Power System, Reliability Standard, and Reliable Operation in the NERC Glossary of Terms used in Reliability Standards will address three outstanding Commission directives.

On November 29, 2011, NERC submitted a petition to the Commission requesting approval of revisions to NERC's Rules of Procedure (ROP), including revisions to Sections 100 through 1600 of the ROP and Appendices 3A, 3B, 3C, 3D, 4A, 4B, 4C, 4D, 4E, 5A, 5B, 6 and 8, and a new Appendix 2, *Definitions Used in the Rules of Procedure*. The purposes of the proposed revisions were (1) to place all definitions of defined terms used anywhere in the ROP in a single, readily-accessible location (proposed new Appendix 2); (2) to capitalize defined terms throughout the ROP where such terms are intended to be used in their defined meanings; and (3) to lower-case other terms that are currently capitalized in the ROP but are not defined terms.

On January 31, 2012, the Commission issued an Order approving NERC's November 29, 2011 request.

The proposed definitions for Bulk Power System, Reliability Standard, and Reliable Operation below, even though not identical to the statutory terms included in Section 215(a) of the Federal Power Act, are identical to the definitions approved by the Commission in their January 31, 2012 Order; and, therefore, are an equally efficient and effective response to the Commission's directives from Order 693.

The following definitions should be added to the NERC Glossary of Terms Used in Reliability Standards in order to comply with the FERC directives in Paragraph 1894 of Order 693:

- **"Bulk Power System"** means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.
- **"Reliability Standard"** means a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.
- **"Reliable Operation"** means operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.

As the definitions for Bulk Power System, Reliable Operation, and Reliability Standard proposed here are identical to the definitions approved by the Commission in their January 31, 2012 Order, no changes should be made to the definitions. It is recommended that the Standards Committee waive the requirement for posting for industry comment and that the definitions go straight to industry ballot.

OPTIONAL: Technical Analysis Performed to Support Justification N/A

Reliability Functions

The Standard(s) May Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Regional Entity	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☒	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☒	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☒	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☒	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard(s) comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related Projects

Project ID and Title	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

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Standards Announcement

Project 2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions

Ballot Pools Forming:	June 19 – July 18, 2012
Formal Comment Period Open:	June 19 – August 2, 2012

Upcoming Ballots
Initial Ballot: July 24 – August 2, 2012

Now Available

A formal comment period for **Phase 1 of the Glossary Updates for Statutory Definitions** is open through 8 p.m. Eastern on Thursday, August 2, 2012 and a ballot pool is forming through 8 a.m. Wednesday, July 18, 2012.

Instructions for Joining Ballot Pool(s)

A ballot pool is being formed. Registered Ballot Body members must join the ballot pool to be eligible to vote in balloting of Phase 1 of the Glossary Updates for Statutory Definitions. Registered Ballot Body members may join the ballot pool at the following page: Join ballot pool

During the pre-ballot window, members of the ballot pools may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The ballot pool list server for this ballot pool is: bp-2012-08.1_Phase_1_in@nerc.com

The ballot pool is open **through 8 a.m. Eastern on Wednesday, July 18, 2012.**

Instructions for Commenting

A formal comment period is open through 8 p.m. Eastern on Thursday, August 2, 2012. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Commenters and voters must submit comments through the electronic comment form (link shown above). Due to modifications to NERC's balloting software, voters are asked to submit their ballot comments via the electronic comment form.

Next Steps

An initial ballot of Phase 1 of the Glossary Updates for Statutory Definitions will be conducted beginning on Tuesday, July 24, 2012 through 8 p.m. Eastern on Thursday, August 2, 2012.

Background

In paragraph 1894 of Federal Energy Regulatory Commission (FERC) Order 693 the Commission directed the Electric Reliability Organization to include the statutory definitions of Bulk Power System, Reliability Standard, and Reliable Operation in the NERC Glossary of Terms Used in Reliability Standards:

"1894. The Commission directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard. However, this determination does not negate our discussion in the Applicability section of the Final Rule. While the glossary should be revised to include the statutory definition of Bulk-Power System, the Reliability Standards refer to the bulk electric system, which is also defined in the glossary."

The statutory definitions for Bulk Power System, Reliability Standard, and Reliable Operation are contained in the Electricity Modernization Act of 2005. Inclusion of the statutory definitions for Bulk Power System, Reliability Standard, and Reliable Operation in the NERC Glossary of Terms Used in Reliability Standards will address three outstanding Commission directives.

Additional information can be found on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Reliability Guideline: System Operator Verbal Communications – Current Industry Practices

Preamble:

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). Reliability Guidelines provide suggested guidance on a particular topic for use by BES users, owners, and operators according to each entity's circumstances. Reliability Guidelines are not to be used to provide binding norms, establish mandatory reliability standards, or create parameters by which compliance to standards is monitored or enforced.

Introduction:

This Reliability Guideline is applicable to electricity sector organizations responsible for the operation of the BES. It provides general concepts that may be considered when developing a system operator verbal communications program. This guideline provides a general framework for identifying the concepts and steps to consider for an effective system operator verbal communications program. This document, written in the form of a guideline, is a collection of industry practices compiled by the NERC Operating Committee (OC). The use of these methodologies and guidelines are strictly voluntary**.**

Purpose:

The purpose of this guideline is to document and share current verbal BES communications practices and procedures from across the industry that have been found to enhance the effectiveness of system operator communications programs. These are not mapped to existing or future mandatory requirements, but rather are intended to show the breadth of industry practices concerning verbal communications.

Guideline Details:

Components of an effective system operator verbal communications program may include:

I. Verbal Communications Tools

System operators use a variety of tools for communicating information with other system operators. The tool used for communicating specific information with various recipients depends on a number of factors, such as the urgency, importance, and intended impact of the information being communicated. The urgency, importance, and impact of the specific information are highly dependent on the role and responsibility of each party to the communication. As an example, email may be the appropriate tool if the information exchange is not urgent, while a one-on-one phone call may be the best method to communicate both urgent and important information. Also, in some cases multiple tools may be used to communicate the same information to different parties.

Tools used for system operator communications and some typical applications for those tools are as follows:

A. Voice Communications

1) Public Switched Telephone Network (PSTN) – This is the most common communication tool for system operators to communicate with other system operators and field personnel. It is highly reliable and secure. Application examples include:

   a. Dedicated conference call arrangements

   b. Dedicated circuits between facilities

   c. Multi-party initiated calls

   d. Speed dial functionality

2) Private Internal Telecommunications Systems – Some utilities have found economies of scale by installing their own communications network utilizing microwave and/or fiber optic telecommunications networks. These networks perform the same function as the PSTN discussed above.

3) Voice Over Internet Protocol (VOIP) – The communication protocols, technologies, methodologies, and transmission techniques involved in the delivery of voice communications and multimedia sessions over Internet Protocol (IP) networks, such as the Internet, rather than the public switched telephone network (PSTN).

4) Cell phones – These are widely used by field personnel to contact system operators. They are reliable in urban and suburban settings but less reliable in remote areas. Cell phones function similarly to traditional phones but are more susceptible to background noise.

5) Radios – A common communication medium for municipal utilities and vertically integrated utilities where uses extend beyond operation of the BES. The communication method for radios differs from other devices because they are not full duplex devices and, therefore, do not allow simultaneous transmission from both parties. Also, radio transmissions are typically not encrypted and are accessible to third parties via scanners, etc.

6) Government Emergency Telecommunications Service (GETS) and Wireless Priority Service (WPS) – GETS and WPS provide an emergency access and priority processing in the local and long-distance segments of the PSTN or cellular networks. GETS and WPS are intended to be used in an emergency or crisis situation when the PSTN or cellular network is congested and the probability of completing a call over normal or other telecommunications means has significantly decreased.

7) Satellite phones – Typically used as emergency voice communication medium between functional entities and their respective reliability coordinator. Satellite phones function similarly to traditional phones and cell phones; however, a clear view of the sky for the antenna is required. A lesson learned from the industry's Y2K preparation was that for

satellite phones to be most effective in emergency/outage conditions, entities have to ensure their phones do not require transmitting through any ground relaying stations (i.e., that their phones have direct point-to-point functionality).

8) All Call/Blast Call Functionality – Some entities utilize technology that blasts general messaging and directives to multiple entities.

B. Other Communications Tools

1) Email – Typically used to communicate information that is not time sensitive and has redundant sources. Used to communicate system status and events to a broad array of support staff/management as well as interconnected entities.

2) Messaging Systems – An internal system used by reliability coordinators to send messages to their balancing authorities and transmission operators or an external system used by reliability coordinators to send messages to other reliability coordinators (e.g., the Reliability Coordinator Information System).

3) Fax (short for facsimile) – Sometimes called telecopying, faxing is the telephonic transmission of scanned printed material (both text and images), normally to a telephone number connected to a printer or other output device.

II. Policies and Procedures

The following are excerpts of policies and procedures currently in use by a sampling of industry members. When developing formal communications policies and procedures, the registered entity may consider addressing the following items:

A. Policy Applicability

1) Who – To whom the procedure applies

2) When – Under what condition the specific communications policy or procedure is to be used (e.g., normal or emergency conditions)

3) How – Technique to be used for emergency communications versus normal communications

a. There are two schools of thought regarding utilization of three-part communication for routine operating instructions. Every routine communication opportunity has a differing impact on the reliability of the BES, and many routine communication opportunities have no impact on reliability. While the industry has disparate viewpoints on the necessity of the use of three-part communication for all real-time communications, most agree that the point is to be effective when it counts for reliability, not that every communication opportunity has a reliability impact. Use of three-part communication for routine operations is intended to be "practice" for those events when reliability is directly impacted by a communication opportunity.

1. One thought is that the three-part communication protocol is special and reserved to address real-time emergencies in order to make those communications stand out from normal communications.
2. Another school of thought is that the three-part communication protocol is good practice for both normal and emergency operating instructions.

b. If an entity determines it would utilize the three-part communication protocol for routine operating instructions, it is that entity's responsibility to define when its system operators are expected to utilize the protocol, including coordinating with entities regarding when the use of three-part communication is expected.

B. Use of Three-Part Communication for Routine Operating Instructions[1] – The following is an example of when the three-part communication protocol for routine operating instructions could be implemented:

> SAMPLE TEXT from an internal procedure:
>
> 1) For any actionable item, there should be specific three-part communication by the receiver to ensure there is no misunderstanding of the details involved. An actionable item is instruction or information conveyed in which one party is informing the other that:
>
> a. A physical change needs to be made or has been made to BES facilities pre- or post-contingency (e.g., generation starts, transmission reconfigurations, manual redispatches, load shedding, voltage changes); or
>
> b. A change needs to be made in the computer systems used to operate the BES (e.g., updating operating limits, forecasts, schedules).

C. Directives in an Emergency – It is recommended that it be made clear when issuing a directive in an emergency that three-part communication is required.

1) Entities might consider providing system operators a general format or a script that can be used when issuing directives in an emergency. Some entities provide these written scripts at each system operator position and may ask the receiver to write out the transmitted directive.

[1] While the practice of using three-part communications for routine communications may be a good practice, the failure to use three-part communications for routine communications is not considered to undermine reliability.

D. Elements of Effective Communication

1) Communication Etiquette – At all times, professionalism and professional tone and manner are essential. Communications are best undertaken in a courteous, business-like fashion.

2) Opening Phrase – It is important that both parties understand with whom they are speaking; therefore, the person answering the phone or making a call should state the following information: company, name, and function.

3) Acknowledgement – Whenever a call is made or received, the initiating party should clearly communicate the purpose of the call so that all issues are fully understood and addressed.

4) Content – The person requesting action should speak in a clear and calm manner, review the information and request repeat back, if appropriate. If any action is to be taken, the recipient will fully understand when that action is expected to be taken (e.g., now, at a specific time, or "some" time).

5) Closing – At the end of any call, those communicating want to confirm that what was expected was completed, that no other activity is required, and whether there is a clear commitment for call-back.

E. Barriers to Effective Verbal Communications

1) Sender or receiver not stating his or her name and/or work location when using a telephone or radio.

2) Sender attempting to communicate with someone already engaged in another conversation.

3) Sender stating too much information or multiple actions in one message.

4) Sender not giving enough information for the receiver to understand the message.

5) Sender not verifying receiver understood the message.

6) Receiver failing to ask for needed clarification of the message, if required.

7) Receiver taking action before the communication is complete.

8) Receiver not writing the message on paper, if there are several items (more than two) to remember.

9) Receiver mentally preoccupied with another task.

10) Message not being stated loudly enough to be heard.

11) Enunciating words poorly.

III. Communications Training for System Operators

Effective communication is one of the most important defenses in the prevention of errors and events. Training provides an opportunity to ensure that personnel know their company's requirements and expectations for verbal communications, and it also reinforces good communication practices through the use of drills and exercises.

Communications training can be based on company-specific policies and procedures for verbal communications. The goal of communications training is to ensure effective verbal communications during real-time operations. The following practices are provided for consideration in the development of training exercises and drills and for management observation/coaching involving verbal communications:

A. Classroom Training

1) Classroom training can focus on company-specific policies and procedures for verbal communications. The trainer wants to be clear on what communications protocols are expected to be followed, when they are expected to be followed, and by whom. The trainer also wants to emphasize the benefits of following the specific protocols.

2) Classroom training on effective communication is most thorough when it addresses the following: 1) basis for use (why it is used); 2) when to use specific communications protocols (provide specific examples); 3) roles and responsibilities for each participant (include the significance of active listening); and 4) behavior expectations of each participant.

3) Effective communication principles can be reinforced during system operator training simulations, exercises, or drills. Performance objectives or competencies can be established and measured as part of these activities. Feedback assessments (both self and instructor) can be part of the communications training process.

4) Management or peer observations (e.g., operator coaching session) can be utilized to determine if the tools for effective communication are practiced by personnel in the actual job environment. These observations provide an opportunity to recognize personnel who meet or exceed expectations for use of effective communication tools. They also provide an opportunity in a non-punitive environment to coach personnel who need to improve their use of communication tools. The observations can be considered to determine if changes or improvements are needed when training on communication tools.

5) Management involvement in system operator training, exercises, and drills can be used to provide feedback and encourage a strong communications program.

B. Communication Practices – The following beneficial practices are provided for consideration in the development or modification of training on effective communication:

1) Incorporate a "Communication Topic" as part of each continuing training cycle.

2) Ensure training on communication stresses effective, active listening. Even though the "Sender or Initiator" of three-part communication is responsible for ensuring the message is understood, the individual(s) receiving the message want to be engaged and actively listening for effective communication to occur.

3) Use quizzes or reminders administered by email or other online testing applications to emphasize key aspects of effective communication. This tool can also be used to provide feedback on department or group level understanding of key points.

4) Incorporate internal and external operating experience related to communication as part of initial and continuing training. The operating experience can be based on: 1) management observations; 2) performance trends; 3) review of tapes from actual communication, including system events where directives were provided; or 4) related events from other industries.

5) Use small groups or breakouts as part of training to conduct peer reviews of actual communication. Audio tapes of actual operators can be reviewed by small groups to identify proper communication and areas for improvement. In addition, system operators may opt to review and critique their own voice recordings to identify lessons learned and opportunities for improvement.

6) Conduct training seminars or communications workshops that involve operators and other personnel to educate all involved parties on the expectations for effective communication.

7) As part of training, incorporate videos that depict proper use of tools for effective communication. Videos depicting operators in "real world" situations demonstrating proper use of tools for effective communication can enhance buy-in by personnel. Videos can also be used to depict scenarios in which tools for effective communication are not properly used. Participants can critique or identify the area(s) for improvement in the use of the tools for effective communication.

8) Structure field trips or benchmark trips to other industries (e.g., nuclear plants, aviation control centers) that allow operators to listen to another perspective. This can help reinforce a good balance on when to use three-part communication.

IV. Performance Assessment

Successful implementation of verbal communications programs often includes the development and maintenance of a comprehensive series of controls and leadership practices that develop, reinforce, and maintain effective communication. Examples of some effective elements of control programs are listed below.

A. For many reasons the electric industry records most of its operational communications. These recordings provide a rich vehicle for assessment, feedback, and learning when coupled with periodic reviews of the recordings for the elements of effective communication.

B. In line with feedback and training programs, shift supervisors or operations leaders at many operating entities assess a specific number of hours of recordings or a specific number of recordings that may cover various topical areas (e.g., switching evolutions, AVR notifications, SPS notifications, etc.) within an established period of time (e.g., every quarter or month) for each of the operators under his or her leadership. Those leaders are then expected to share their reviews with the operators involved. Such feedback is often most effective when it is provided soon after an operational event has transpired. Some entities prefer such recording review sessions be made in an informal coaching session. Other entities have tied effective communication to the very formal aspect of annual performance goals and the resulting performance reviews. Periodic assessments, including grading or scoring of calls, can quickly provide needed feedback to ensure a system operator will be successful in achieving such a performance goal throughout the course of the year. Entities may choose to reflect that success in employee performance compensation.

C. Recognition Programs – Consider development of positive reinforcement programs that recognize good system operator communications.

D. System Operator Assessments – Some entities assess the following:

1) Was the operator following the company's communication policy?

2) When three-part communication was required, were each of the three elements of three-part communication evident?

3) If the receiver did not effectively repeat back the communication the first time, did the sender pursue the receiver until the receiver did repeat back the elements of the reliability directive?

4) How professional was the actual communication in both content and tone?

5) The focus of these reviews might involve more than the spoken word, since some entities also include reviewing the resulting field paperwork. Such reviews help organizations ensure good housekeeping and see that the complete company policy is being implemented.

E. Event Analysis

1) If an operating entity has a system event that triggers a Category 2 or higher event review in accordance with the NERC Events Analysis Process, or if the operating entity has any other event for which it wants to further assess its operations, this circumstance provides the operating entity an opportunity to delve into assessing the effectiveness of its communications.

2) When the system event's recordings are pulled and reviewed, it provides an opportunity for leaders, operators, and trainers to assess the effectiveness of their communications as related to that event and, in some cases, to access broader operating practices.

3) Communication often involves parties beyond the organizational structure of one operating entity. As such, when a third party (the receiver) of a communication has not facilitated effective communication (either by not following agreed-upon protocol or by unprofessionalism) this circumstance provides an opportunity for the reviewing leader to share his or her observations with the receiver's leader to enable learning across both operating entities.

V. Aids to Communication

A. Recorders – Typically used to preserve a record of conversations to assist in the review of incidents. Also used to check conversations to ensure communications are effective and appropriate.

B. System Operator Logs – Used as a knowledge transfer device between system operators in the same control room, as well as for management to respond to inquiries about situations that occurred days, weeks or even months afterward. Used in conjunction with all other forms of communication.

C. Checklists – Used as an aid to ensure consistency in the information contained in routine communications. A typical use of a checklist is during shift turnover of system operators to ensure appropriate operating information is communicated to the system operator coming on-shift.

Related Documents and Links:

1. *Electric Reliability Organization Event Analysis Process,* dated February 2012 ERO Event Analysis Process
2. *DOE Standard: Human Performance Improvement Handbook, Volume 2: Human Performance Tools for Individuals, Work Teams, and Management*; DOE-HDBK-1028-2009, dated June 2009 Human Performance Tools for Individuals, Work Teams, and Management
3. *Human Performance Tools for Workers: General Practice for Anticipating, Preventing, and Catching Human Error During the Performance of Work,* dated April 2006. Developed by the Institute of Nuclear Power Operations (INPO 06-002)

Revision History:

Date	Version Number	Reason / Comments
5/30/2012	1.0	Initial Version – *System Operator Verbal Communications*

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Standards Announcement

Project 2012-INT-05 – Interpretation of CIP-002-3 for OGE

Formal Comment Period Open: June 27 – July 27, 2012

Now Available

A formal comment period for the interpretation of **CIP-002-3** – Cyber Security – Critical Cyber Asset Identification is open through 8 p.m. Eastern on Friday, July 27, 2012.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, July 27, 2012.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will consider all comments and determine whether to make changes to the interpretation response. If significant changes are made to the interpretation response the drafting team will submit the interpretation response for quality review prior to the next posting. If significant changes are not made, the drafting team will post the interpretation for a 45-day comment period and initial ballot.

Background

Oklahoma Gas and Electric (OGE) submitted a request for interpretation of CIP-002-3 asking for clarification of Requirement R1.2.5 in relation to SmartGrid AMI functionality. Clarification was requested that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW and therefore it should not be included in the company's risk-based methodology.

Additional information is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Unofficial Comment Form for Interpretation of CIP-002-3, Requirement R1, for OGE (Project 2012-INT-05)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form to submit comments on the Interpretation of CIP-002-3, Requirement R1, for OGE (Project 2012-INT-05). The electronic comment form must be completed by 8 p.m. ET **July 27, 2012.**

http://www.nerc.com/filez/standards/2012-INT-05_Interpretation_CIP-002-3_OGE.html

If you have questions please contact Steven Noess at steven.noess@nerc.net or by telephone at 404.446.9691.

Background Information

In May 2011, the Standards Committee appointed a standing CIP Interpretation Drafting Team for the development of CIP Interpretations. A project team from the CIP Interpretation Drafting Team has reviewed OGE's request for interpretation and developed this interpretation pursuant to the NERC Guidelines for Interpretation Drafting Teams. (Available at: http://www.nerc.com/files/Guidelines_for_Interpretation_Drafting_Teams_Approved_April_2011.pdf)

The stated purpose of CIP-002-3 is, in part, to "provide a cyber security framework for the identification and protection of Critical Cyber Assets *to support reliable operation of the Bulk Electric System.*" (emphasis added). Paragraph 4 of the purpose specifies that CIP-002-3 "requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets *that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment."* (emphasis added).

Pursuant to CIP-002-3, Requirement R1, the Responsible Entity must identify and document a risk-based assessment methodology ("RBAM") and use the RBAM to identify its Critical Assets, if any. In determining which of its assets may constitute Critical Assets, the RBAM shall consider, pursuant to CIP-002-3, Requirement R1.2.5: "Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more."

To the extent something is "critical to automatic load shedding under a common control system capable of shedding 300 MW or more" for the purpose of supporting reliable operation of the Bulk Electric System, the RBAM shall consider that system or facility. The RBAM drives a facts- and circumstance-based determination, which is not dependent on technology or specific types of systems or facilities. The IDT acknowledges that AMI is one of several technologies that a Responsible Entity may consider in determining applicability under CIP-002-3. AMI is an example of a technology to consider under an RBAM.

The interpretation drafting team notes that Requirement R1.2 requires the RBAM to "consider" whether the assets described in Requirement R1.2.5 should be designated as Critical

Assets. Each year, during the annual approval required under Requirement R4, a Responsible Entity that owns an AMI system should re-consider whether its AMI system is a Critical Asset pursuant to Requirement R1.2.5.

Applying these requirements to the remote connect or disconnect functionality associated with advanced metering infrastructure (AMI), the drafting team concludes in its interpretation that AMI is not a Critical Asset under R1.2.5 so long as the AMI is not designed to or cannot, without human operator intervention, shed a load of 300MW or more.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Please review the request for an interpretation, the associated standard, and the draft interpretation and then answer the following questions.

1. Do you agree with this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

   ☒ Yes

   ☐ No

   Comments: Request clarification because the that last paragraph of the Response appears to contradict the prior paragraph

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When completed, email this form to:
laura.hussey@nerc.net.
For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard

Date submitted: 2/24/11

Contact information for person requesting the interpretation:

Name: John Rhea

Organization: OGE Energy Corp.

Telephone: 405-553-3445

E-mail: rheajd@oge.com

Identify the standard that needs clarification:

Standard Number (include version number): CIP-002-3

(example: PRC-001-1)

Standard Title: Cyber Security – Critical Cyber Asset Identification

Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.

OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.

The AMI Remote Disconnect function has no impact on OGE's ability to participate in SPP's load shedding program. The cost of compliance for OGE alone is in the millions of dollars without any significant benefit to the reliability of the Bulk Electric System.

Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation

The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.

Requirement Number and Text of Requirement

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Question

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to "SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality."

In its response, the Interpretation Drafting Team will answer whether a company's SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

Response

In evaluating OGE's request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity's risk-based assessment methodology ("RBAM") "shall consider" the assets described in Requirement R1.2.5 for identification as Critical Assets.

Each year, during the annual approval required under CIP-002-3, Requirement R4, a Responsible Entity must reevaluate whether it has systems or facilities, as specified in Requirement R1.2.5, that are "critical to automatic load shedding under a common control system capable of shedding 300 MW or more." If it does, pursuant to Requirement R1.2, the Responsible Entity must consider that asset for identification as a Critical Asset under its RBAM required by CIP-002-3, Requirement R1. If a system or facility is not "critical to" automatically shedding load, or the common

control system is not “capable of” shedding 300 MW or more, the asset may not be a Critical Asset.

Asset identification under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities. For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5.

Therefore, if a system or facility such as AMI meets the specifications of Requirement 1.2.5 (i.e., is both capable of shedding 300 MW or more and is set up and purposed to automatically shed load), the Responsible Entity should consider the system or facility for identification as a Critical Asset under its RBAM. Otherwise, the Responsible Entity is not required to consider the system or facility for identification as a Critical Asset.

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When completed, email this form to:
maureen.long@nerc.net
For questions about this form or for assistance in completing the form, call Maureen Long at 813-468-5998.

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard

Date submitted: 2/24/11

Contact information for person requesting the interpretation:

Name: John Rhea

Organization: OGE Energy Corp.

Telephone: 405-553-3445

E-mail: rheajd@oge.com

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(example: PRC-001-1)

Standard Title: Cyber Security – Critical Cyber Asset Identification

Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

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Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

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Identify the material impact associated with this interpretation:
Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard. The AMI Remote Disconnect function has no impact on OGE's ability to participate in SPP's load shedding program. The cost of compliance for OGE alone is in the millions of dollars without any significant benefit to the reliability of the Bulk Electric System.