NPCC, Inc.

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

NPCC Regional Standards Committee
Preliminary--Supplement for Meeting #13-1

Feb. 20, 2013 10:00 a.m. - 5:00 p.m.
Feb. 21, 2013 8:00 a.m. - 3:00 p.m.

FRCC Offices
3000 Bayport Drive
Suite 690
Tampa, FL 33607

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1. FERC Items of Interest

a. NERC's Notice of Withdrawal of BAL-004-1 - Time Error Correction filed on October 24, 2012 in Docket No. RM09-13-000 was uncontested and therefore became effective by operation of law on November 9, 2012. Reliability Standard BAL-004-1 is now inactive. Reliability Standard BAL-004-0 is currently effective and is unaltered by the withdrawal of BAL-004-1.
b. Sunshine Act Meeting--Dec. 20, 2012.
c. Official Data Request to Fulfill FERC Order No. 693 Requirements-Restoration of Nuclear Power Plant Offsite Power Sources Request for Data for the Fourth Quarter of 2012 (October 1-December 31, 2012).
d. January 2013 Open Meeting Summary.

FERC Items of Interest (continued)

Item	NOPR, Petition, Final Rule, Other	Title	Posted	Summary, Instructions, Dates
1.1	**Mandatory Reliability Standards For The Bulk Power System** **Docket No.** RM06-16-000	**Third Quarter 2012 Compliance Filing Of The North American Electric Reliability Corporation In Response To Paragraph 629 Of Order No. 693**	11/29/12	This filing reports information collected for the third quarter of 2012 to comply with FERC's March 16, 2007 Order directing 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.
1.2	**Notice Of Request For Comments And Technical Conference** **Docket No.** AD12-12-000	**Coordination between Natural Gas and Electricity Markets**	12/7/12	FERC will hold a technical conference Feb. 13, 2013 to elicit input pertaining to information sharing and communications issues between natural gas and electric power industry entities.
1.3	**Order** **Docket No.** RM10-11-001	**Order 764-A - Order On Rehearing And Clarification And Granting Motion For Extension Of Time**	12/20/12	On June 22, 2012, FERC issued the *Integration of Variable EnergyResources* Final Rule. Additionally, Edison Electric Institute (EEI) filed a motion to extend the period for compliance filings from September 11, 2013, to November 12, 2013. In this order, FERC affirms its basic determinations in Order No. 764, provides clarification, and grants EEI's request to extend the period for compliance filings.

Item	NOPR, Petition, Final Rule, Other	Title	Posted	Summary, Instructions, Dates
1.4	**Order** **Docket No.** NP11-238-001	**Order Denying Rehearing**	12/20/12	The order denies rehearing of FERC's July 2012 order, which approved a $19,500 penalty against the Southwestern Power Administration for violation of certain CIP Standards. The order reaffirms the legal finding in the July 2012 order that federal entities that act as users, owners, or operators of the bulk power system are subject to monetary penalties for violation of an approved Reliability Standard, in accordance with the enforcement authorities granted under Federal Power Act section 215. Violations of CIP Standards.
1.5	**Comments** **Docket No.** EL13-11-000; RD13-1-000	**Comments Of The North American Electric Reliability Corporation In Support Of The Western Electricity Coordinating Council's Motion For Designation Of Certain Commission Staff As Non-Decisional**	1/17/13	NERC files these comments in support of WECC's January 14, 2013 filing requesting that FERC designate certain staff from its Office of Energy Policy and Innovation non-decisional. NERC requests that FERC grant WECC's request to designate certain OEPI staff as non-decisional in the referenced proceedings.

2. **Posted NERC Projects--Additional Items**
   a. Project 2010-11 TPL Table 1, Footnote B--Webinar Jan. 8, 2013.
   b. Revisions to NERC Rules of Procedure Appendix 4D Posted in Anticipation of Board Meeting on January 30, 2013.

3. **NERC**

a. NERC Releases Long-Term, Winter Reliability Assessments--Nov. 29, 2012.
   1. 2012 Long-Term Reliability Assessment.
   2. Winter Reliability Assessment.

b. Reliability Issues Information Sharing Conference 2012--Presentations.

c. Reliability Issues Steering Committee.
   1. Reliability Issues Steering Committee Meeting--Dec. 17, 2012.
   2. Reliability Issues Steering Committee Teleconference--Jan. 24, 2013. Meeting materials can be accessed here.
      a. Reliability Issues for consideration Nomination Form for RISC January 24, 2013 Meeting.
   3. Reliability Issues Steering Committee Teleconference--Feb. 12, 2013.

d. NERC Standard Processes Manual Revisions to Implement SPIG Recommendations Industry Webinar Dec. 6, 2012--slides posted.

e. Standards Committee Meeting--Dec. 13, 2012.

f. Operating Committee Meeting--Dec. 12-13, 2012.

g. CIPC Meeting Dec. 12-13, 2012.

h. NERC Names New Chief Operating Officer, Vice President for Reliability Assessment and Performance Analysis. Mark Rossi joins NERC as Senior Vice President and Chief Operating Officer. Tom Burgess joins NERC as Vice-President and Director of Reliability Assessment and Performance Analysis.

i. Communications in Operations Conference Project 2007-02 Operating Personnel Communications Protocols--Feb. 14-15, 2013.

j. Electricity Sub-Sector Coordinating Council Meeting--Jan. 24, 2013.
   1. FERC NOPR RM12-22-000 Reliability Standards for Geomagnetic Disturbances (10/18/12) on the Agenda.

k. Compliance Committee Meeting--Feb. 6, 2013.
   1. Presentations.

l. Board of Trustees Meeting--Feb. 7, 2013.
   1. Presentations.

m. NERC Response on Cybersecurity Executive Order.

4. **NERC Standards Bulletins, NERC News, Lessons Learned**
   a. NERC News.
      1. NERC News November 2012.
      2. NERC News December 2012.
      3. NERC News January 2013.
   b. NERC Standards Bulletins.
      1. NERC Standards Bulletin Dec. 3-9, 2012.
      2. NERC Standards Bulletin Dec. 10-16, 2012.
      3. NERC Standards Bulletin Dec. 17-23, 2012.
      4. NERC Standards Bulletin Dec. 24-30, 2012.
      5. NERC Standards Bulletin Dec. 31, 2012 - Jan. 6, 2013.
      6. NERC Standards Bulletin Jan. 7-13, 2013.
      7. NERC Standards Bulletin Jan. 14-20, 2013.
      8. NERC Standards Bulletin Jan. 22-27, 2013.
      9. NERC Standards Bulletin Jan. 28 - Feb. 3, 2013.
      10. NERC Standards Bulletin Feb. 4-10, 2013.
      11. NERC Standards Bulletin Feb. 11-18, 2013.

5. **Other**
   a. RCC Sept. 12, 2012 Meeting Minutes--posted Nov. 30, 2012.
   b. NPCC Governmental/Regulatory Affairs Advisory Group Meeting--Nov. 27, 2012.
   c. Report on Opportunities for Improvement--Final Regional Entity Responses to NERC June 5, 2012 Letter on Follow-Up Actions Related to September 8, 2011 Outage Recommendations.
   d. NYISO 2013-2017 Strategic Plan.
   e. TFCO Nov. 29-30, 3012 Meeting minutes. BAL-003-1 Frequency Response and Bias discussed.

Appendix A (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 B

Concluded Ballots (in Meeting Materials Package)

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
1.	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
2.	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
3.	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
4.	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
5.	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
6.	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
7.	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
8.	Project 2009-06 - Facility Ratings	Cast Ballot	4/21/11	5/2/11	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
9.	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
10.	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
11.	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	----
12.	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
13.	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
14.	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%	----
15.	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
16.	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%	----
17.	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

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
18.	Project 2006-02 - Assess Transmission and Future Needs	Cast Ballot	7/13/11	7/22/11	Quorum: 94.33% Approval: 75.37%	----
19.	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
20.	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
21.	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
22.	Project 2006-06 - Reliability Coordination - IRO-002-3	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: 75.37% Approval: 93%	----
23.	Project 2006-06 - Reliability Coordination - IRO-005-4	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: 75.66% Approval: 93%	----
24.	Project 2006-06 - Reliability Coordination - IRO-014-2	Cast Non-Binding Poll Opinion	7/15/11	7/25/11	Quorum: 75.37% Approval: 89%	-----
25.	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
26.	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%	----

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
27.	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
28.	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
29.	Project 2007-07 - Vegetation Management	Recirculation Ballot	10/4/11	10/13/11	Quorum: 87.17% Approval: 86.25%	Yes 2/22/11
30.	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
31.	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
32.	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
33.	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
34.	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
35.	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

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)					Results of Ballot	RSC Recommend/Date
36.	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
37.	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
38.	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
39.	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
40.	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
41.	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 41 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 Results of Ballot column links to the Ballot Results)**						**Results of Ballot**	**RSC Recommend/Date**
42.	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
43.	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
44.	Project 2010-07 - Generator Requirements at the Transmission Interface--PRC-004-2.1		Recirculation Ballot	12/14/11	12/23/11		Yes 11/10/11
	FAC-001-1	Quorum: 88.48% Approval: 90.10%					
	FAC-003-3	Quorum: 87.17% Approval: 85.38%					
	FAC-003-X	Quorum: 86.91% Approval: 85.03%					
		Quorum: 86.65% Approval: 96.43%					

https://standards.nerc.net/Ballots.aspx (clicking in the Results of Ballot column links to the Ballot Results)						Results of Ballot	RSC Recommend/Date
	PRC-004-2.1a						

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	
45.	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2		Successive Ballots	1/3/12	1/12/12	1/9/12 TOP-001-2--No TOP-002-3--Yes TOP-003-2--Yes	
	TOP-001-2	Quorum: 82.04% Approval: 59.93%					
	TOP-002-3	Quorum: 82.04% Approval: 77.08%					
	TOP-003-2	Quorum: 82.04% Approval: 78.95%					
46.	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

47.	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2		Non-Binding Polls	1/9/12	1/18/12 Extended to 1/19/12	----	
	TOP-001-2	Quorum: 81.50% Approval: 67.61%					
	TOP-002-3	Quorum: 76.41% Approval: 71.42%					
	TOP-003-2	Quorum: 81.50% Approval: 70.28%					

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)					**Results of Ballot**	**RSC Recommend/Date**
48.	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
49.	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
50.	Project 2010-07 - Generator Requirements at the Transmission Interface--PRC-004-2.1	Recirculation Ballot	12/14/11	12/23/11		Yes 11/10/11

	https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)				**Results of Ballot**	**RSC Recommend/Date**
	FAC-001-1 FAC-003-3 FAC-003-X PRC-004-2.1a				Quorum: 88.48% Approval: 90.10% Quorum: 87.17% Approval: 85.38% Quorum: 86.91% Approval: 85.03% Quorum: 86.65% Approval: 96.43%	
51.	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

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)					**Results of Ballot**	**RSC Recommend/Date**
52.	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
53.	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%	----
54.	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	2/7/12 COM-001-02--No COM-002-3--Yes IRO-001-3--Yes	
		Successive Ballot	Non-binding Poll Results			
	COM-001-2	Quorum: 81.82% Approval: 54.64%	Quorum: 80.35% Approval: 71.35%			
	COM-002-3	Quorum: 82.11% Approval: 80.62%	Quorum: 80.06% Approval: 90.86%			
	IRO-001-3	Quorum: 81.82% Approval: 80.21%	Quorum: 79.77% Approval: 84.69%			
55.	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%	----

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)						Results of Ballot	RSC Recommend/Date
56.	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
57.	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
58.	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
59.	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%					
60.	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
61.	Project 2007-03 - Real-time Transmission Operations - TOP-001 through TOP-008 and PER-001		Successive Ballots and Non-binding Polls	4/11/12	4/20/12		
		Successive Ballot	Non-binding Poll Results				

	https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)					**Results of Ballot**	**RSC Recommend/Date**
	TOP-001-2	Quorum: 78.28% Approval: 75.44%	Quorum: 77.21% Approval: 69.84%				
	TOP-002-3	Quorum: 78.02% Approval: 87.22%					
	TOP-003-2	Quorum: 78.28% Approval: 80.11%	Quorum: 77.48% Approval: 67.64%				
62.	Project 2007-17 Protection System Maintenance and Testing - PRC-005		Successive Ballot	3/19/12	3/28/12	Quorum: 84.32% Approval: 73.93%	Yes 3/19/12
63.	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%					

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)				Results of Ballot	RSC Recommend/Date
64.	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1		4/6/12	4/16/12	No 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%		
65.	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: 79.36% Approval: 80.79%			

https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" column links to the Ballot Results)				Results of Ballot	RSC Recommend/Date	
64.	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1			4/6/12	4/16/12	No 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%			
66.	Project 2008-06 - Cyber Security Order 706 Version 5 CIP		Successive Ballots	5/11/12	5/21/12	See Table below / Abstain 5/17/12

For Item 67 above--

CIP-002-5 Cyber Security — BES Cyber System Identification	Quorum: 86.21% Approval: 36.58%
CIP-003-5 Cyber Security — Security Management Controls	Quorum: 87.04% Approval: 61.45%

CIP-004-5 Cyber Security — Personnel and Training	Quorum: 86.98% Approval: 39.42%
CIP-005-5 Cyber Security — Electronic Security Perimeter(s)	Quorum: 86.57% Approval: 55.93%
CIP-006-5 Cyber Security — Physical Security	Quorum: 86.80% Approval: 39.09%
CIP-007-5 Cyber Security — Systems Security Management	Quorum: 86.60% Approval: 46.49%
CIP-008-5 Cyber Security — Incident Reporting and Response Planning	Quorum: 85.77% Approval: 68.24%
CIP-009-5 Cyber Security — Recovery Plans for BES Cyber Assets and Systems	Quorum: 86.60% Approval: 61.13%
CIP-010-1 Cyber Security — Configuration Change Management	Quorum: 85.98% Approval: 48.67%
CIP-011-1 Cyber Security — Information Protection	Quorum: 85.98% Approval: 59.15%
CIP V5 Implementation Plan	Quorum: 84.71% Approval: 65.85%
CIP V5 Definitions	Quorum: 83.68% Approval: 47.23%

67.	Project 2010-07 - Generator Requirements at the Transmission Interface		Recirculation Ballot	4/24/12	5/3/12		
	FAC-003-3	Quorum: 81.72% Approval: 87.34%					
	FAC-003-X	Quorum: 81.94% Approval: 87.32%					
	PRC-005-1.1a	Quorum: 90.44% Approval: 93.23%					
68.	Project 2009-01 - Disturbance and Sabotage Reporting		Successive Ballot	5/15/12	5/24/12	Quorum: 84.43% Approval: 46.18%	
			Non-binding Poll Results			Quorum: 79.95% Supportive Approvals: 52.67%	
69.	Project 2007-03 - Real-time Transmission Operations		Recirculation Ballots	4/27/12	5/6/12		TOP-001 Abstain 4/19/12 TOP-002 Yes 4/19/12 TOP-003 Yes 4/19/12
	TOP-001-2	Quorum: 79.36% Approval: 76.84%					
	TOP-002-3	Quorum: 79.36% Approval: 88.11%					
	TOP-003-2	Quorum: 79.36% Approval: 80.79%					

70.	Project 2007-02 - Operating Personnel Communication Protocols	Initial Ballot	6/11/12	6/20/12	Quorum: 84.14% Approval: 21.11%	No 6/13/12
		Non-binding Poll			Quorum: 81.01% Approval: 28.78%	
71.	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/12	4/30/12	Quorum: 90.96% Approval: 80.08%	Yes 3/16/12
72.	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/12	4/30/12	Quorum: 92.68% Approval: 94.61%	Yes 3/16/12
73.	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Successive Ballot	6/18/12	6/27/12	Quorum: 85.98% Approval: 68.22%	Yes 6/26/12
74.	Project 2007-06 - System Protection Coordination	Initial Ballot	6/26/12	7/5/12	Quorum: 84.24% Approval: 23.82%	No 6/27/12
		Non-binding Poll			Quorum: 82.26% Approval: 25.19%	
75.	Project 2007-17 Protection System Maintenance and Testing - PRC-005	Successive Ballot	6/18/12	6/27/12	Quorum: 79.46% Approval: 79.00%	Yes 6/22/12
		Non-binding Poll			Quorum: 75.00% Approval: 70.21%	

76.	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3		Successive Ballot (COM-001-2) Recirculation Ballot (COM-002-3, IRO-001-3)	6/27/12	Orig.--7/6/12 COM-001-2 Extended to 7/9/12	No Consensus 7/5/12
	COM-001-2	Successive Ballot	Non-binding Poll (All)			
		Quorum: 75.37% Approval: 72.16%	Quorum: 75.37% Approval: 73.71%			
	COM-002-3	Recirculation Ballot	Quorum: 84.16% Approval: 79.16%			
		Quorum: 85.34% Approval: 81.71%				
	IRO-001-3	Recirculation Ballot	Quorum: 83.87% Approval: 86.91%			
		Quorum: 85.04% Approval: 81.72%				
77.	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	Quorum: 80.39% Approval: 79.28%	7/20/12	7/30/12	No 7/20/12
		Non-binding Poll	Quorum: 78.26% Approval: 76.07%			
78.	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	Quorum: 83.11% Approval: 54.16%	7/24/12	8/2/12	No 7/20/12
79.	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	Quorum: 79.21% Approval: 87.78%	8/23/12	9/4/12	Yes 2/22/10

80.	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	Quorum: 90.97% Approval: 69.81%	7/18/12	7/27/12	Yes 6/26/12
		Non-binding Poll	Quorum: 81.31% Approval: 60.93%			
81.	Project 2007-17 Protection System Maintenance and Testing - PRC-005	Successive Ballot	Quorum: 78.11% Approval: 80.31%	8/17/12	8/27/12	Yes 6/22/12
82.	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations)	Initial Ballot	Quorum: 86.71% Approval: 37.68%	8/29/12	9/7/12	Yes 9/5/12
		Non-binding Poll	Quorum: 84.17% Approval: 37.36%			
83.	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	Quorum: 78.57% Approval: 73.02%	10/10/12	10/19/12 (changed to 10/23/12)	
84.	Project 2006-06 - Reliability Coordination	Recirculation Ballot	Quorum: 80.35% Approval: 75.01%	9/6/12	9/17/12	
85.	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	Quorum: 85.36% Approval: 87.34%	9/12/12	9/21/12	
86.	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot and	Quorum: 77.70% Approval: 50.57%	9/11/12	9/20/12	Yes 9/15/12
		Non-binding Poll	Quorum: 84.05% Approval: 54.07%			

87.	Project 2009-01 - Disturbance and Sabotage Reporting - CIP-001 and EOP-004	Successive Ballot	Quorum: 78.54% Approval: 63.40%	9/18/12	9/27/12	No Consensus 9/27/12
		Non-binding Poll	Quorum: 72.59% Approval: 63.05%			
88.	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)	Successive Ballot		10/1/12	10/10/12	Yes 10/4/12

CIP-002-5 Cyber Security — BES Cyber System Identification	Quorum: 80.58% Approval: 74.85%
CIP-003-5 Cyber Security — Security Management Controls	Quorum: 80.37% Approval: 89.50%
CIP-004-5 Cyber Security — Personnel and Training	Quorum: 80.58% Approval: 85.58%
CIP-005-5 Cyber Security — Electronic Security Perimeter(s)	Quorum: 80.58% Approval: 89.46%
CIP-006-5 Cyber Security — Physical Security	Quorum: 80.58% Approval: 92.11%
CIP-007-5 Cyber Security — Systems Security Management	Quorum: 80.58% Approval: 87.73%
CIP-008-5 Cyber Security — Incident Reporting and Response Planning	Quorum: 80.58% Approval: 91.74%
CIP-009-5 Cyber Security — Recovery Plans for BES Cyber Assets and Systems	Quorum: 80.58% Approval: 91.73%

CIP-010-1 Cyber Security — Configuration Change Management	Quorum: 80.58% Approval: 84.60%
CIP-011-1 Cyber Security — Information Protection	Quorum: 80.58% Approval: 92.90%
CIP V5 Implementation Plan	Quorum: 78.93% Approval: 94.00%
CIP V5 Definitions	Quorum: 79.13% Approval: 91.59%

89.	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	Quorum: 87.23% Approval: 63.17%	10/3/12	10/12/12	Yes 10/4/12
90.	Project 2007-09 - Generator Verification	Successive Ballot		10/19/12	10/31/12	
		Non-binding Poll				

MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions and Plant Volt/Var Control Functions	Successive Ballot	Quorum: 75.55% Approval: 76.50%
	Non-binding Poll	Quorum: 75.88% Approval: 77.10%
PRC-024-1 – Generator Performance During Frequency and Voltage Excursions	Successive Ballot	Quorum: 75.00% Approval: 57.24%
	Non-binding Poll	Quorum: 75.40% Approval: 52.72%

MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	Successive Ballot	Quorum: 83.61% Approval: 68.31%
	Non-binding Poll	Quorum: 77.94% Approval: 64.24%
MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	Successive Ballot	Quorum: 82.34% Approval: 71.53%
	Non-binding Poll	Quorum: 78.06% Approval: 68.93%
PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	Successive Ballot	Quorum: 82.07% Approval: 70.64%
	Non-binding Poll	Quorum: 78.51% Approval: 63.63%

91.	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	Quorum: 85.11% Approval: 90.34%	9/28/12	10/8/12	Yes 2/22/10
92.	Project 2007-17 Protection System Maintenance and Testing - PRC-005	Recirculation Ballot	Quorum: 81.08% Approval: 80.51%	10/15/12	10/24/12	Yes 6/22/12
93.	Project 2009-01 - Disturbance and Sabotage Reporting - CIP-001 and EOP-004	Recirculation Ballot	Quorum: 85.14% Approval: 71.39%	10/24/12	11/2/12	
		Non-binding Poll	Quorum: 78.93% Approval: 71.04%			

94.	Project 2007-12 - Frequency Response	Successive Ballot	Quorum: 82.04% Approval: 76.08%	10/26/12	11/6/12 (Changed from 11/5/12 because of Hurricane Sandy)	Yes 11/5/12
		Non-binding Poll	Quorum: 76.28% Approval: 76.30%			
95.	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)	Recirculation Ballots	See Table Below	10/26/12	11/5/12	Yes 10/4/12
		Non-binding Poll for VRFs and VSLs	Quorum: 75.41% Approval: 83.82%			

CIP-002-5 Cyber Security — BES Cyber System Identification	Quorum: 85.33% Approval: 78.59%
CIP-003-5 Cyber Security — Security Management Controls	Quorum: 85.33% Approval: 92.75%
CIP-004-5 Cyber Security — Personnel and Training	Quorum: 85.54% Approval: 89.73%
CIP-005-5 Cyber Security — Electronic Security Perimeter(s)	Quorum: 85.54% Approval: 93.73%
CIP-006-5 Cyber Security — Physical Security	Quorum: 85.54% Approval: 95.53%
CIP-007-5 Cyber Security — Systems Security Management	Quorum: 85.54% Approval: 91.79%

CIP-008-5 Cyber Security — Incident Reporting and Response Planning	Quorum: 85.54% Approval: 95.47%
CIP-009-5 Cyber Security — Recovery Plans for BES Cyber Assets and Systems	Quorum: 85.33% Approval: 94.60%
CIP-010-1 Cyber Security — Configuration Change Management	Quorum: 85.54% Approval: 88.99%
CIP-011-1 Cyber Security — Information Protection	Quorum: 85.54% Approval: 95.67%
CIP V5 Implementation Plan	Quorum: 83.47% Approval: 94.91%
CIP V5 Definitions	Quorum: 83.47% Approval: 93.23%

96.	Project 2010-11 - TPL Table 1, Footnote B	Initial Ballot	Quorum: 80.17% Approval: 56.18%	11/9/12	11/19/12	
97.	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	Quorum: 84.81% Approval: 72.57%	11/26/12	12/5/12	No 12/5/12
98.	Project 2013-02 - Paragraph 81	Initial Ballot	Quorum: 75.77% Approval: 96.45%	11/30/12	12/10/12	Yes 12/10/12

99.	Project 2007-02 Operating Personnel Protocols - COM-003	Successive Ballot	Quorum: 76.78% Approval: 53.57%	12/4/12	12/13/12	No Consensus 12/13/12
		Non-binding Poll	Quorum: 77.22% Approval: 57.91%			
100.	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	Quorum: 76.47% Approval: 33.23%	12/7/12	12/17/12	No 12/17/12
		Non-binding Poll	Quorum: 75.58% Approval: 34.80%			
101.	Interpretation 2012-INT-05	Initial Ballot	Quorum: 84.50% Approval: 95.60%	12/11/12	12/20/12	Yes 12/19/12
102.	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	Quorum: 83.24% Approval: 84.48%	12/11/12	12/20/12	Yes 12/19/12
103.	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	Initial Ballot	Quorum: 83.38% Approval: 22.06%	1/4/13	1/14/13	No 1/11/13
		Non-binding Poll	Quorum: 81.93% Approval: 24.39%			
104.	Project 2010-11 - TPL Table 1, Footnote B	Successive Ballot	Quorum: 85.47% Approval: 65.77%	1/2/13	1/11/13	No Consensus 1/11/13
105.	Project 2007-09 - Generator Verification - MOD-025-2, MOD-026-1, MOD-027-1, and PRC-019-1	Recirculation Ballot		12/12/12	12/21/12	
		MOD-025-2	Quorum: 86.89% Approval: 73.06%			

		MOD-026-1	Quorum: 79.00% Approval: 79.36%			
		MOD-027-1	Quorum: 86.68% Approval: 74.27%			
		PRC-019-1	Quorum: 85.87% Approval: 73.63%			
106.	Project 2007-09 - Generator Verification - PRC-024-1	Successive Ballot	Quorum: 77.85% Approval: 60.47%	1/2/12	1/11/13	Yes 1/11/13
		Non-Binding Poll	Quorum: 76.05% Approval: 56.02%			
107.	Project 2007-12 - Frequency Response	Recirculation Ballot	Quorum: 86.19% Approval: 76.53%	12/12/12	12/21/12	
108.	Project 2013-02 - Paragraph 81	Recirculation Ballot	Quorum: 84.60% Approval: 95.22%	1/8/13	1/17/13	
109.	Interpretation 2012-INT-05	Recirculation Ballot	Quorum: 87.13% Approval: 99.09%	1/14/13	1/23/13	
110.	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	Quorum: 85.90% Approval: 85.57%	1/18/13	1/28/13	
111.	Project 2010-11 - TPL Table 1, Footnote B	Recirculation Ballot	Quorum: 88.55% Approval: 69.63%	1/22/13	1/31/13	

112.	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	Quorum: 85.67% Approval: 77.61%	1/22/13	1/31/13	

Appendix C

Comment Forms Submitted (in Meeting Materials Package)

1.	Standards Project Prioritization Reference Document and Tool	Comment Form	1/21/11	2/10/11
2.	Project 2007-12 - Frequency Response	Comment Form	2/4/11	3/7/11
3.	Project 2007-07 - Vegetation Management - FAC-003	Comment Form	1/27/11	2/28/11
4.	Project 2007-23 - Violation Severity Levels	Comment Form	1/20/11	2/18/11
5.	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Comment Form	1/18/11	3/7/11
6.	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	Comment Form (no comments submitted)	1/10/11	2/24/11
7.	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	Comments	2/4/11	2/18/11
8.	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	Comments	2/4/11	2/18/11
9.	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	Comments	2/11/11	3/4/11

10.	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	Comments	2/4/11	2/18/11
11.	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	Comments	2/14/11	3/7/11
12.	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	Comment Form	3/17/11	5/2/11
13.	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	Comment Form	3/29/11	4/28/11
14.	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Comment Form	2/16/11	4/4/11
15.	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments	Comments (No comments submitted)	3/1/11	4/15/11
16.	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Comments	3/1/11	4/15/11
17.	Project 2010-07 - Generator Requirements at the Transmission Interface	Informal Comment Period	3/4/11	4/4/11
18.	Project 2009-01 - Disturbance and Sabotage Reporting	Comment Form	3/9/11	4/8/11
19.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Comment Form	4/13/11	5/12/11
20.	Project 2010-17 - Definition of Bulk Electric System	Comment Form	4/28/11	5/27/11
21.	Project 2006-02 - Assess Transmission and Future Needs	Comment Form	4/18/11	5/31/11
22.	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	Comment Form	4/26/11	6/9/11
23.	Project 2010-17 - Definition of Bulk Electric System	Comment Form	5/11/11	6/10/11
24.	Rules of Procedure Development Team: BES Definition Exception Process	Comment Form	5/11/11	6/10/11
25.	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	Comments	5/20/11	6/10/11
26.	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	Comments	5/20/11	6/10/11

27.	CAN-0030--Draft CAN-0030 Attestations	Comments	5/20/11	6/10/11
28.	CAN-0039--Draft CAN-0039 DOE Form 407	Comments	5/20/11	6/10/11
29.	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)	Comment Form	6/10/11	7/11/11
30.	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	Comment Form	6/15/11	7/15/11
31.	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	Comment Form	6/15/11	8/1/11
32.	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
33.	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
34.	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)
35.	Compliance Application Notice (CAN) Process	Comment Form	8/15/11	9/6/11
36.	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	Comment Form	8/15/11	9/6/11

37.	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	Comment Form	8/26/11	10/10/11
38.	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
39.	NERC 2012-2014 Reliability Standards Development Plan	Comment Form	9/12/11	9/26/11
40.	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
41.	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
42.	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
43.	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Comment Form	10/3/11	11/16/11
44.	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Comment Form	10/4/11	11/17/11
45.	Project 2010-07 - Generator Requirements at the Transmission Interface	Comment Form	10/5/11	11/18/11
46.	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
47.	CAN-0030--Attestations	No Comments	10/19/11	11/9/11
48.	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Comment Form	10/12/11	11/21/11
49.	CAN-0010--Definition of "Annual" and Implementation of	Sent Comment Form to	10/10/11	10/31/11

	Annual Requirements	cancomments@nerc.net		
50.	CAN-0011--PRC-005-1 R2: New Equipment	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
51.	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
52.	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	No Comments	10/10/11	10/31/11
53.	CAN-0015--Unavailability of NERC Software Tools	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
54.	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	No Comments	10/10/11	10/31/11
55.	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
56.	CAN-0026--TOP-006 R3 Protection Relays	Sent Comment Form to cancomments@nerc.net	10/10/11	10/31/11
57.	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	No Comments	10/10/11	10/31/11
58.	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)
59.	CAN-000040 - BAL-003 Frequency Bias Calculation	No Comments	11/2/11	11/23/11
60.	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	Comment Form (submitted to cancomments@nerc.net)	11/2/11	11/23/11
61.	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	No Comments	11/22/11	12/14/11

62.	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
63.	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
64.	Proposed Changes to the NERC Rules of Procedure and Associated Appendices	No Comments	11/7/11	12/22/11
65.	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
66.	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding (NPCC Website Link)	No Comments	11/22/11	12/22/11
67.	Order 754 - Request for Data or Information	Comment Form	12/22/11	2/6/11
68.	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Comment Form	1/4/12	2/3/12
69.	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
70.	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	No Comments	1/23/12	3/9/12
71.	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	No Comments	1/23/12	3/9/12
72.	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Comment Form	2/8/12	3/23/12
73.	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Comment Form	2/8/12	3/23/12
74.	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Comment Form	2/8/12	3/23/12

75.	NERC Functional Model Demand Response Functions and Entities	No Comments	2/13/12	3/14/12
76.	Project 2007-17 Protection System Maintenance and Testing - PRC-005	Comment Form	2/28/12	3/28/12
77.	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1	Comment Form	2/29/12	3/29/12
78.	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1	Comment Form	2/29/12	4/16/12
79.	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3	Comment Form	3/9/12	4/9/12
80.	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a	Comment Form	3/2/12	4/16/12
81.	Project 2007-03 - Real-time Transmission Operations	Comment Form	3/22/12	4/20/12
82.	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	Comment Form A Comment Form B Comment Form C Comment Form D	4/12/12	5/21/12
83.	Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for SPCS	Comment Form	4/24/12	5/4/12
84.	Project 2009-01 - Disturbance and Sabotage Reporting	Comment Form	4/25/12	5/24/12
85.	Adequate Level of Reliability Revised Definition and Associated Documents	Comment Form	4/25/12	6/25/12
86.	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Comment Form	5/7/12	6/20/12
87.	Project 2007-06 - System Protection Coordination	Comment Form	5/21/12	7/5/12

88.	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Comment Form	5/22/12	6/27/12
89.	Order 754	Comment Form	5/11/12	6/25/12
90.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Comment Form	5/29/12	6/27/12
91.	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	Comment Form	5/7/12	7/6/12
92.	Project 2007-12 Frequency Response Technical Conferences	Comment Form (individual member submissions)	5/30/12	6/15/12
93.	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	Comment Form	6/4/12	7/3/12
94.	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	Comment Form	6/7/12	7/6/12
95.	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	Comment Form	6/19/12	7/9/12
96.	Standard Processes Manual Revisions to Implement SPIG Recommendations	Comment Form	6/20/12	7/19/12
97.	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee	Comment Form	6/20/12	7/19/12 Changed to 7/20/12
98.	Interpretation of 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Comment Form	6/27/12	7/27/12
99.	Project 2011-INT-02 - Rapid Revision to Address Interpretation of VAR-002 for Constellation	Comment Form	7/18/12	7/27/12
100.	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Comment Form	6/14/12	7/30/12
101.	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Comment Form	6/19/12	8/2/12
102.	Reliability Guideline: System	Comments Submitted to	6/26/12	8/10/12

	Operator Verbal Communications – Current Industry Practices	reliabilityguidelinecomments@nerc.net		
103.	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Comment Form	7/25/12	9/4/12
104.	Project 2006-02 - Assess Transmission and Future Needs	Data Request for Transmission Planners	7/31/12	8/30/12
105.	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12	Comment Form	7/31/12	8/29/12
106.	Project 2013-02 - Paragraph 81	Comment Form	8/3/12	9/4/12
107.	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Comment Form	7/27/12	8/27/12
108.	Definition of Adequate Level of Reliability	Comment Form	8/15/12	9/13/12
109.	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)	Comment Form	7/25/12	9/7/12
110.	2013-2015 Reliability Standards Development Plan	Comment Form	8/17/12	9/18/12
111.	Project 2007-02 - Operating Personnel Communications Protocols	Comment Form	8/22/12	9/20/12
112.	Standard Process Manual Revisions to Implement SPIG Recommendations	Comment Form	8/29/12	10/12/12
113.	Project 2009-01 - Disturbance and Sabotage Reporting	Comment Form	8/29/12	9/27/12
114.	PRC-006-SPP-01 - SPP Automatic Underfrequency Load Shedding	Comment Form	8/15/12	9/28/12
115.	Regional Reliability Standards - MRO Standards Process Manual		8/28/12	10/11/12
116.	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	9/11/12	10/10/12
117.	Revisions to Outstanding VRFs and VSLs	Comment Form	9/5/12	10/19/12
118.	Project 2013-01 - Cold Weather Preparedness	Comment Form	9/25/12	10/24/12

119.	Regional Reliability Standard PRC-006-SPP-01	No Comments Submitted	8/15/12	9/28/12
120.	Project 2007-09 - Generator Verification	No Comments Submitted	9/28/12	10/29/12
121.	IRO-006-WECC-2	No Comments Submitted	10/3/12	11/16/12
122.	Project 2010-17 - Definition of Bulk Electric System	No Comments Submitted	10/4/12	11/5/12
123.	Project 2007-12 - Frequency Response	Comment Form	10/5/12	11/7/12 (Changed from 11/5/12 because of Hurricane Sandy)
124.	Project 2010-11 - TPL Table 1, Footnote B	Comment Form	10/5/12	11/19/12
125.	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 (VRFs and VSLs)	10/26/12	11/7/12 (Changed from 11/5/12 because of Hurricane Sandy)
126.	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Comment Form	10/5/12	11/7/12 (Changed from 11/5/12 because of Hurricane Sandy)
127.	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Comment Form	10/22/12	12/5/12
128.	Project 2013-02 - Paragraph 81	Comment Form	10/25/12	12/10/12
129.	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Comment Form	11/6/12	12/20/12
130.	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Comment Form	11/9/12	12/10/12
131.	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Comment Form	11/9/12	12/10/12
132.	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	Comment Form	11/14/12	12/13/12
133.	Project 2007-06 - System	Comment Form	11/16/12	12/17/12

	Protection Coordination			
134.	Standard Processes Manual to Implement SPIG Revisions	Comment Form	11/21/12	12/20/12
135.	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	Comment Form	11/30/12	1/14/13
136.	Project 2010-11 - TPL Table 1, Footnote B	Comment Form	12/10/12	1/11/13
137.	Project 2007-09 - Generator Verification - PRC-024-1	Comment Form	12/12/12	1/11/13
138.	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices	Comment Form (to be sent to reliabilityguidlinecomments@nerc.net)	12/20/12	2/4/13

Appendix D

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 11-16-11); (Revised 6-15-12)	SS1	TT1	UU1	
8.	CAN-0012: Completion of Periodic Activity Requirements During Implementation Plan (Revised); (Revised 6-15-12)	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	
8.	DRAFT CAN-0034: EOP-002 R1, IRO-001 R2 and TOP-001 R1 Use of Authority Letters	SS2	TT2	UU2	
9.	DRAFT CAN-0038: PER-002 R4 Training Hours Removed from the development process 5/18/12.	VV2	WW2	XX2	
10.	DRAFT CAN-0019 CIP-007 R3.2 Implementation of Software Security Patches or Upgrades	YY2	ZZ2	AAA2	

11.	DRAFT CAN-0023 CIP-005 R3 CIP-006 R6 Logging System Failures	BBB2	CCC2	DDD2	

From: Elizabeth Heenan
To: reg_corresp_notif
Subject: NERC: Withdrawal of BAL-004-1 - Time Error Correction
Date: Wednesday, December 05, 2012 4:41:34 PM

To NERC Management and Regional Entity Executives,

Please be advised that NERC's Notice of Withdrawal of BAL-004-1 – Time Error Correction filed on October 24, 2012 in Docket No. RM09-13-000 was uncontested and therefore became effective by operation of law on November 9, 2012. Reliability Standard BAL-004-1 is now inactive. Reliability Standard BAL-004-0 is currently effective and is unaltered by the withdrawal of BAL-004-1.

Thank you,

Elizabeth Heenan
Legal Assistant, Legal and Regulatory Affairs
North American Electric Reliability Corporation
1325 G Street NW, Suite 600
Washington, DC 20005
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elizabeth.heenan@nerc.net
Reliability | Accountability

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

December 13, 2012

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	December 20, 2012 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://www.ferc.gov using the eLibrary link, or may be examined in the Commission's Public Reference Room.

988TH - MEETING

REGULAR MEETING

December 20, 2012

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD02-1-000	Agency Business Matters
A-2	AD02-7-000	Customer Matters, Reliability, Security and Market Operations
		ELECTRIC
E-1	RM10-11-001	Integration of Variable Energy Resources
E-2	EL11-44-001	Iberdrola Renewables, Inc., PacificCorp, NextEra Energy Resources, LLC, Invenergy Wind North America LLC, and Horizon Wind Energy LLC v. Bonneville Power Administration
E-3	EL11-44-002	Iberdrola Renewables, Inc., PacifiCorp, NextEra Energy Resources, LLC, Invenergy Wind North America LLC, and Horizon Wind Energy LLC v. Bonneville Power Administration
E-4	RM11-12-000	Availability of E-Tag Information to Commission Staff
E-5	RM12-6-000 RM12-7-000	Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure
E-6	OMITTED	
E-7	RR12-8-000	North American Electric Reliability Corporation
E-8	NP11-238-001	North American Electric Reliability Corporation
E-9	RM12-9-000	Regional Reliability Standard PRC-006-SERC-01-Automatic Underfrequency Load Shedding Requirements
E-10	OMITTED	

E-11	ER13-178-000	Southwest Power Pool, Inc.
E-12	ER13-207-000	City of Colton, California
E-13	ER13-168-000	California Independent System Operator Corporation
E-14	ER13-218-000	California Independent System Operator Corporation
E-15	ER13-219-000	California Independent System Operator Corporation
E-16	ER13-49-000	Valley Electric Association, Inc.
E-17	EC12-119-000	FirstEnergy Generation Corp. and American Transmission System, Incorporated
E-18	OMITTED	
E-19	OMITTED	
E-20	OMITTED	
E-21	OMITTED	
E-22	EL12-109-000	Avalon Wind, LLC, Avalon Wind 2, LLC, Catalina Solar, LLC, Catalina Solar 2, LLC, Pacific Wind Lessee, LLC, Pacific Wind 2, LLC, Valentine Solar, LLC, and EDF Renewables Development, Inc.
E-23	OMITTED	

GAS

G-1	RP11-2061-002 RP11-2061-003	Northern Natural Gas Company
G-2	RP12-814-000	Gulf Crossing Pipeline Company LLC
G-3	RP12-820-000	Texas Gas Transmission, LLC
G-4	RP12-813-000	Gulf South Pipeline Company, LP
G-5	OR12-27-000	Enbridge Pipelines (Southern Lights) LLC

HYDRO

H-1	P-13213-004 P-13214-004	Lock 14 Hydro Partners, LLC Lock 12 Hydro Partners, LLC
H-2	P-14354-001	Utah Independent Power, Inc.

H-3	HB81-09-2-002	Hudson River-Black River Regulating District, Erie Boulevard Hydropower L.P., Curtis/Palmer Hydroelectric Co., South Glens Falls Limited Partnership, et al., Northern Electric Power Co., et al., Fort Miller Associates, Stillwater Hydro Associates, New York State Electric & Gas Corp., Albany Engineering Corporation, and Green Island Power Co.

CERTIFICATES

C-1	RM12-11-000	Revisions to the Auxiliary Installations, Replacement Facilities, and Siting and Maintenance Regulations
C-2	CP12-25-000	Brian Hamilton v. El Paso Natural Gas Company
C-3	CP12-72-000	Dominion Transmission, Inc.

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit www.CapitolConnection.org or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

From:	Elizabeth Heenan
To:	reg_corresp_notif
Subject:	FERC: Two Orders, News Release on BES Defintion, and Sunshine Meeting Summary
Date:	Thursday, December 20, 2012 4:56:36 PM
Attachments:	Order_on_Rehearing_and_Clar_Int_Variable_Energy_Resources_2012.12.20.pdf News_Release_Definition_BES_2012.12.20.pdf Order_Revisions_BES_2012.12.pdf

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To NERC Management and Regional Entity Executives:

Attached please find an Order on Revisions to ERO Definition of Bulk Electric System and Rules of Procedure in Docket Nos. RM12-6-000 and RM12-7-000, and an Order on Rehearing and Clarification and Granting Motion for Extension of Time on the Integration of Variable Energy Resources in Docket No. RM10-11-001. These orders were issued following the FERC Sunshine Open Meeting today, December 20, 2012. Below is a FERC summary of the order on the Integration of Variable Energy Resources, and also attached is a News Release on the Order Approving NERC's Revised Definition of Bulk Electric System.

E-1, *Integration of Variable Energy Resources*, Docket No. RM10-11-001. The order denies requests for rehearing of Order No. 764, including denying rehearing of challenges to: (1) the intra-hour scheduling and forecasting reforms adopted in the final rule; (2) statements addressing a public utility transmission provider's obligation to offer generator regulation service; and (3) the estimated burden on small entities to comply with the final rule. The order affirms the basic determinations in Order No. 764, which includes a requirement to offer intra-hourly transmission scheduling at 15-minute intervals and grants a request to extend the period for compliance filings from September 11, 2013 to November 12, 2013.

Thank you.

Elizabeth Heenan
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Reliability | Accountability

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December 2012
Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its December 20, 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 summaries 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-5, **Press Release**

FERC denies rehearing and affirms Order No. 764, clarifies final rule

E-1, *Integration of Variable Energy Resources*, Docket No. RM10-11-001. The order denies requests for rehearing of Order No. 764, including denying rehearing of challenges to: (1) the intra-hour scheduling and forecasting reforms adopted in the final rule; (2) statements addressing a public utility transmission provider's obligation to offer generator regulation service; and (3) the estimated burden on small entities to comply with the final rule. The order affirms the basic determinations in Order No. 764, which includes a requirement to offer intra-hourly transmission scheduling at 15-minute intervals and grants a request to extend the period for compliance filings from September 11, 2013 to November 12, 2013.

FERC denies rehearing

E-2, *Iberdrola Renewables, Inc., et al. v. Bonneville Power Administration*, Docket No. EL11-44-001. This order denies requests for rehearing of an order issued on December 7, 2011, which granted a petition against Bonneville by a group of wind generators alleging that Bonneville's Environmental Redispatch Policy resulted in non-comparable transmission service for certain resources, including wind generators, connected to Bonneville's transmission system.

FERC conditionally accepts a compliance filing

E-3, *Iberdrola Renewables, Inc., et al. v. Bonneville Power Administration*, Docket No. EL11-44-002. This order conditionally accepts Bonneville's compliance filing submitted in response to the Commission's December 7, 2011 order, which directed that Bonneville file tariff revisions that provide for transmission service on terms and conditions that are comparable to those under which Bonneville provides transmission services to itself, and which are not unduly discriminatory or preferential. The order directs Bonneville to file a further compliance filing that includes a cost allocation methodology that allocates displacement costs in a manner that, in conjunction with the non-rate terms and conditions, ensures comparable service.

FERC approves final rule

E-4, *Availability of E-Tag Information to Commission Staff*, Docket No. RM11-12-000. This final rule amends the Commission's regulations to provide the Commission with access, on a non-public and ongoing basis, to the complete electronic tags (e-Tags) used to schedule the transmission of electric power interchange transactions in wholesale markets. This is accomplished by directing e-Tag Authors (through their Agent Service) and Balancing Authorities (through their Authority Service) to provide for Commission access to the e-Tags covered by this final rule by designating the Commission as an addressee on the e-Tags. In addition, the final rule requires that e-Tag information be made available to regional transmission organizations and independent system operators and their Market Monitoring Units, upon request to e-Tag Authors and Authority Services, subject to appropriate confidentiality restrictions.

FERC conditionally approves, with limited exceptions, revisions to NERC's Rules of Procedure

E-7, *North American Electric Reliability Corporation*, Docket No. RR12-8-000. This order conditionally approves, with limited exceptions, numerous revisions to the NERC Rules of Procedure and its appendices, including revisions to Sections 300 (Reliability Standards Development), 400 (Compliance Enforcement), 600 (Personnel Certification), 800 (Reliability Assessment and Performance Analysis), 1000 (Situation Awareness and Infrastructure Security), 1400 (Amendments to the Rules of Procedure), and 1700 (Challenges to Determinations), and Appendices 2 (Definitions), 3C (Procedure for Coordinating Reliability Standards Approvals, Remands, and Directives), 4B (Sanction Guidelines), 4C (Uniform Compliance Monitoring and Enforcement Program), 5B (Statement of Compliance Registry Criteria), and 6 (System Operator Certification Program Manual). The order directs NERC to make compliance and informational filings within 60 days.

FERC denies rehearing

E-8, *North American Electric Reliability Corporation*, Docket No. NP11-238-001. The order denies rehearing of the Commission's July 2012 order, which approved a $19,500 penalty against the Southwestern Power Administration for violation of certain mandatory Reliability Standards. The order reaffirms the legal finding in the July 2012 order that federal entities that act as users, owners, or operators of the bulk power system are subject to monetary penalties for violation of an approved Reliability Standard, in accordance with the enforcement authorities granted under Federal Power Act section 215.

FERC approves a final rule

E-9, *Regional Reliability Standard PRC-006-SERC-01 —Automatic Underfrequency Load Shedding Requirements*, Docket No. RM12-9-000. This final rule approves regional Reliability Standard PRC-006-SERC-01 (Automatic Underfrequency Load Shedding Requirements), which was submitted for approval by the North American Electric Reliability Corporation (NERC). The final rule finds that PRC-006-SERC-01 is designed to work in conjunction with PRC-006-1 (i.e., the national Underfrequency Load Shedding [UFLS] Reliability Standard) to mitigate effectively the consequences of an underfrequency event while accommodating differences in system transmission and distribution topology among SERC Reliability Corp. (SERC) planning coordinators due to historical design criteria, makeup of load demands, and generation resources. The final rule directs one modification to an associated violation risk factor, which NERC and SERC agreed to make in their comments in response to the Notice of Proposed Rulemaking. The final rule also addresses SERC's commitment to modify the rationale statement for one Requirement to address a possible inconsistency between the regional Reliability Standard and national UFLS Reliability Standard PRC-006-1.

FERC accepts tariff revisions

E-11, *Southwest Power Pool, Inc*., Docket No. ER13-178-000. This order accepts SPP's revisions to Appendix 1 of Attachment M (Loss Compensation Procedure) of its Open Access Transmission Tariff to incorporate an updated transmission line loss factor for Westar Energy Inc. The order accepts the revisions, to be effective September 1, 2012, subject to refund, and the outcome of the hearing and settlement judge proceedings established in Docket No. ER12-909-000.

FERC orders hearing and settlement judge procedures

E-12, *City of Colton, California*, Docket No. ER-13-207-000. The order finds that the City of Colton, California's (Colton) Transmission Owner Tariff (TO Tariff) and Transmission Revenue Requirement (TRR), which have been filed as part of Colton's

becoming a Participating Transmission Owner within the California Independent System Operator Corporation, raise issues of material fact that cannot be resolved based on the record before the Commission and are more appropriately addressed in hearing and settlement judge procedures. The order therefore accepts Colton's TO Tariff and TRR for filing, effective January 1, 2013, and sets all issues for hearing and settlement judge procedures.

FERC conditionally accepts CAISO filing

E-13, *California Independent System Operator Corporation*, Docket No. ER13-168-000. The order conditionally accepts an amended Interconnected Balancing Authority Area Operating Agreement between CAISO and the Western Area Power Administration – Desert Southwest Region, subject to a compliance filing to reflect the transition of Valley Electric Association, Inc. from the Nevada Power balancing authority area to CAISO's balancing authority area.

FERC conditionally accepts CAISO's proposed tariff amendment

E-14, *California Independent System Operator Corporation*, Docket No. ER13-218-000. This order conditionally accepts CAISO's proposed tariff amendment, effective January 1, 2013, to provide a one-time opportunity for certain generators in CAISO's interconnection queue to downsize their projects, in order to facilitate completion and achieve commercial operation of projects that would be viable but for an inability to construct the full megawatt generating capacity originally requested. CAISO is also directed to submit a compliance filing to clarify that the amendments will not affect non-downsizing generators' "hold harmless" protections.

FERC conditionally accepts, in part, and rejects, in part, CAISO tariff revisions

E-15, *California Independent System Operator Corporation*, Docket No. ER13-219-000. The order conditionally accepts, in part, and rejects, in part, tariff revisions submitted by the CAISO which are designed to include greenhouse gas compliance costs in the calculations set forth in the CAISO tariff. The order finds that, in general, CAISO's proposal to incorporate the costs of the greenhouse gas allowances into the calculation of generating units' variable costs is just and reasonable. However, the order finds that CAISO has not demonstrated that its alternative methodology for calculating the greenhouse gas allowance price is just and reasonable. Finally, the Commission finds to be unacceptable CAISO's proposal to list the price indices it will use to calculate the greenhouse allowance price in the Business Practice Manual, rather than in the tariff, and CAISO's proposal to remove from its tariff the natural gas price indices it uses for the default energy bid and state the indices in the Business Practice Manual; the order directs a compliance filing to include such indices in its tariff.

FERC accepts filing, sets issues for hearing and settlement judge procedures

E-16, *Valley Electric Association, Inc.*, Docket No. ER13-49-000. The order accepts a Transmission Owner Tariff and initial Transmission Revenue Requirement filed by Valley Electric, effective January 3, 2013, the date of Valley Electric's planned transition to the CAISO balancing authority. The order sets all issues for hearing and settlement judge procedures.

FERC accepts joint application to transfer certain facilities

E-17, *FirstEnergy Generation Corp.*, Docket No. EC12-119-000. The order accepts the joint application from FirstEnergy Generation Corp. and its affiliate American Transmission System, Inc. under section 203(a)(1) of the Federal Power Act to transfer certain generation facilities for the purpose of converting them into synchronous condensers to provide reactive power to the transmission system.

FERC grants petition for declaratory order

E-22, *Catalina Solar LLC, et al.*, Docket No. EL12-109-000. The order grants a petition for declaratory order filed by a group of affiliated renewable power generation developers, confirming petitioners' priority firm transmission rights to the full capacity of the Antelope Valley Line to be constructed by, and jointly owned by, petitioners. Such rights are subject to petitioners offering service to others to the extent petitioners are not using such capacity, however, and also to an obligation to expand the line if a third-party requests capacity and there is no capacity available.

FERC denies rehearing

G-1, *Northern Natural Gas Company*, Docket Nos. RP11-2061-002 and RP11-2061-003. The order denies rehearing of an order issued December 11, 2011 in which the Commission required Northern to revise its tariff to grant partial reservation charge credits for *force majeure* events. The order reaffirms the Commission's prior holdings that Northern's inclusion of three percent of its fixed costs in its usage charge did not justify exempting it from providing any reservation charge credits during *force majeure* outages and that Northern must file revised reservation charge crediting provisions consistent with the Commission policy concerning the credits to be given during non-*force majeure* outages as well.

In its filing to comply with the December 11 order, Northern proposes to use a hybrid of the Safe Harbor and No Profit method to provide credits during a *force majeure* period with a 15 day safe harbor period, and after full credit for 15 days, use of the No Profit method on all subsequent days. The order rejects that proposal. However, the order permits Northern to add one day to the Safe Harbor 10-day period or choose the No Profit method. The order also requires certain other changes in the revised tariff provisions.

FERC accepts, subject to conditions, revisions to tariff provisions in separate cases

G-2, *Gulf Crossing Pipeline Company LLC*, Docket No. RP12-814-000, and **G-4**, *Gulf South Pipeline, LP*, Docket No. RP12-813-000. The separate orders accept, subject to conditions, Gulf Crossing's and Gulf South's proposals to modify their reservation charge crediting tariff provisions to comply with Commission policy for their respective pipelines. In both dockets, the companies propose to provide partial reservation charge credits to customers during *force majeure* events, through the approved Safe Harbor Method of equitable sharing, and full reservation charge credits during non-*force majeure* events, including maintenance events not included in its revised definition of *force majeure*. The companies also propose to revise their definition of *force majeure* to include outages resulting from the pipelines' compliance with the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (2011 Act) and requirements issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to the 2011 Act and other ongoing gas pipeline rulemaking proceedings.

Both orders find that, with one exception, the nature and timing of any new safety requirements PHMSA may adopt in accordance with the 2011 Act or ongoing PHMSA rulemakings is too speculative at this time to justify modifying Commission policy to treat any outages resulting from such new requirements as *force majeure* events. However, both orders do allow partial reservation charge crediting for a transitional two-year period for outages due to orders PHMSA may issue pursuant to the 2011 Act, requiring specific pipelines to (1) reconfirm their Maximum Allowable Operating Pressure (MAOP) and/or (2) take interim measures to ensure safety until MAOP is reconfirmed. Unlike the other provisions of the 2011 Act, the Act authorizes PHMSA to take these actions without conducting any rulemaking proceeding, and those actions go beyond the routine, periodic maintenance regulatory requirements which the Commission has historically required to be treated as non-*force majeure* events. This determination is without prejudice to the companies' filing a proposal to allow equitable sharing of credits resulting from other new safety requirements PHMSA may adopt, after the nature and timing of such new requirements becomes sufficiently clear to allow consideration of whether such a proposal is just and reasonable. Both orders note that the Commission is aware of and closely monitoring the possible impact of the 2011 Act and PHMSA rulemakings and will consider the need for further action as the impact of PHMSA's implementation process moves forward. Finally, the orders require other revisions of the companies' reservation charge crediting proposals to be consistent with current Commission policy.

FERC accepts, subject to conditions, tariff provisions

G-3, *Texas Gas Transmission, LLC*, Docket No. RP12-820-000. The order accepts, subject to conditions, Texas Gas' proposal to modify its reservation charge crediting tariff provisions to comply with Commission policy. Texas Gas proposes the same

revision to its definition of *force majeure* as proposed by the pipelines in Agenda Items G-2 and G-4.
The order makes identical rulings and requirements as those rendered in Agenda Items G-2 and G-4, finding that, with one exception, the nature and timing of any new safety requirements PHMSA may adopt in accordance with the 2011 Act or ongoing PHMSA rulemakings is too speculative at this time to justify modifying Commission policy to treat any outages resulting from such new requirements as *force majeure* events.
Unlike the Gulf Crossing and Gulf Crossing proposals in Agenda Items G-2 and G-4, Texas Gas' proposal requests that *force majeure* events have a safe harbor period of 20 days, rather than the customary 10-day period. Texas Gas asserts that the fact it includes some fixed costs in its usage charge justifies its use of a longer safe harbor period. The order, using an analysis similar to that used in Agenda Item G-1, *Northern Natural Gas Co.*, rejects Texas Gas' proposal for a 20-day safe harbor, but permits Texas Gas to add one day to the 10-day safe harbor period, or choose the No Profit method. Finally, the order requires other revisions to Texas Gas' reservation charge crediting proposal consistent with current Commission policy.

FERC grants a petition for declaratory order

G-5, *Enbridge Pipelines (Southern Lights) LLC*, Docket No. OR12-27-000. The order grants Enbridge's petition requesting the Commission issue a declaratory order confirming the validity of the contractual right of first offer (ROFO) for committed capacity on Enbridge's Southern Lights oil pipeline as set forth in section 6.06 of the Southern Lights Transportation Service Agreement. Enbridge plans to hold an open season in December 2012 offering additional committed capacity on the existing Southern Lights facilities in accordance with section 6.06. Enbridge needs assurance that it can proceed with the open season because certain potential shippers have questioned the validity of the section 6.06 ROFO in the past.

FERC grants rehearing and reinstates license applications

H-1, *Lock 14 Hydro Partners, LLC, Project No. 13213-004 and Lock 12 Hydro Partners*, Project No. 13214-004. The order grants rehearing of letter orders from the Acting Director, Office of Energy Projects, rejecting as patently deficient the license applications filed by Lock 14 Hydro Partners, LLC for the Heidelberg Project No. 13213 and Lock 12 Hydro Partners, LLC for the Ravenna Project No. 13214, and gives the applicants 90 days to correct omissions in the applications. The Heidelberg Project is located on the Kentucky River in Lee County, Kentucky. The Ravenna Project is located on the Kentucky River in Estill County, Kentucky.

FERC denies rehearing

H-2, *Utah Independent Power, Inc*. Project No. P-14354-001. The order denies a joint request for rehearing filed by Canyonlands Watershed Council, Grand Canyon Trust, and Living Rivers-Colorado Riverkeeper of Commission staff's September 24, 2012 order issuing a preliminary permit to Utah Independent Power, Inc. (Independent Power) to study the feasibility of the Long Canyon Pumped Storage Project No. 14354. The order concludes that the preliminary permit is not precluded by law and that any eventual license application submitted by Independent Power may differ in important aspects from the proposal included in its permit application.

FERC denies rehearing

H-3, *Hudson River-Black River Regulating District et al.,* Docket No. HB81-09-2-001. The order denies Erie Boulevard Hydropower L.P.'s request for rehearing of the Commission staff's July 31, 2012 order determining headwater benefits in the Hudson River Basin. The order notes that Erie Boulevard does not dispute the final charges determined in the July 31 order for the period 2002 to 2008. As for the July 31 order's determination of interim charges for the period 2009 onwards, the order observes that these interim charges were set consistent with Commission precedent and that piecemeal revisions would be inefficient. Moreover, the order notes that the interim charges will be trued up when the next headwater benefits study is conducted.

FERC seeks comments on a Notice of Proposed Rulemaking

C-1, *Revisions to the Auxiliary Installations, Replacement Facilities, and Siting and Maintenance Regulations*, Docket No. RM12-11-000. In response to a request by the Interstate Natural Gas Association of America that the Commission clarify its section 2.55(a) regulations covering the installation of auxiliary facilities, the Commission is proposing to revise its regulations to clarify and specify that all auxiliary facilities must be located within an existing right-of-way and use the same work spaces used for the construction of the existing facilities.

In addition, the Commission notes that property owners with existing gas facilities on their land have contacted Commission staff to complain about companies coming onto their property without any advance notification. In response, the Commission is proposing to impose a landowner notification requirement on companies that install or replace facilities under section 2.55 or undertake any siting or maintenance activities under section 380.15.

FERC grants in part and dismisses in part a complaint

C-2, *Brian Hamilton v. El Paso Natural Gas Company*, Docket No. CP12-25-000. The order grants, in part, and dismisses, in part, a complaint filed by Mr. Brian Hamilton

against El Paso Natural Gas Company. The order finds El Paso performed a line-lowering operation under the authority of its original certificate (rather than under its blanket construction certificate or section 2.55(b) as asserted by Mr. Hamilton) and, as such, had the responsibility under the Commission's regulations to return the property to pre-operation conditions. The order rejects El Paso's procedural arguments based on a previous arbitration proceeding between El Paso and Mr. Hamilton such as res judicata, collateral estoppel, and laches, and other procedural arguments such as the federal statute of limitations at 28 U.S.C. § 2462.

FERC approves, with conditions, new interstate natural gas pipeline and storage facilities

C-3, *Dominion Transmission, Inc.*, Docket No. CP12-72-000. The order authorizes, with conditions, Dominion's proposal to construct and operate compression, pipeline, and storage facilities located in Frederick County, Maryland; Monroe County, Ohio; Lewis County, West Virginia; and Tioga County, Pennsylvania (Allegheny Storage Project). The proposed Allegheny Storage Project will provide an additional 115,000 dekatherms (Dth) per day of firm transportation services, an additional 7.5 billion cubic feet of firm storage capacity and 125,000 Dth per day of additional storage withdrawal service to interstate customers.

From:	Elizabeth Heenan
To:	reg_corresp_notif
Subject:	NERC: FERC Sunshine Open Meeting Agenda for December 20, 2012
Date:	Friday, December 14, 2012 11:10:04 AM
Attachments:	FERC Agenda 122012.pdf

To NERC Management and Regional Entity Executives:

Attached please find the FERC Sunshine Open Meeting agenda for September 20, 2012. There are five items of interest to NERC.

Agenda Item E-1 in Docket No. RM10-11-001 - Integration of Variable Energy Resources. This is a docket in which NERC has commented on the integration of variable energy resources.

Agenda Item E-5 in Docket Nos. RM12-6-000 and RM12-7-000 - Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure. NERC submitted two January 25, 2012 petitions in which it proposed to modify the currently-effective definition of Bulk Electric System and add a process to the NERC Rules of Procedure creating an exception process to classify or de-classify a facility as part of the "bulk electric system." On June 22, 2012, FERC issued a Notice of Proposed Rulemaking in which it proposed to approve this modification. NERC submitted comments on September 4, 2010, and Reply Comments on September 19, 2012.

Agenda Item E-7 in Docket No. RR12-8-000 - North American Electric Reliability Corporation. This is a docket in which a petition to modify to the NERC Rules of Procedure is pending. The filing includes revisions to Sections 300, 400, 600, 1000, 1400 and 1700 and to Appendices 2, 4B, 4C, and 5B, and the deletion of Appendices 3C and 6 to the NERC Rules of Procedure. The proposed revisions are the result of a wide-ranging, comprehensive review of the ROP that was conducted to identify improvements to the underlying processes reflected in the ROP based on the experience to date of NERC and the Regional Entities, to further implement actions identified in 2009 in NERC's Three-Year ERO Performance Assessment Report, to eliminate internal inconsistencies, and to make other improvements and clarifications identified by the review teams.

Agenda Item E-8 in Docket No. NP11-238-001 - North American Electric Reliability Corporation. This is a docket in which a Notice of Penalty regarding Southwestern Power Administration is pending.

Agenda Item E-9 in Docket No. RM12-9-000 - Regional Reliability Standard PRC-006-SERC-01-Automatic Underfrequency Load Shedding Requirements. This is a docket in which NERC submitted a petition for approval of PRC-006-SERC-01. FERC issued a NOPR on July 19, 2012, and NERC submitted a filing in support of the SERC Reliability Corporation response to the NOPR on September 24, 2012.

Thank you,

Elizabeth Heenan
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Y

From:	Elizabeth Heenan
To:	reg_corresp_notif
Subject:	NERC: Order Approving PRC-006-SERC-01 and Sunshine Open Meeting Summary
Date:	Thursday, December 20, 2012 11:23:40 AM
Attachments:	Final_Rule_PRC-006-SERC-1.pdf

To NERC Management and Regional Entity Executives:

Attached please find a Final Rule approving Regional Reliability Standard PRC-006-SERC-01 – Automatic Underfrequency Load Shedding Requirements, issued today following the Sunshine Open meeting in Docket No. RM12-9-000. Below, please find the FERC summary issued with the order.

ERC approves a final rule

E-9, *Regional Reliability Standard PRC-006-SERC-01 —Automatic Underfrequency Load Shedding Requirements*, Docket No. RM12-9-000. This final rule approves regional Reliability Standard PRC-006-SERC-01 (Automatic Underfrequency Load Shedding Requirements), which was submitted for approval by the North American Electric Reliability Corporation (NERC). The final rule finds that PRC-006-SERC-01 is designed to work in conjunction with PRC-006-1 (i.e., the national Underfrequency Load Shedding [UFLS] Reliability Standard) to mitigate effectively the consequences of an underfrequency event while accommodating differences in system transmission and distribution topology among SERC Reliability Corp. (SERC) planning coordinators due to historical design criteria, makeup of load demands, and generation resources. The final rule directs one modification to an associated violation risk factor, which NERC and SERC agreed to make in their comments in response to the Notice of Proposed Rulemaking. The final rule also addresses SERC's commitment to modify the rationale statement for one Requirement to address a possible inconsistency between the regional Reliability Standard and national UFLS Reliability Standard PRC-006-1.

Thank you.

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From:	Elizabeth Heenan
To:	reg_corresp_notif
Subject:	NERC: Order Conditionally Approving Changes to the NERC Rules of Procedure
Date:	Thursday, December 20, 2012 11:49:18 AM
Attachments:	Order_Cond_NERCRoP_2012.12.pdf

To NERC Management and Regional Entity Executives:

Attached please find an order conditionally approving revisions to the NERC Rules of Procedure, issued today following the Sunshine Open meeting in Docket No. RM12-8-000. Below, please find the FERC summary issued with the order.

FERC conditionally approves, with limited exceptions, revisions to NERC's Rules of Procedure

E-7, *North American Electric Reliability Corporation*, Docket No. RR12-8-000. This order conditionally approves, with limited exceptions, numerous revisions to the NERC Rules of Procedure and its appendices, including revisions to Sections 300 (Reliability Standards Development), 400 (Compliance Enforcement), 600 (Personnel Certification), 800 (Reliability Assessment and Performance Analysis), 1000 (Situation Awareness and Infrastructure Security), 1400 (Amendments to the Rules of Procedure), and 1700 (Challenges to Determinations), and Appendices 2 (Definitions), 3C (Procedure for Coordinating Reliability Standards Approvals, Remands, and Directives), 4B (Sanction Guidelines), 4C (Uniform Compliance Monitoring and Enforcement Program), 5B (Statement of Compliance Registry Criteria), and 6 (System Operator Certification Program Manual). The order directs NERC to make compliance and informational filings within 60 days.

Thank you.

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Y

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

NOTICE OF CHANGE IN MEETING

(December 18, 2012)

Upon the affirmative vote of Chairman Wellinghoff and Commissioners Moeller, Norris, LaFleur, and Clark, the following Docket Nos. and subject name are hereby added as Item Nos. A-3 and A-4 on the Commission's open meeting scheduled for December 20, 2012.

ITEM NO.	DOCKET NO. AND SUBJECT
A-3	AD13-2-000, 2012 Assessment of Demand Response and Advanced Metering
A-4	AD13- 3-000, California Cap and Trade Overview

Kimberly D. Bose,
Secretary.

From:	John G. Mosier Jr.
To:	cc-npcc; tfco-all; co11; john_allen@rge.com; "matkins@velco.com"; dbertagnolli@iso-ne.com; rwburke@iso-ne.com; gcampoli@nyiso.com; "John.W.Conlon@nstar.com"; dhaas@velco.com; nabil.hitti@nationalgrid.com; michael.jones@nationalgrid.com; Marie Kozub; Jennifer Budd Mattiello; "elizabeth.pagliarini@nu.com"; Paul A. Roman; Ed Schwerdt; "templwj@nu.com"; yostp@coned.com
Cc:	grpStaff
Subject:	Data Request to Fulfill FERC Order No. 693-2012 Quarter 4
Date:	Friday, December 28, 2012 11:01:54 AM
Attachments:	NERC_Blank-Nuclear_Data_Reporting_Order_693-2012Q4.xls 20121228_JGM-Registered_Transmission_Entities_FERC_693_2012Q4.doc

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

December 28, 2012

NPCC Registered Transmission Entities

Consolidated Edison Company of New York, Inc.
Mr. Peter Yost
Entergy East-RG&E
Mr. John Allen
ISO New England Inc.
Mr. Richard Burke
New York ISO
Mr. Greg Campoli
Niagara Mohawk Power Corporation
Mr. Michael Jones
Northeast Utilities Services Company
Ms. Elizabeth A. Pagliarini
NSTAR Electric
Mr. John W. Conlon
Public Service Company of New Hampshire
Mr. William Temple
Vermont Transco, LLC
Mr. Mark Atkins
Mr. David Haas

Re: Official Data Request to Fulfill FERC Order No. 693 Requirements-Restoration of Nuclear Power Plant Offsite Power Sources
Request for Data for the Fourth Quarter of 2012 (October 1-December

31, 2012)

Sir / Madam:

Attached is the request for the data associated with the NERC and Federal Energy Regulatory Commission (FERC) directive 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. This data request is directed to United States entities only through Order No. 693 issued by the FERC. Canadian entities are not obligated to respond.

The data required constitutes an ongoing request first initiated in the fourth quarter of calendar year 2007. The data will continue to be collected on a quarterly basis and submitted to NERC by the Regional Reliability Organizations thirty days after the end of each reporting quarter. I am now requesting your submissions for the fourth quarter of 2012 (October 1-December 31, 2012).

For your information, a reiteration of the nature of the information requested follows. 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 provided in the attached spreadsheet provided by the 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 NERC Standard EOP-005-1, “System Restoration Plans.”)
- Discussion of scenario assumptions or constraints impacting the restoration of the initial offsite power source to the nuclear power plant

If an exercise, drill or simulation was not conducted during the reporting quarter, a report is not required. The data is to be channeled through the

Regional Reliability Organization (NPCC) and then to Ms. Monica Benson of the NERC. For your assistance, you will find attached the blank form developed by the NERC for the submission of your data.

To fulfill the NERC deadline, please return your submissions to Mr. Paul Roman of NPCC (proman@npcc.org) and myself (jmosier@npcc.org) by Friday, January 25, 2013.

Thank you for your assistance in this effort.

Very truly yours,

J. G. Mosier, Jr.

John G. Mosier, Jr.
Assistant Vice President-
System Operations

JGM:mr

cc: Members, NPCC Compliance Committee
Members, NPCC Task Force on Coordination of Operation
Members, NPCC Restoration Working Group (CO-11)
Mr. David Bertagnolli
Mr. Nabil E. Hitti
Ms. Marie Kozub
Ms. Jennifer B. Mattiello
Mr. Paul Roman
Mr. Edward A. Schwerdt
Mr. William Temple

Email:

cc-npcc@npcc.org ; tfco-all@npcc.org; co11@npcc.org; John_Allen@rge.com; matkins@velco.com; dbertagnolli@iso-ne.com; rwburke@iso-ne.com; gcampoli@nyiso.com; John.W.Conlon@nstar.com; dhaas@velco.com; nabil.hitti@us.ngrid.com; michael.jones@us.ngrid.com; mkozub@npcc.org; jbudd@npcc.org; elizabeth.pagliarini@nu.com; proman@npcc.org; eschwerdt@npcc.org; templwj@nu.com; yostp@coned.com

Restoration of Nuclear Power Plant Offsite Power Source Data Request Reporting Spreadsheet

Reporting Transmission Operator:
Reporting Period: **4th Quarter 2012: October 1-December 31, 2012**

Transmission Operator	Date of Exercise, Drill, or Simulation	Name of Exercise, Drill, or Simulation	Name of Nuclear Plant	Unit Designation	Identifier of Offsite Power Source	Duration Loss of Offsite Power Source to Restoration of Source	Discussion of Scenario Assumptions Impacting Restoration of the Offsite Power Sources

Restoration of Nuclear Power Plant Offsite Power Source Data Request Reporting Spreadsheet

Reporting Transmission Operator:
Reporting Period: **4th Quarter 2012: October 1-December 31, 2012**

Transmission Operator	Date of Exercise, Drill, or Simulation	Name of Exercise, Drill, or Simulation	Name of Nuclear Plant	Unit Designation	Identifier of Offsite Power Source	Duration Loss of Offsite Power Source to Restoration of Source	Discussion of Scenario Assumptions Impacting Restoration of the Offsite Power Sources

Restoration of Nuclear Power Plant Offsite Power Source Data Request Reporting Spreadsheet

Reporting Transmission Operator:
Reporting Period: **4th Quarter 2012: October 1-December 31, 2012**

Transmission Operator	Date of Exercise, Drill, or Simulation	Name of Exercise, Drill, or Simulation	Name of Nuclear Plant	Unit Designation	Identifier of Offsite Power Source	Duration Loss of Offsite Power Source to Restoration of Source	Discussion of Scenario Assumptions Impacting Restoration of the Offsite Power Sources

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Reporting Period: **4th Quarter 2012: October 1-December 31, 2012**

Transmission Operator	Date of Exercise, Drill, or Simulation	Name of Exercise, Drill, or Simulation	Name of Nuclear Plant	Unit Designation	Identifier of Offsite Power Source	Duration Loss of Offsite Power Source to Restoration of Source	Discussion of Scenario Assumptions Impacting Restoration of the Offsite Power Sources

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Reporting Transmission Operator:
Reporting Period: **4th Quarter 2012: October 1-December 31, 2012**

Transmission Operator	Date of Exercise, Drill, or Simulation	Name of Exercise, Drill, or Simulation	Name of Nuclear Plant	Unit Designation	Identifier of Offsite Power Source	Duration Loss of Offsite Power Source to Restoration of Source	Discussion of Scenario Assumptions Impacting Restoration of the Offsite Power Sources

Restoration of Nuclear Power Plant Offsite Power Source Data Request Reporting Spreadsheet

Reporting Transmission Operator:
Reporting Period: **4th Quarter 2012: October 1-December 31, 2012**

Transmission Operator	Date of Exercise, Drill, or Simulation	Name of Exercise, Drill, or Simulation	Name of Nuclear Plant	Unit Designation	Identifier of Offsite Power Source	Duration Loss of Offsite Power Source to Restoration of Source	Discussion of Scenario Assumptions Impacting Restoration of the Offsite Power Sources

Restoration of Nuclear Power Plant Offsite Power Source Data Request Reporting Spreadsheet

Reporting Transmission Operator:
Reporting Period: **4th Quarter 2012: October 1-December 31, 2012**

Transmission Operator	Date of Exercise, Drill, or Simulation	Name of Exercise, Drill, or Simulation	Name of Nuclear Plant	Unit Designation	Identifier of Offsite Power Source	Duration Loss of Offsite Power Source to Restoration of Source	Discussion of Scenario Assumptions Impacting Restoration of the Offsite Power Sources

Restoration of Nuclear Power Plant Offsite Power Source Data Request Reporting Spreadsheet

Reporting Transmission Operator:
Reporting Period: **4th Quarter 2012: October 1-December 31, 2012**

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January 2013
Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its January 17, 2013 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 summaries 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

H-1, Press Release

FERC announces a policy statement

E-2, *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects; Priority Rights to New Participant Funded Transmission*, Final Policy Statement, Docket Nos. AD12-9-000, AD11-11-000. This final policy statement clarifies and refines current policies governing the allocation of capacity for new merchant transmission projects and new non-incumbent, cost-based, participant-funded transmission projects. The final policy statement allows developers of such transmission projects to select a subset of customers based on not unduly discriminatory criteria and negotiate directly with those customers to reach agreement on the key terms and conditions for procuring transmission capacity, so long as they (1) broadly solicit interest in the project from potential customers, and (2) demonstrate to the Commission that the developer has satisfied the solicitation, selection and negotiation process criteria set forth in the final policy statement.

FERC grants petition for declaratory order

E-3, *NextEra Energy Resources, LLC; Peetz Logan Interconnect, LLC; PWEC, LLC*, Docket No. EL11-46-000. The order grants Petitioners' request for PWEC to have priority rights to capacity over the Peetz Logan generator interconnection facility for a third phase of the Petitioners' planned wind project development (PWEC Project), because Petitioners have demonstrated that the forthcoming PWEC Project is covered by a pre-existing expansion plan, with milestones for the planning, design and construction of generation and material progress toward meeting those milestones. The order also states that the Commission will no longer require transfer of ownership of generator

interconnection facilities to their affiliates as a condition for granting priority rights to generation-developing affiliates of a transmission owner.

FERC conditionally accepts compliance filings, subject to modifications

E-5, *Peetz Logan Interconnect, LLC*, Docket Nos. ER11-2970-001 and ER11-2970-002. The order conditionally accepts two compliance filings submitted in accordance with the Commission's August 2, 2011 order (August 2011 Order), which conditionally accepted in part, and rejected in part, Peetz Logan's open access transmission tariff (OATT). This order finds that Peetz Logan's subsequent compliance filings satisfy some, but not all, of the directives in the August 2011 Order. Thus, in this order, the Commission conditionally accepts the two compliance filings, subject to modifications that will bring Peetz Logan's OATT into compliance with the directives of the August 2011 Order.

FERC denies complaint

E-6, *Rail Splitter Wind Farm, LLC v. Ameren Services Company and Midwest Independent Transmission System Operator, Inc.*, Docket No. EL12-11-000. This order denies the complaint of Rail Splitter Wind Farm, LLC (Rail Splitter) against Ameren Services Company (Ameren) and Midwest Independent Transmission System Operator, Inc. Specifically, the order finds that the *Mobile-Sierra* public interest standard of review does not apply to the FSA and that Rail Splitter failed to demonstrate that an agreement between Rail Splitter and Ameren should be modified under the ordinary just and reasonable standard of review; accordingly, Rail Splitter remains obligated to make monthly payments to pay for the cost of network upgrades.

FERC affirms previous order, accepts compliance filing

E-8, *E.ON Climate & Renewables North America, LLC v. Midwest Independent Transmission System Operator, Inc*., Docket Nos. EL11-30-001 and ER12-451-000. The order affirms the Commission's October 20, 2011 order, which was issued in response to a complaint filed by the Midwest Generation Development Group, and which directed Midwest Independent Transmission System Operator, Inc. (MISO) to remove from its tariff one of two options for transmission owners to collect from interconnection customers the costs associated with network upgrades. The order affirms that allowing transmission owners the choice between Option 1 and Option 2 in MISO's tariff creates an opportunity for undue discrimination to the extent that it allows the transmission owner discretion to increase the costs associated with particular generators, and accepts MISO's filing to delete Option 1 from its tariff. The order also finds that the Initial Order did not automatically modify any existing agreement, and clarifies that the Commission will not apply the findings of the Initial Order to agreements effective prior to March 22, 2011. The order also reiterates that, to the extent that MISO believes that elimination of Option 1 raises concerns about the impact of certain costs on particular transmission

owners and their customers, MISO may file a proposal under section 205 of the Federal Power Act to address such concerns.

FERC grants a petition for declaratory order

E-10, *Blue Summit Wind, LLC*, Docket No. EL13-17-000. This order disclaims Commission jurisdiction over a proposed interconnection that will deliver electric energy from Blue Summit's wind generation facility, located in the Southwest Power Pool region of Texas, to an interconnection point in the Electric Reliability Council of Texas (ERCOT) region, and also over sales and transmission of energy over the interconnection. The order also declares that the electric utilities in ERCOT that are not currently subject to the Commission's jurisdiction as "public utilities" under the Federal Power Act will not become "public utilities" as a result of the interconnection with Blue Summit.

FERC grants a petition for declaratory order

E-11, *Electric Transmission Texas, LLC*, Docket No. EL13-18-000. This order disclaims Commission jurisdiction over proposed transmission projects in the Electric Reliability Council of Texas (ERCOT) region of Texas, as well as over sales and transmission of electric energy over the proposed projects. The order finds that no electric energy will flow in interstate commerce over the projects. The order also declares that the electric utilities in ERCOT that are not currently subject to the Commission's jurisdiction as "public utilities" under the Federal Power Act will not become "public utilities" as a result of the interconnection with the proposed transmission lines.

FERC denies a petition for declaratory order and a complaint

E-12, *Hess Corporation v. PJM Interconnection, LLC*, Docket No. EL12-7-000. This order denies Hess Corporation's (Hess) petition for declaratory order, or in the alternative, complaint against PJM Interconnection, LLC (PJM). Hess requested that the Commission determine that PJM's Open Access Transmission Tariff allowed PJM to make a minor adjustment to two phase angle regulators (PARs) that are owned by Public Service Electric and Gas Company but that are under the operational control of PJM, in order to reduce interconnection upgrade costs associated with the interconnection of the Newark Energy Center. The order denies the requested determinations, finding that PJM's not adjusting the PARs was consistent with its tariff and that PJM did not unduly discriminate against Hess, or other new generation, by refusing to adjust PARs during the interconnection study phase.

FERC sets complaint for hearing

E-13, *North American Natural Resources, Inc. v. PJM Interconnection, LLC; American Electric Power Service Corp; and Indiana Michigan Power Co.*, Docket No. EL13-10-000. The order sets for hearing and settlement judge procedures a complaint filed by North American Natural Resources, Inc. against American Electric Power Service Corporation; its affiliate, Indiana Michigan Power Company; and PJM Interconnection, LLC (PJM). The complainant alleges violations of PJM's Open Access Transmission Tariff provisions governing small generator interconnections to the transmission system.

FERC establishes technical conference

G-1, *Tennessee Gas Pipeline Company, LLC*, Docket No. RP12-514-000. The order establishes a technical conference to discuss operational and technical issues related to Tennessee's proposal to establish a new scheduling priority methodology for secondary in-path transactions. Tennessee's proposed methodology would provide a higher scheduling priority for secondary in-path transactions to primary delivery points over secondary in-path transactions from primary receipt points.

FERC grants rehearing and amends an exemption

H-2, *Calleguas Municipal Water District*, Project No. 14404-001. The order grants Calleguas Municipal Water District's request for rehearing of Commission staff's September 25, 2012 order granting it an exemption from the licensing requirements of Part I of the Federal Power Act for the Grandsen Hydroelectric Generating Station Project No. 14404. The project will be located in the City of Moorpark, in Ventura County, California. The order modifies ordering paragraph (D) of the September 25, 2012 order consistent with the alternative condition the exemptee developed with the U.S. Fish and Wildlife Service and submitted with its rehearing request.

FERC dismisses request for liquefied natural gas import authorization

C-2, *The Gas Company, LLC*, Docket No. CP12-498-000. The order dismisses The Gas Company, LLC's request for authorization to operate facilities to receive and vaporize domestic liquefied natural gas (LNG) transported from the U.S. mainland, for distribution to end use customers in Hawaii. The order finds that the proposed project does not constitute an LNG terminal as envisioned under section 3 of the Natural Gas Act and does not require any other authorization from the Commission.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

November 29, 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
Order No. 693, P 629 Compliance Filing – Third Quarter 2012

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 Order No. 693.[1] Paragraph 629 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. The documents being submitted with this filing include this transmittal letter and a public version of the compliance filing in accordance with NERC's designation of the data contained in **Exhibit B** as Critical Energy Infrastructure Information (CEII) under the Commission's rules. 18 C.F.R. §§ 388.112 & 388.113 (2012).

Exhibit B of the filing includes data that meets the requirements for treatment as CEII as defined in the Commission's Rules and Regulations at 18 C.F.R. § 388.113 (2012). The data in **Exhibit B** pertains to proprietary or business design information, including design information related to vulnerabilities of critical energy infrastructure information that is not publicly available. In accordance with the Commission's Rules and Regulations, 18 C.F.R. § 388.112, a non-public version of the information redacted from the filing is being provided separately. Accordingly, the information set forth in **Exhibit B** has been redacted from this public version of the compliance filing.

[1] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242, P 629 (Order No. 693), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ William H. Edwards
William H. Edwards
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**

THIRD 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,[2] 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 reports information collected for the third quarter of 2012.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[3]

[2] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (Order No. 693), *Order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

[3] 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.

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
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Suite 600, North Tower
Atlanta, GA 30326
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(404) 446-2595– facsimile

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Corporate Secretary
Holly A. Hawkins*****
Assistant General Counsel
William H. Edwards *****
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III. SUMMARY OF RESTORATION DATA OF NUCLEAR POWER PLANT OFF-SITE POWER SOURCES

A. Background

In response to comments offered by the U.S. Nuclear Regulatory Commission during the Notice of Proposed Rulemaking process, the Commission expressed concern, in Order No. 693, regarding the role and priority that nuclear power plants should have in Bulk-Power System restoration plans. The Commission addressed its concern in the discussion of the EOP-005-1 — System Restoration Plans Reliability Standard. Specifically, in Paragraph 629 of Order No. 693, the Commission 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 systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.

In accordance with 18 C.F.R. § 39.2(d), NERC is required to provide information as necessary to the Commission in order to implement section 215 of the Federal Power Act.[4] That same regulation obligates users, owners and operators of the Bulk-Power System to provide NERC with information in support of this same objective. 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 Board of Trustees approval, NERC began to collect nuclear data from U.S. Transmission Operators during the fourth quarter of 2007 and has continued to collect and report the data to the Commission on a quarterly basis. This filing presents data captured for the third quarter of 2012.

The specific data requested of the Transmission Operators includes the following information:

- Identification of the reporting entity;
- Name of the exercise, drill or simulation;
- Date of the exercise, drill or simulation;
- Name of the nuclear plant;
- Unit designation (each unit must be included separately);
- Identification of the off-site power source;
- Time duration measured from the time off-site power sources are lost to the time of restoration of the first off-site power source;[5] and
- Discussion of scenario assumptions or constraints impacting the restoration of the first off-site power source to the nuclear power plant.

The following clarifying language was included in the data request to guide the Transmission Operators when supplying the requested data:

[4] 16 U.S.C. 824o (2006).
[5] For this request, the loss of off-site power sources is the simulated physical interruption of power in support of EOP-005-1 requirements.

> 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.

Exhibit B presents the raw data collected through this period of observation. **Exhibit B** has been redacted from the public version of this report to remove the actual raw data collected through the period of observation that qualifies as CEII. 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 obligations as defined in Reliability Standard EOP-005-1 relative to the priority of restoring off-site power sources to nuclear power plants in system restoration plans.

B. Summary of Data

There are one hundred and four nuclear units in the United States. As of this report, all units have reported data as requested. Transmission Operators conduct 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 the third quarter of 2012, Transmission Operators conducted thirteen individual exercises, drills, or simulations that included the restoration of off-site power sources to a total of fifteen units, with many exercises, drills, or simulations impacting multiple

nuclear units. For example, one entity conducted a system restoration exercise on June 10, 2011 that involved the restoration of off-site power sources to two nuclear units. In the summary chart that follows below, each off-site power source restoration "event" is reported separately for purposes of data analysis.

In total, fifty-three off-site power source restoration "events" are included in the raw data presented in **Exhibit B** of this filing. Of the fifty-three events, there were thirty-eight[6] potential first off-site power source restoration events (some units have multiple off-site sources). The remaining fifteen events included in the data involved the restoration of a subsequent off-site power source beyond the first off-site power source restored. Of the simulated units, one subsequent off-site power source was restored within two hours, three within two to four hours, two within four to six hours, and two within eight to ten hours. Of the remaining seven subsequent off-site power sources, four were restored in more than ten hours and three did not have a time reported for restoration.

NERC categorized the restoration of first off-site power sources in two-hour timeframes. Thirty-four percent (13 of 38) of the first off-site power source restorations occurred within the first two hours following the simulated blackout event, with forty-two percent of restorations (16 of 38) occurring in four hours or less. Three simulated off-site power source restorations were restored within two to four hours, four within eight to ten hours, and sixteen in more than ten hours. Two off-site power sources did not have a restoration time reported.

[6] Not all units provided data for off-site sources beyond the first off-site 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 first source for the rest of the units.

Total Number Offsite Power Source Restoration Events Included in EOP-005-1 Exercises, Drills or Simulations	53
Potential first off-site source restorations	38
Exercises, Drills, or Simulations in which the first off-site source was restored in 2 hours or less following the loss of power	13
Exercises, Drills, or Simulations in which the first off-site source was restored 2-4 hours following the loss of power	3
Exercises, Drills, or Simulations in which the first off-site source was restored 4-6 hours following the loss of power	0
Exercises, Drills or Simulations in which the first off-site source was restored 6-8 hours following the loss of power	0
Exercises, Drills, or Simulations in which the first off-site source was restored 8-10 hours following the loss of power	4
Exercises, Drills or Simulations in which the first off-site source was restored more than 10 hours following the loss of power	16
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	2

IV. CONCLUSION

NERC respectfully requests that the Commission accept this informational filing for the third quarter of 2012 in accordance with Paragraph 629 of Order No. 693.

Respectfully submitted,

/s/ William H. Edwards
William H. Edwards
Attorney for North American Electric Reliability Corporation

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 29th day of November, 2012.

/s/ William H. Edwards
William H. Edwards
Attorney for North American Electric Reliability Corporation

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.

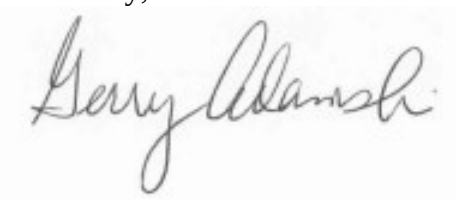
Within the United States, failure to comply with an official data request would constitute a violation of FERC regulations. Enforcement action is available to FERC to deal with violations of its regulations. This is authority FERC could exercise, not authority available to NERC. NERC's Compliance Monitoring 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: 3rd Quarter 2012

CRITICAL ENERGY INFRASTRUCTURE INFORMATION REDACTED

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Coordination between Natural Gas and Electricity Markets — Docket No. AD12-12-000

NOTICE OF REQUEST FOR COMMENTS AND TECHNICAL CONFERENCE

(December 7, 2012)

Take notice that the Federal Energy Regulatory Commission (Commission) staff will hold a technical conference to elicit input pertaining to information sharing and communications issues between natural gas and electric power industry entities. The technical conference will take place on February 13, 2013 beginning at 9:00am and ending at approximately 4:00pm. The conference will be held at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. All interested persons are invited to participate at the conference. Commission members may participate in the conference.

On November 15, 2012, the Commission issued an order directing further conferences and reports in the above captioned docket.[1] In the November 15 Order, the Commission directed staff to establish a technical conference to identify areas in which additional Commission guidance or regulatory changes could be considered. In advance of this conference, interested parties are asked to file comments on the following questions related to communications and information sharing:

1. During an emergency, what kind of verbal communications and data exchanges do and should take place between the natural gas and electric industries? What are the industries' current "best practices" for these communications? How can today's best practices be improved? What should the Commission do, if anything, to facilitate the application of best practices between the industries?

2. Please provide specific examples of other communications practices

[1] *Coordination between Natural Gas and Electricity Markets*, 141 FERC ¶ 61,125, at P 5 (2012) (November 15 Order).

between the natural gas and electric industries that could be enhanced, including any communications regarding maintenance and construction planning, day-to-day operations, and other non-emergency situations. In providing examples, please explain whether there are regulatory or other barriers that would prevent good communications such as specific Commission regulations, tariffs or contractual provisions, legal precedents, or inadequate communications infrastructure.

3. Should natural gas pipeline and electric utility system operators be allowed to exchange information that is not publicly posted? If so, what kinds of information should be permitted to be shared and under what circumstances? If information is shared, is there a need for enhanced protections against the improper use of the material communicated and what protections would be appropriate? Is the answer the same if a natural gas pipeline or its affiliate sells or buys wholesale electric power? If there are concerns that the increased communications might cause potential harm to industry participants, please explain those concerns. Please consider examples of information sharing that include both verbal and digital information.

Responses to these questions will form the basis of the agenda for and discussion at the February 2013 technical conference on communications and information-sharing. Comments responding to this notice should be submitted, in Docket No. AD12-12-000, on or before January 7, 2013. Comments may be filed electronically via the Internet. See the instructions on the Commission's website http://www.ferc.gov/docs-filing/efiling.asp. For assistance, please contact FERC Online Support at FERCOnlineSupport@ferc.gov or toll free at 1-866-208-3676, or for TTY, (202) 502-8659. Although the Commission strongly encourages electronic filing, documents may also be paper-filed. To paper-file, mail an original and seven copies to: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

A supplemental notice will be issued prior to the technical conference with information about the agenda and organization of the technical conference. Those interested in attending the technical conference are encouraged, but not required, to register by close of business February 10, 2013. You may register at the following webpage: https://www.ferc.gov/whats-new/registration/gas-elec-mkts-02-13-13-form.asp. Those also interested in speaking at the technical conference should notify the Commission by January 7, 2013 by completing the online form at the following webpage: https://www.ferc.gov/whats-new/registration/gas-elec-mkts-speaker-02-13-13-form.asp. Due to time constraints, we may not be able to accommodate all those interested in speaking.

The technical conference will not be transcribed. However, there will be a free webcast of the conference. The webcast will allow persons to listen to the technical conference, but not participate.

Anyone with Internet access who wants to listen to the conference can do so by navigating to www.ferc.gov's Calendar of Events and locating the technical conference in the Calendar. The technical conference will contain a link to its webcast. The Capitol Connection provides technical support for the webcast and offers the option of listening to the meeting via phone-bridge for a fee. If you have any questions, visit www.CapitolConnection.org or call 703-993-3100.[2]

Notice is also hereby given that the discussions at the conference may address matters at issue in the following Commission proceeding(s) that are either pending or within their rehearing period: ISO New England Inc., Docket No. ER13-356-000.

Information on the technical conference will also be posted on the website http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp, as well as the Calendar of Events on the Commission's web site, http://www.ferc.gov, prior to the conference.

Commission conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to accessibility@ferc.gov or call toll free (866) 208-3372 (voice) or (202) 208-1659 (TTY), or send a FAX to (202) 208-2106 with the required accommodations.

For more information about the technical conference, please contact:

Caroline Daly (Technical Information)
Office of Energy Policy and Innovation
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426
(202) 502-8931
Caroline.Daly@ferc.gov

Anna Fernandez (Legal Information)
Office of General Counsel
Federal Energy Regulatory Commission

[2] The webcast will continue to be available on the Calendar of Events on the Commission's website www.ferc.gov for three months after the conference.

888 First Street, N.E.
Washington, DC 20426
(202) 502-6682
Anna.Fernandez@ferc.gov

Sarah McKinley (Logistical Information)
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Federal Energy Regulatory Commission
888 First Street, N.E.
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(202) 502-8004
Sarah.McKinley@ferc.gov

Kimberly D. Bose,
Secretary.

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141 FERC ¶ 61,232
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Integration of Variable Energy Resources Docket No. RM10-11-001

ORDER NO. 764-A

ORDER ON REHEARING AND CLARIFICATION AND GRANTING MOTION FOR EXTENSION OF TIME

(Issued December 20, 2012)

1. On June 22, 2012, the Commission issued the *Integration of Variable Energy Resources* Final Rule, requiring each public utility transmission provider to: (1) offer intra-hourly transmission scheduling at 15-minute intervals; and, (2) incorporate provisions into the *pro forma* Large Generator Interconnection Agreement (LGIA) requiring interconnection customers whose generating facilities are variable energy resources (VER) to provide meteorological and forced outage data to the public utility transmission provider for the purpose of power production forecasting.[1] The Commission also provided guidance regarding the development and evaluation of proposals related to recovering the costs of regulation reserves associated with VER integration. Order No. 764 defined a VER as a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by

[1] *Integration of Variable Energy Resources*, Order No. 764, 77 FR 41482 (July 13, 2012) FERC Stats. & Regs. ¶ 31,331 (2012) (Order No. 764). Order No. 764 resulted from the *Integration of Variable Energy Resources,* Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,664 (2010) (Proposed Rule) and the *Integration of Variable Energy Resources,* Notice of Inquiry, FERC Stats. & Regs. ¶ 35,563 (2010) (Notice of Inquiry).

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the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.[2]

2. Requests for rehearing and clarification were submitted regarding certain aspects of: (1) the intra-hour scheduling and forecasting reforms adopted in Order No. 764; (2) statements addressing public utility transmission provider's obligation to offer generator regulation service; and (3) the estimated burden on small entities to comply with the Final Rule. Additionally, Edison Electric Institute (EEI) filed a motion to extend the period for compliance filings from September 11, 2013, to November 12, 2013. In this order, the Commission affirms its basic determinations in Order No. 764, provides clarification, and grants EEI's request to extend the period for compliance filings.

I. Background

3. In Order No. 764, the Commission adopted reforms designed to remove barriers to the integration of VERs and to 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.[3] Noting the increasing number of VERs being brought online, the Commission concluded that reforms were needed to ensure that transmission customers are not exposed to excessive or unduly discriminatory charges, and that public utility transmission providers have the information needed to efficiently manage reserve-related costs.

4. Specifically, the Commission amended 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.[4] The Commission found transmission customers' inability to adjust their transmission schedules within the hour to reflect changes in generation output can cause charges for Schedule 9 generator imbalance service to be unjust and unreasonable or unduly discriminatory. The intra-hour scheduling amendment was designed to correct this deficiency. It was also designed to allow public utility transmission providers, over time, to use fewer reserves to maintain overall system balance.[5]

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[2] Order No. 764, 1FERC Stats. & Regs. ¶ 31,331 at P 1.

[3] *Id.* P 1.

[4] *Id.* P 2.

[5] *Id.* P 95.

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5. The Commission also amended the *pro forma* 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.[6] Such data would only be required where it is necessary for that public utility transmission provider to develop and deploy power production forecasting. This reform was designed to facilitate public utility transmission providers' use of power production forecasts, which the Commission found 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 more costly reserve service, such as regulation reserves.

6. Finally, the Commission declined to modify the *pro forma* OATT to include a new Schedule 10 governing generator regulation service.[7] The Commission explained that the Schedule 10 proposal was intended 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 light of the numerous comments stressing the importance of flexibility in the design of capacity services needed to efficiently integrate VERs into the transmission system, the Commission decided to maintain its existing case-by-case approach to evaluating proposals related to recovering the costs of regulation reserves associated with VER integration. However, the Commission provided guidance in response to the comments submitted to assist public utility transmission providers and their customers in the development and evaluation of such proposals.

II. Motion for Extension of Compliance Period

7. On October 19, 2012, EEI filed a motion to extend the compliance deadline from September 11, 2013, to November 12, 2013.[8] EEI expresses concern that the existing compliance deadline of September 11, 2013, would require public utility transmission providers to implement the modifications associated with Order No. 764's intra-hour scheduling reform during the summer peak season. EEI states that such modifications to industry practices may result in unforeseen issues, which could be exacerbated during

[6] *Id.* P 3.

[7] *Id.* P 4.

[8] EEI notes that American Public Power Association (APPA) and National Rural Electric Cooperative Association (NRECA) have authorized EEI to state that they do not oppose the motion.

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strained situations, such as summer peak conditions. Therefore, EEI requests that the Commission extend the deadline for compliance by 62 days in order to provide public utility transmission providers with flexibility in addressing operational challenges that may arise during the transition to intra-hourly scheduling without jeopardizing reliability.

8. We grant EEI's request for an extension of time for compliance with Order No. 764. The Commission finds good cause to extend the compliance deadline in order to allow public utility transmission providers to implement to reforms set forth in Order No. 764 outside of the summer peak season. The Commission therefore extends the compliance period, with compliance filings now due by November 12, 2013.

III. Requests for Clarification and Rehearing

9. The following parties sought clarification and/or rehearing of various portions of Order No. 764: APPA, Florida Municipal Power Agency, and Public Power Council (collectively, Public Power); American Wind Energy Association (AWEA); Bonneville Power Administration (Bonneville); Iberdrola Renewables, LLC (Iberdrola); NRECA; Powerex Corporation (Powerex); and Public Interest Organizations (PIOs).[9]

A. Intra-hour Scheduling Reform

10. In Order No. 764, the Commission amended 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.[10] This reform was designed 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, and other changes in load profiles and system conditions.[11] The Commission implemented this reform to ensure that charges for generator imbalance service under Schedule 9 of the *pro forma* OATT and for other ancillary services through

[9] Public Interest Organizations are: Alliance for Clean Energy New York; Citizens Utility Board of Wisconsin; Climate and Energy Project; Conservation Law Foundation; Energy Conservation Council of Pennsylvania; Environment Northeast; Environmental Defense Fund; Great Plains Institute; Natural Resources Defense Council; Pace Energy and Climate Center; Sustainable FERC Project; Sierra Club; Union of Concerned Scientists; The Wilderness Society; Western Grid Group; Western Resource Advocates; and Wind on the Wires.

[10] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 91.

[11] *Id.* P 92.

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which reserve-related costs are recovered are just and reasonable and are not unduly discriminatory. The Commission received requests for rehearing and clarification of several discrete aspects of this requirement.

1. Applicability of Intra-hour Scheduling

a. Order No. 764

11. In the Final Rule, the Commission stated that it expects that many types of entities, not only VERs, may benefit from the availability of intra-hour scheduling. The Commission further explained:

> 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 forced outage 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…. [T]he 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.[12]

b. Requests for Rehearing/Clarification

12. Several commenters request that the Commission clarify the applicability of the intra-hour scheduling reform adopted in Order No. 764. Public Power requests the Commission clarify that 15-minute scheduling is available: (1) to Network Integration Transmission Service (NITS) customers to the extent they are subject to scheduling requirements for their network resources; and (2) for scheduling secondary network service under Part III of the *pro forma* OATT. Public Power states that the intra-hour scheduling reform requires amendments to sections 13.8 and 14.6 of the *pro forma* OATT, which are provisions in Part II of the OATT that relate to point-to-point transmission service. Public Power observes that no changes are required under Part III of the tariff specifically addressing NITS, yet there are statements made in Order No. 764

[12] *Id.* P 94.

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that indicate that the intra-hour scheduling reform would be available for all customers.[13] Public Power contends that while the Commission did not specifically address the applicability of the intra-hour scheduling reform to NITS, it did indicate a strong intent to reach all transmission customers; only in doing so would Order No. 764 achieve its goals of ensuring just, reasonable and not unduly discriminatory service.

13. Moreover, Public Power argues that a customer using secondary network service and a customer using point-to-point transmission service are subject to the same generator imbalance charges.[14] Therefore, Public Power contends that if NITS customers are unable to utilize intra-hour scheduling, they would be exposed to excessive imbalance charges. Public Power also argues that consistent scheduling practices across transmission systems are necessary to ensure that intra-hour scheduling is available for VERs that rely on both point-to-point and network service to deliver energy across multiple systems.

14. AWEA and Iberdrola seek clarification that the Commission intends for all point-to-point transmission customers, including those using point-to-point transmission service to schedule to loads, to have the option to use intra-hour scheduling.[15] AWEA requests that the Commission clarify that load-serving entities that use point-to-point transmission service to deliver energy from adjacent transmission service providers to load are eligible to use intra-hour scheduling.

c. Commission Determination

15. The Commission clarifies that the intra-hour scheduling reform adopted in the Order No. 764 applies to *all* transmission customers that schedule transmission service under the OATT. This includes load serving entities, entities using point-to-point transmission service to schedule to loads, and transmission customers using network service. Order No. 764 should not be read to limit the scope of transmission customers eligible to use the intra-hour scheduling reform, but instead should be read as allowing any customer that schedules transmission service to adjust those schedules on a 15-minute basis. The Commission believes this clarification to be consistent with the scope of Order No. 764 and does not require any further changes to the *pro forma* OATT to

[13] Public Power at 3 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at PP 2, 94,151).

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

[15] Iberdrola at 3-4; AWEA at 3-4.

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allow all transmission customers taking service under the *pro forma* OATT to adjust transmission schedules on a 15-minute basis.

2. Calculation of Imbalance Charges

a. Order No. 764

16. In Order No. 764, the Commission explained that the intra-hour scheduling requirement applies only to scheduling practices, and that transmission providers may continue to calculate imbalance charges on an hourly basis.[16] The Commission explained, however, that the metric against which generator imbalances are measured will be more granular than under current hourly scheduling protocols.

17. The Commission rejected requests to reform the imbalance settlement time period, recognizing the costs associated with such changes. However, the Commission explained that if a public utility transmission provider believes that aligning the imbalance settlement interval with the intra-hour scheduling interval or implementing sub-hourly dispatch will lead to more efficient operations, provide appropriate price signals to customers, or address other potential issues, it may seek the necessary authorizations to do so from the Commission under section 205 of the Federal Power Act (FPA).[17]

b. Requests for Rehearing/Clarification

18. Iberdrola and AWEA argue that in the absence of sub-hourly settlement and dispatch requirements, the Commission should clarify how intra-hour scheduling information will factor into the calculation of Schedule 9 charges. Iberdrola states that while the Commission asserted that "the metric against which generator imbalances are measured will be more granular than under current hourly scheduling protocols," it did not provide specifics regarding the manner in which generation imbalance should be measured and/or calculated as a result of the new requirement.[18] Accordingly, Iberdrola and AWEA request that the Commission clarify that public utility transmission providers are required to average a transmission customer's intra-hour schedules to determine the hourly imbalance charged, or credited, over a given hour.[19] Iberdrola and AWEA

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[16] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 104.

[17] *Id.* P 105.

[18] Iberdrola at 2-3 (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 105).

[19] Iberdrola at 2-3; AWEA at 2-3.

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contend that this clarification will ensure that the intra-hour schedules are properly factored into the hourly scheduled amount, thereby minimizing the overall hourly schedule deviation and any associated imbalance penalty charge.

c. Commission Determination

19. The Commission agrees with Iberdrola and AWEA that, in the absence of sub-hourly settlement and dispatch, a public utility transmission provider must account for intra-hour imbalances in order to ensure that they are properly factored into the calculation of hourly imbalance charges. As Iberdrola notes, the Commission in Order No. 764 intended that the use of 15-minute scheduling will cause the metric against which generator imbalances are measured to be more granular when compared to the use of hourly scheduling. To the extent a transmission customer using 15-minute scheduling is taking service from a public utility transmission provider with hourly imbalance charges, the public utility transmission provider would calculate the hourly imbalance volume by averaging the imbalances during each 15-minute scheduling interval over the hour, which is equivalent to what Iberdrola and AWEA described in their requests for clarification.[20]

3. Curtailment Priority

a. Order No. 764

20. In Order No. 764, the Commission did not propose any changes to curtailment priorities or the available transmission capacity (ATC) calculation to accommodate intra-hour transmission schedules.[21] The Commission recognized that when a public utility

[20] The calculation of average hourly imbalances is the same whether one uses (a) the average of the four separate 15-minute imbalances within the hour, or (b) the difference between the average of the scheduled amounts over the four 15-minute intervals and the average of the actual generation during the same period. Consider the following example: there are four 15-minute schedules of 10MW, 11MW, 9MW, and 10MW, with four 15-minute actual usages of 10MW, 12MW, 10MW, and 9MW. The difference between these schedules and actual usages results in four 15-minute imbalances of 0MW, -1MW, -1MW, and +1MW. The average of the four 15-minute imbalances is (0-1-1+1)/4 = -0.25MW. This is identical to taking the difference of the average hourly scheduled amounts ((10+11+9+10)/4 = 10MW) and the average hourly actual usage ((10+12+10+9)/4 = 10.25MW). This difference is (10MW – 10.25MW) = -0.25MW.

[21] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 136.

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transmission provider makes unscheduled transmission service available after firm schedules have been received, the application of curtailment rules and the ATC calculation may become more complicated. However, the Commission indicated that this is already the case under hourly scheduling, and it reiterated that transmission schedules for firm service will continue to have curtailment priority over schedules for non-firm service.[22]

21. In response to comments on whether a review of standards or business practices is necessary to implement 15-minute scheduling, the Commission found no North American Electric Reliability Corporation (NERC) standards or NAESB business practices that would prevent industry from implementing intra-hour scheduling.[23] The Commission stated that to the extent industry believes it is beneficial to refine one or more standards or business practices to reflect intra-hour scheduling, industry can use existing processes to pursue such refinements.

b. Requests for Rehearing/Clarification

22. Powerex asks the Commission to clarify what it meant in saying that, "all transmission schedules for firm service will continue to have curtailment priority over all schedules for non-firm service."[24] Powerex urges the Commission to clarify whether the submission of firm intra-hour schedules will displace non-firm hourly schedules on constrained paths. Powerex also requests that the Commission require the North American Energy Standards Board (NAESB) to adopt business practice standards that establish the priority of firm intra-hour schedules over non-firm hourly schedules.

c. Commission Determination

23. The Commission confirms that schedules for firm transmission service will continue to have curtailment priority over schedules for non-firm transmission service.[25]

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[22] *Id.* P 136 & n.173 (noting that section 14.5 of the *pro forma* OATT clearly states 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").

[23] *Id.* P 146.

[24] Powerex at 10 (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 136).

[25] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 136.

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Powerex provides no reason why a non-firm hourly schedule should have priority over a firm schedule submitted within the hour. We reiterate that a firm transmission schedule should be treated as firm and retain curtailment priority over a non-firm transmission schedule. Thus, firm transmission schedules have priority over non-firm transmission schedules for 15-minute intervals, just as they currently have for hourly intervals. To the extent Powerex believes that refinements to standards or business practices are needed to account for intra-hour schedule changes, it should work through the relevant standards body to develop standards or business practices related to transmission schedule curtailment priorities.

4. Customer Benefits of Intra-hour Scheduling

a. Order No. 764

24. In Order No. 764, the Commission indicated that over time, the implementation of intra-hour scheduling should allow public utility transmission providers to rely more on planned scheduling and dispatch procedures, and less on reserves, to maintain overall system balance. The Commission further explained that:

> 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…. 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.[26]

b. Requests for Rehearing/Clarification

25. Iberdrola contends that the intra-hour scheduling reform focuses not only on the beneficial impacts intra-hour scheduling can have on a VER generators' exposure to generation imbalance charges, but also recognizes the benefits that all point-to-point transmission customers would receive from this capability. Specifically, Iberdrola points to the Commission's expectation that Order No. 764 would ensure that "other ancillary services through which reserve related costs are recovered are just and reasonable and not

[26] *Id.* P 96.

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unduly discriminatory."[27] Iberdrola seeks clarification that, to the extent 15-minute scheduling reduces the reserve requirements for other ancillary services (specifically Schedules 3 and 4), customers will benefit from reduced reserve-related costs and reduced exposure to regulation and imbalance charges.

c. Commission Determination

26. As indicated by the above-quoted passage from Order No. 764, use of intra-hour scheduling can reduce the amount of imbalance energy for which a balancing authority is potentially responsible and, in turn, lower reserve-related costs. Such benefits could manifest themselves in the form of reduced regulation charges under Schedule 3 of the *pro forma* OATT as well as any other ancillary service schedule through which a public utility transmission provider recovers the costs of capacity needed to provide generator imbalance service. Moreover, to the extent a transmission customer uses intra-hour scheduling to reduce the total imbalance charges it may incur under Schedule 4 of the *pro forma* OATT, that customer would directly benefit from the proposed reform.

B. Data and Forecasting Reform

27. In Order No. 764, the Commission required public utility transmission providers to modify their *pro forma* LGIAs to require new interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider where necessary for that public utility transmission provider to develop and deploy power production forecasting. In requiring this change to the *pro forma* LGIA, the Commission decided not to modify existing LGIAs, in part because doing so would be administratively burdensome.[28] The Commission received one request for rehearing of this requirement.

1. Order No. 764

28. In Order No. 764, the Commission required each public utility transmission provider to incorporate provisions into the *pro forma* LGIA requiring interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider for the purpose of power production forecasting. Specifically, the Commission required public utility transmission providers to revise article 8.4 of the LGIA to provide that reporting requirements for

[27] Iberdrola at 4 (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 91).

[28] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 195.

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meteorological and forced outage data would be set forth in Appendix C, Interconnection Details, of an LGIA.[29]

29. In requiring this change to the *pro forma* LGIA, the Commission decided not to modify existing LGIAs, in part because doing so would be administratively burdensome. The Commission noted that nothing in 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.[30] To the extent that the parties are unable to agree to modifications of Appendix C, the Commission acknowledged that article 30.11 of the *pro forma* LGIA gives the transmission provider the right to make a unilateral filing to the Commission proposing to modify an existing LGIA under section 205 of the FPA.[31]

2. Request for Rehearing/Clarification

30. Bonneville requests that the Commission clarify that transmission providers have the unilateral right to amend Appendix C of the LGIA to include data reporting requirements. Bonneville cites a Commission order in which the Commission found that Bonneville's proposal to clarify that the transmission provider has the unilateral right to modify Appendix C as control area requirements change was unnecessary because Article 9.3 already gives the transmission provider the right to unilaterally amend Appendix C for operational requirements.[32] Bonneville cites the following passage from the Safe Harbor Order:

> While the Interconnection Customer does have the right to agree to modifications to the agreement, the LGIA should be read as granting the Transmission Provider the right to determine the applicable reliability criteria. Moreover, under LGIA article 9.3 (Transmission Provider Obligations), the *Transmission Provider has the responsibility for establishing*

[29] *Id.* P 193.

[30] *Id.* P 195 (noting 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).

[31] *Id.*

[32] Bonneville at 10 (citing *Bonneville Power Admin.*, 112 FERC ¶ 61,195 (2005) (Safe Harbor Order)).

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> *the Interconnection Customer's operating instructions and operating protocols and procedures*. Because these instructions, protocols, and procedures will include reliability requirements, *article 9.3 already gives the Transmission Provider responsibility for modifications to Appendix C*. The same provision gives the Interconnection Customer the right to propose changes for the Transmission Provider to consider, but not the right to make unilateral changes. In light of this provision, *we conclude that BPA's proposed change is unnecessary*. . . .[33]

In light of the Safe Harbor Order, Bonneville urges the Commission to clarify Order No. 764 to state specifically that transmission providers have the unilateral right to amend Appendix C of the LGIA to include data reporting requirements.

31. Alternatively, Bonneville urges the Commission to clarify that the requirement of mutual agreement or a filing under section 205 of the FPA does not apply to non-jurisdictional transmission providers because section 205 does not apply to non-jurisdictional transmission providers such as Bonneville. Bonneville argues that the ability to unilaterally amend Appendix C is essential for non-jurisdictional transmission providers. Bonneville states that if the Safe Harbor Order had not granted Bonneville the right to unilaterally amend Appendix C for operational requirements, Bonneville might not have sought reciprocity safe harbor status with the Commission. Bonneville further states that without the ability to make unilateral changes to Appendix C of the LGIA for operational requirements, Bonneville may not be able to implement the rule's data reporting requirements and continuously obtain the data required from VERs.[34]

32. To the extent that the Commission does not grant either of these clarifications, Bonneville seeks rehearing. Bonneville states that it relied on the Safe Harbor Order in seeking safe harbor status and entering into interconnection contracts with multiple generators. Bonneville argues that the Commission failed to explain its departure from the Safe Harbor Order, which Bonneville contends results in an arbitrary and capricious

[33] Safe Harbor Order, 112 FERC ¶ 61,195 at P 20 (emphasis added by Bonneville).

[34] Bonneville at 11-12 (noting that Bonneville has more than 4,900 MW of existing VER generation on its system).

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order, especially where there are "serious reliance interests that must be taken into account."[35]

3. Commission Determination

33. We deny Bonneville's requests for clarification or rehearing. The data provision requirements established in Order No. 764 require interconnection customers to provide public utility transmission providers with a specific set of data (i.e., meteorological and forced outage data) to be set forth in Appendix C of the LGIA. The Commission directed that these data provision requirements apply only to new interconnection agreements. Recognizing that there may be instances where transmission providers wish to incorporate these provisions into existing LGIAs, the Commission explained that such changes could be accomplished in one of two ways: (1) through mutual agreement with the interconnection customer, or (2) through a unilateral filing with the Commission under section 205 of the FPA, as contemplated by article 30.11 of the LGIA.[36]

34. In its request for rehearing, Bonneville urges the Commission to clarify, notwithstanding the Commission's determination in Order No. 764, that transmission

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[35] *Id.* at 12 (citing *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009)).

[36] Article 30.11 of the *pro forma* LGIA states:

> Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

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providers have the unilateral right to amend Appendix C of the LGIA to include Order No. 764's data reporting requirements. Bonneville's argument is based on the Safe Harbor Order's holding, quoted at length above, that interpreted article 9.3 of the LGIA to give transmission providers the responsibility for modifying Appendix C of the LGIA to establish the interconnection customer's operating instructions, protocols, and procedures, which include reliability requirements.[37]

35. In Order No. 764, the Commission recognized that power production forecasts could yield significant benefits if incorporated into scheduling and unit commitment processes.[38] The Commission noted, however, that such forecasts are only as good as the data upon which they rely. The Commission also concluded that the current lack of meteorological and forced outage data reporting requirements in the *pro forma* LGIA may limit the efforts of transmission providers to manage operating costs more efficiently.[39] Therefore, in Order No. 764 the Commission revised the *pro forma* LGIA for new interconnection customers to require inclusion of certain data in those LGIAs. The Commission concluded that such information will enable transmission providers to commit resources providing reserves more accurately, thereby ensuring that reserve-related charges remain just, reasonable, and not unduly discriminatory.[40]

36. The Commission then specified how the data should be added to existing and new LGIAs, finding that it would be administratively burdensome on public utility transmission providers and interconnection customers, especially where the public utility transmission provider is not engaged in power production forecasting, to apply Order No. 764 retroactively to existing agreements.[41] The Commission found in Order No. 764

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[37] Safe Harbor Order, 112 FERC ¶ 61,195 at P 20.

[38] Order No. 764, FERC Stats, & Regs. ¶ 31,331 at P 172 (referencing National Renewable Energy Laboratory, *Western Wind and Solar Integration Study* ES-18 (2010), *available at* http://www.nrel.gov/wind/systemsintegration/wwsis.html. In addition, NERC has recommended that forecasting techniques be incorporated into day-to-day operational planning and real-time operations routines/practices including unit commitment and dispatch. North Am. Elec. Reliability Corp., *Accommodating High Levels of Variable Generation* 54 (2009), *available at* http://www.nerc.com/files/IVGTF_Report_041609.pdf).

[39] *Id.* at P 173.

[40] *Id.*

[41] *Id.* P 195.

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that the provision of the specified data for the performance of meaningful forecasting and the process by which it should be included in LGIAs will assure just and reasonable rates and avoid undue discrimination. Therefore, the Commission concludes that Order No. 764 limits the unilateral right that Bonneville asserts flows from the Safe Harbor Order's interpretation of article 9.3 with regard to the issues addressed in Order No. 764—i.e., with regard to meteorological and forced outage data provision requirements and the procedures for including them in LGIAs as addressed in Order No. 764. Allowing transmission providers unilateral rights to act in a manner inconsistent with the findings in Order No. 764 could result in the provision of services in an unduly discriminatory manner and at rates that are unjust and unreasonable.

37. The reason for requiring revisions to Appendix C of existing LGIAs that incorporate the specific set of data described in Order No. 764 to be made either through the mutual agreement of the parties or through a filing with the Commission is so that the Commission can ensure that any such changes are made in a just, reasonable, and not unduly discriminatory manner. In Order No. 764, the Commission established a flexible approach regarding the specific data that would be required from individual customers, in which public utility transmission providers and interconnection customers are expected to negotiate in the first instance.[42] Moreover, the Commission recognized the potential that certain data reporting requirements could result in increased costs to the interconnection customer.[43]

38. While new interconnection customers will be in a position to work out the details of the meteorological and forced outage data prior to developing their projects, existing interconnection customers are not in the same position. It would be unfair to allow public utility transmission providers to unilaterally impose unexpected costs associated with data reporting provisions on existing interconnection customers without being required to make at least some showing that specific data sought by the transmission provider (and the associated costs) are just and reasonable.

39. We also deny Bonneville's alternative request for clarification or rehearing, which urges the Commission to clarify that the requirement of mutual agreement or a section 205 filing for inclusion of the data reporting requirements addressed above in existing LGIAs does not apply to non-jurisdictional transmission providers. Order No. 764 does not apply to non-jurisdictional entities such as Bonneville unless such entities seek to qualify for, or maintain safe harbor status.[44] To the extent Bonneville

[42] *Id.* PP 175-76.

[43] *Id.* n.207.

[44] *Id.* P 377.

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seeks to qualify for, or maintain safe harbor status, and wants to include the data reporting requirements addressed above in its existing LGIAs and Bonneville's customers disagree with the inclusion, Bonneville may seek to incorporate these data reporting requirements into existing LGIAs through a petition for declaratory order. In such case, Bonneville would need to demonstrate that its proposal substantially conforms or is superior to the Commission's *pro forma* LGIA. In such a filing, the Commission would be in a position to consider facts and circumstances unique to Bonneville (such as the high penetration of VER interconnection customers) in the context of Bonneville's tariff as a whole.

C. Generator Regulation Service

40. In Order No. 764, the Commission declined to adopt the proposed Schedule 10 component of the Proposed Rule.[45] Instead, the Commission indicated that it would continue its current policy of evaluating proposals to recover capacity costs incurred to provide Schedule 9 generator imbalance service on a case-by-case basis. However, in light of the disparate views on the generator regulation service in comments on the Proposed Rule, the Commission provided guidance on the proper design of a generator regulation service charge.[46] The Commission received requests for rehearing or clarification regarding several aspects of the guidance provided in Order No. 764.

1. Case-by-Case Approach to Generator Regulation Service Proposals

a. Order No. 764

41. 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. In response to these comments, Order No. 764 maintained the Commission's existing approach of evaluating individual proposals to recover the capacity costs incurred to provide generator imbalance service on a case-by-case basis.[47] The Commission explained that this result allowed public utility transmission providers to retain the flexibility needed to propose capacity services that best respond to the needs of their customers; it also avoided requiring them to expend resources to adopt the one-

[45] *Id.* P 268.

[46] *Id.* PP 315-335.

[47] *Id.* PP 268-269. The Commission specifically withheld comment on whether additional reforms to contingency reserves were necessary. *Id.* P 342.

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size-fits-all generator regulation service discussed in the Proposed Rule. The Commission set forth guiding principles that public utility transmission providers should take note of in 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.[48]

b. Requests for Rehearing/Clarification

42. PIOs argue that the end result of Order No. 764 is to permit the imposition of unjust and unreasonable rates by allowing public utility transmission providers to charge VERs directly for integration costs while allowing other generation integration costs to be spread system-wide, resulting in unlawful discrimination. PIOs argue that by permitting public utility transmission providers "to impose Schedule 10-type of service charges," Order No. 764 reflects unsound regulatory policy.[49] PIOs argue that the guidance set forth in Order No. 764 on how such generator regulation charges should be developed is unworkable, and that the service itself is too expensive, complex, and may not be necessary in light of the other reforms adopted in Order No. 764. PIOs contend that, at a minimum, the Commission should prohibit public utility transmission providers from implementing such a service for at least two years after the effective date of Order No. 764 in order to provide sufficient time for the other reforms to be implemented and their effects studied.

43. PIOs suggest that Order No. 764 allows public utility transmission providers to charge VERs for their contribution to system variability while allocating the costs of the variability of conventional generators across all system customers, which PIOs believe to unduly discriminatory and in contravention of section 205 of the FPA. PIOs contend that both VERs and conventional generators share attributes of uncertainty and variability, asserting that thermal generators routinely fail to start, trip offline, and vary from their schedules. PIOs further contend that "dispatchability" is not a consistent distinction between the two categories of generators, as some VERs can be dispatchable.[50] PIOs disagree with the Commission's conclusion in Order No. 764 that VERs are not similarly situated to conventional, dispatchable generation for purposes of evaluating the need to implement the reforms adopted therein.[51] PIOs assert that the only support given by the

[48] *Id.* P 317.

[49] PIOs at 8.

[50] *Id.* at 5-6 (citing instances where public utility transmission providers require generators, including VERs, to be dispatchable).

[51] *Id.* at 5-6 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 47).

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Commission when recognizing that VERs are not similarly situated to conventional generators was the Commission's definition of VERs set forth in Order No. 764.[52] PIOs argue that the Commission cannot support its conclusion using only this definition of VERs. PIOs argue that the Commission erred to the extent that it intended the general assertion that VERs are not similarly situated to conventional generation to be determinative as to the specific issue of both uncertainty and variability. PIOs argue that the Commission provided no factual or economic support for this assertion, nor does the Commission tie the statement to the discussion of Schedule 10-type regulation service. PIOs contend that all generators impose integration costs on a transmission system, and that the Commission should allocate all such costs to all customers in a service territory, rather than allowing public utility transmission providers to allocate different generator regulation charges to different sets of customers.[53] PIOs argue that the Commission should amend Order No. 764 to prohibit public utility transmission providers from charging different volumetric reserve requirements to different customers.

44. PIOs state that if the Commission does not grant rehearing on these points, it should, at a minimum, condition any Schedule 10-type service on the public utility transmission provider utilizing a design that reflects the following two options.[54] First, PIOs argue that the Commission could require public utility transmission providers to implement a slower reserve service (akin to load-following or spinning reserves). Second, PIOs argue that the Commission could require that the regulation service be 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. Expanding on this point, PIOs argue that the Commission's use of the term "regulation" is imprecise and could include both seconds-to-minutes, and minutes-to-hours. PIOs argue that Schedule 10 rates for all schedule variations within an hourly period is likely to be unjust and unreasonable, and therefore PIOs urge the Commission to oppose it here.

45. PIOs also argue that Order No. 764 failed to expressly address how the six principles applicable to any Schedule 10-type filing will ensure that the proposal is not unduly discriminatory toward VERs.[55] PIOs believe that the Commission should establish a technical conference to address the operational issues associated with the

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[52] *Id.* at 6 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at n.1).

[53] *Id.* at 10-12 (citing AWEA, Comments on Proposed Rule at 28-32).

[54] *Id.* at 13-14.

[55] *Id.* at 13.

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implementation of a Schedule 10-type service as well as the six principles discussed in Order No. 764. PIOs allege that the Commission ignored requests for a technical conference in Order No. 764.

c. Commission Determination

46. The Commission finds that PIOs' concerns have been thoroughly considered and addressed in this proceeding and that PIOs' request for a finding that VERs are no different from other generators is misplaced at this time. As a general matter, all transmission customers are required to account for ancillary services in a similar manner. To the extent that a public utility transmission provider proposes to allocate to VERs their share of system variability, it must also allocate to all other generation resources as transmission customers their corresponding share of system variability.[56]

47. Where appropriate, the Commission has recognized how the unique characteristics of VERs can inform regulatory policies.[57] Within the context of this proceeding, we continue to believe that the fact-intensive nature of public utility transmission provider proposals to implement a generator regulation charge with a differentiated rate justifies a case-by-case review of such proposals. At that time, the Commission would be in a position to determine the ways in which a public utility seeks to apply different generator regulating reserves to different customers (or customer classes), and whether such rates accurately reflect the customers' proportionate share of the public utility transmission provider's overall regulation needs.[58] Moreover, such individual cases are the appropriate place to evaluate the extent to which different customers may impose such a degree of variability or uncertainty on a transmission system that they merit different generator regulating rates.

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[56] Order No. 764, 139 FERC ¶ 61,246 at P 320.

[57] *See, e.g., Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at PP 663-666, *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). (recognizing the limited ability of intermittent generators to precisely forecast or control generation levels); *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) (adopting a package of interconnection standards applicable to large wind generators).

[58] Order No. 764, FERC Stats & Regs. ¶ 31,331 at P 320.

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48. Order No. 764 implemented a *minimum* set of requirements applicable to *all* public utility transmission providers that would build on existing regional efforts to address VER integration.[59] Within individual cases, a public utility transmission provider seeking to allocate the cost of generator regulation service to customers based on their responsibility for those costs must show that the rates for any such service are just and reasonable. In making this showing, the public utility transmission provider may propose additional operational reforms or other complementary services, such as following or spinning reserve services, as warranted for its particular circumstances. At the same time, transmission customers may advocate that additional reforms should be implemented. Based on the record in an individual proceeding, the Commission will determine whether such additional operational reforms or complementary services are necessary to ensure that the public utility transmission provider's rates remain just and reasonable and not unduly discriminatory. The public utility transmission provider will be expected to reduce the costs of generator regulation service to the extent practicable[60] and allocate such costs based on transmission customers' proportionate share of responsibility.[61]

49. While we acknowledge that the Commission did not explicitly repeat in Order No. 764 each of PIOs' arguments in response to the Proposed Rule, we did consider and respond to the substance of their arguments by: (1) not adopting the proposed reform to which PIOs objected; (2) allowing for flexibility in how any capacity service would be designed and thereby not prescribing that all public utility transmission providers must provide the regulation-type service to which PIOs object; and (3) setting forth guidelines that will ensure that future proposals to implement generator regulation charges with differentiated rates are just, reasonable, and not unduly discriminatory.

50. For these reasons, we will not make the determinations sought by PIOs on rehearing because the record in this proceeding leads us to believe that generator regulation services are best addressed on a case-by-case basis, where the specific facts and circumstances of a public utility transmission provider's system and its proposed generator regulation service can be explored.[62] Nor will we adopt the additional

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[59] *Id.* P 24 (*emphasis added*).

[60] *Id.* PP 321-23.

[61] *Id.* P 320.

[62] *See Westar Energy Inc.*, 130 FERC ¶ 61,215, at P 36 (2010), *order on reh'g*, 137 FERC ¶ 61,142 (2011) (*Westar*) (accepting a proposal by a public utility transmission provider to assess intermittent generators higher regulation costs in a manner consistent with cost causation principles); *PacifiCorp*, 136 FERC ¶ 61,092

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conditions and two-year waiting period advanced by PIOs. The Commission was mindful of these suggestions when developing Order No. 764. Indeed, the Commission found in Order No. 764 that the requirement for public utility transmission providers to offer shorter, 15-minute scheduling would tend to reduce the amount of capacity that source balancing authorities would need to maintain.[63] However, upon evaluating the competing interests of different industry participants, including those raised by PIOs here,[64] the Commission concluded that its existing case-by-case approach provided the necessary flexibility for capacity services to be tailored to the particular needs of a transmission system.

51. Likewise, rather than establishing time periods before allowing public utility transmission providers to implement a generator regulation service, the Commission sought to achieve a balanced approach that emphasizes public utility transmission providers' obligation to take the intra-hour scheduling and forecasting reforms into account in supporting any such proposal.[65] The Commission stated that "[i]n 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."[66] Thus, while the Commission will consider the extent to which additional reforms might mitigate a public utility transmission provider's reserve costs, there is no need for a two-year wait-and-see period. Public utility transmission providers are entitled to an effective opportunity to recover the costs of providing service,[67] and we will not foreclose their option to seek such cost-recovery for reasonably incurred reserve costs. However, in light of the potential for the reforms in Order No. 764 to result in additional cost savings over time,[68] the Commission will be open to considering whether a public utility

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(2011) (setting a proposed generator regulation service rate schedule, among other things, for hearing and settlement procedures); *Puget Sound Energy, Inc.*, 137 FERC ¶ 61,063 (2011) (setting a proposed generator regulation service rate schedule that charges different rates for different customers for hearing and settlement procedures).

[63] Order No. 764, 139 FERC ¶ 61,246 at PP 95-96.

[64] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at PP 248-50.

[65] *Id.* PP 322-325.

[66] *Id.* P 334.

[67] *Id.* P 324.

[68] *See, e.g., id.* PP 95-96.

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transmission provider should be required to update its rates to reflect the impact of these reforms over time to ensure that rates remain just and reasonable and not unduly discriminatory.

2. Load and Conventional Generation Anomalies and Cost Allocation

a. Order No. 764

52. In Order No. 764, the Commission recognized that calculating the relative impact of individual customers or customer classes on a public utility transmission provider's overall generator regulation reserve needs and allocating those costs accordingly could be difficult and complex.[69] Accordingly, Order No. 764 set forth specific guidance as to how the Commission expects proposals to implement a generator regulation service to be developed and supported. Among other things, the Commission explained:

> [T]o 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).[70]

53. The Commission further explained that "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."[71] The Commission described weather events, such as droughts that may affect the required quantity of generator regulation reserves more or less during different parts of the year as an example of such "diversity events."

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[69] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 317.

[70] *Id.* P 320.

[71] *Id.* P 321.

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b. Request for Rehearing/Clarification

54. AWEA seeks clarification of the guidance in Order No. 764 that proposals to implement generator regulation service should account for "diversity events" and data anomalies in the calculation of the quantity and allocation of generator regulation reserves.[72] AWEA asks the Commission to affirm that this includes the anomalous behavior of conventional generators and loads. AWEA states that a transmission service provider might argue that it should exempt a conventional generator's deviations from scheduled output during periods in which the conventional generator is ramping from one output level to another, or that a load schedule deviation caused by the behavior of a non-conforming industrial load is anomalous and should be excluded from the dataset. According to AWEA, such deviations can account for a sizeable share of the regulation burden of the power system. AWEA contends that excluding such deviations could bias the allocation of reserve costs away from conventional generators and loads, thereby imposing excessive and discriminatory costs on entities such as VERs.

c. Commission Determination

55. The Commission believes that Order No. 764 already addresses AWEA's concern. As the Commission explained in Order No. 764, once the overall quantity of regulation reserves is calculated for transmission customers, it should be allocated to individual customers (or customer classes) based on their "proportionate share," as determined by the operating characteristics of those customers (or customer classes).[73] However, we agree with AWEA that public utility transmission providers proposing a generator regulation charge must calculate their total regulating reserve need with respect to all operational causes that drive the need for regulating reserves. In the absence of system specific data, it would be difficult to determine whether certain behavior (such as the ramps and schedule deviations described by AWEA) is "anomalous." Thus, while we decline to make a *per se* finding here that any one customer (or customer class) or any one type of behavior is "anomalous," we emphasize that the public utility transmission provider must explain how the variations of all resources and loads are accounted for in its section 205 filing. To the extent AWEA believes that a public utility transmission provider has not justified how it accounts for all variations in a section 205 filing, AWEA may raise that issue in that proceeding.

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[72] AWEA at 4 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 224).

[73] Order No. 764, FERC Stats. & Regs. ¶ at P 320.

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3. Transmission Provider's Discretion & Deployment of Resources

a. Order No. 764

56. In Order No. 764, the Commission acknowledged comments seeking guidance on the extent to which power production forecasting would affect a differentiated rate structure under the proposed Schedule 10 generator regulation service. One commenter (Puget Sound Energy, Inc. (Puget)) sought clarification of the proposed Schedule 10 as to whether a transmission customer delivering from a VER would be required to schedule according to the public utility transmission provider's centralized power production forecast.[74]

57. The Commission responded to this comment by explaining that a transmission customer is responsible for the accuracy of transmission schedules and the public utility transmission provider is responsible for the reliability of its system.[75] The Commission also explained that power production forecasting is intended to inform the transmission provider regarding aggregate system variability that results from having VERs on its system, but it is not intended to replace transmission schedules from transmission customers delivering from VERs. The Commission further clarified that public utility transmission providers that use power production forecasts should use them to manage uncertainty in the same manner they use other forecasts of uncertainty for the transmission system.

58. Accordingly, the Commission declined to require transmission customers delivering from VERs to submit transmission schedules according to the public utility transmission provider's forecast. The Commission further stated:

> [T]he 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

[74] *Id.* P 302 (describing a comment stating 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).

[75] *Id.* P 328.

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> for inaccurate procurement of reserve requirements while the transmission customer retains the financial risk and responsibility for inaccurate schedules.[76]

b. Request for Rehearing/Clarification

59. Bonneville requests clarification that each transmission provider may determine how to use its forecasts to plan and deploy its resources. Bonneville explains that it is concerned with the statement in Order No. 764 that a transmission provider is obligated "to deploy its resources according to its own forecast in order to maintain the reliability of its system."[77] Bonneville indicates that VER power production forecasts have several uses, such as: (1) establishing an agreed-upon approach to scheduling; and (2) helping to ensure that reserve costs are minimized by identifying the likely range of reserves to be deployed and the direction of the reserve deployment. However, Bonneville believes that the transmission provider must deploy reserves in response to actual variability on its system, and it needs to consider factors beyond just the power production forecast.

60. For these reasons, Bonneville urges the Commission to clarify that, while power production forecasts may inform planning decisions, each transmission provider may determine how to use its forecasts to plan and deploy its resources. Alternatively, Bonneville contends that if the Commission intends to require a transmission provider to plan to deploy resources only according to its power production forecast, then the Commission should clarify that the transmission provider may limit the provision of generator imbalance service to the amount that it can supply from the resources it deployed in accordance with the forecast.[78]

c. Commission Determination

61. As the context for the statement highlighted by Bonneville indicates, the Commission did not require public utility transmission providers to deploy their reserves solely based on centralized forecasts, without regard to actual system conditions and circumstances. Rather, Order No. 764 pointed to centralized forecasts as a tool available to public utility transmission providers to manage system variability and the associated costs. The statement highlighted by Bonneville was made in order to differentiate the responsibilities and risks of transmission customers and public utility transmission

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[76] *Id.* P 331.

[77] Bonneville at 25 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 331).

[78] *Id.* at 26.

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providers regarding the manner in which they use forecasts. It was not intended to be a prescriptive statement that would limit the public utility transmission provider to deploying reserves based solely upon the forecast, without regard to other facts and system conditions.

62. Public utility transmission providers have a significant amount of flexibility in how they choose to incorporate centralized forecasts into their system operations. Consistent with Order No. 764, public utility transmission providers remain free to propose capacity services that best respond to the needs of their customers with the expectation 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.[79]

4. Financial Risk of Reserve Capacity Procurement

a. Order No. 764

63. In Order No. 764, the Commission recognized that there was disagreement on exactly how power production forecasting should be factored into public utility transmission providers' allocation of regulation reserves. Therefore, the Commission reserved judgment as to the appropriate power production forecasting requirements for a particular public utility transmission provider. At the same time, the Commission expressed its expectation 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 regulation reserves.[80] The Commission set forth the following policy guidance in order to assist public utility transmission providers in crafting any such proposals:

> [T]he 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

[79] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 325.

[80] *Id.*

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> 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.[81]

64. The Commission further described the appropriate division of responsibilities among public utility transmission providers and transmission customers, stating 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."[82] The Commission explained that "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."[83]

b. Request for Rehearing/Clarification

65. Bonneville contends that the Commission should clarify that while the transmission provider retains the responsibility for the reliable operation of its system, VER customers bear the risk of inaccurate reserve capacity procurement. Bonneville argues that this clarification is necessary because Order No. 764 places the risk and responsibility for the inaccurate procurement of reserve requirements on public utility transmission providers,[84] while at the same time requiring public utility transmission providers to use power production forecasts to identify the necessary amount of

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[81] *Id.* P 328.

[82] *Id.* P 331.

[83] *Id.*

[84] Bonneville at 6 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 331).

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reserves.[85] Bonneville contends that because these forecasts are based on data supplied by VER customers, they will only be as good as the data used to generate them. Bonneville argues that if the data are wrong, the forecasts will be wrong, causing the transmission provider to procure an incorrect amount of reserves. Bonneville further points out that even if the data are correct and generate an accurate forecast, the amount of reserves procured based on the forecast may not align with the amount actually needed for balancing VER customers.

66. Accordingly, Bonneville contends that VER customers should bear the costs of (1) excess reserves when the transmission provider acquires too many reserves based on a power production forecast; and (2) potentially expensive, short-term purchases when the transmission provider acquires too few reserves based on similar forecasting methods. Bonneville asserts that, alternatively, the transmission provider may have to resort to transmission curtailments to preserve system reliability and alleviate excess or inadequate energy flows.

67. To the extent that the Commission does not make this clarification, Bonneville seeks rehearing. Bonneville states that the Commission's conclusion that the transmission provider retains the risk and responsibility for inaccurate procurement of reserves creates an inequitable cost shift to other transmission customers.[86] Bonneville also contends that the Commission did not address its comments on this point in Order No. 764. In response to the Proposed Rule, Bonneville stated:

> Since the centralized forecast is based on the information provided from the VERs, is developed for the benefit of the VERs, and since the plant-specific components of the centralized forecast would ideally be used to establish VER schedules, VERs should bear the residual risk and costs associated with forecast error, which will not be completely eliminated, even through the deployment of state-of-the-art centralized forecasting systems. For example, the risks and costs associated with centralized forecast error would include generation imbalance charges that result from the difference between scheduled generation and actual generation. These costs reflect the nature of generation imbalances and should continue to be recovered from VER generation customers. In addition, *VERs should accept reasonable risks or costs*

[85] *Id.* (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 328).

[86] *Id.* at 8-9.

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> *associated with balancing reserve capacity shortfalls that may result from centralized forecast error, such as VER generation limitations or curtailments from the transmission provider or emergency balancing reserve capacity purchases. Allocation of such risks and costs to other transmission customers and rate payers would be inequitable and inconsistent with the principle of cost causation.*[87]

68. Bonneville urges the Commission to respond to these comments by granting rehearing and by holding that, if the transmission provider procures an incorrect amount of reserve capacity, either because the VER power production forecast is developed with inaccurate VER data or because VER scheduling practices do not correspond to predictions generated with VER data, VER customers assume the risk of those inaccuracies—both the economic risk associated with the costs of procurement and the risk of curtailments when needed to preserve reliability.

c. Commission Determination

69. As the Commission explained in Order No. 764, the public utility transmission provider must procure an amount of regulating reserves sufficient to manage the aggregate variability caused by the loads and resources on its system, taking into account offsetting deviations or "diversity benefits" among loads and resources.[88] In turn, the public utility transmission provider is entitled to recover the just and reasonable costs associated with providing these capacity reserves to its transmission customers. The obligation to procure generator regulation reserves did not change in Order No. 764.[89] Moreover, Order No. 764 affirmed the Commission's existing policy of allowing public utility transmission providers to allocate the costs of generator regulation service to customers based on their responsibility for those costs,[90] while at the same time requiring public utility transmission providers to reduce those costs to the extent practicable[91] and

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[87] *Id.* at 8 (citing Bonneville Comments on Proposed Rule at 50-51 (emphasis added)).

[88] Order No. 764, FERC Stats. & Regs. ¶ 21,331 at P 319.

[89] *Id.* P 270.

[90] *Id.* PP 269, 317-323.

[91] *Id.* PP 321-323.

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allocating them based on transmission customers' "proportionate share" of the responsibility.[92]

70. Order No. 764 pointedly determined that public utility transmission providers should remain free to propose capacity services that best respond to the needs of their customers,[93] and it clearly articulated the Commission's expectation that 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.[94] We believe this leaves adequate room for a public utility transmission provider to demonstrate that inaccurate data are leading to increased reserve costs and the public utility transmission provider should be able to recover such costs from customers causing them. Thus, we will not determine on a generic basis here that VER customers should bear the costs of excess reserves procured as a result of power production forecasting based upon poor quality data; nor will we find generically that VER customers should bear the costs of expensive, short-term purchases made because the transmission provider acquired too few reserves based on similarly poor data. The interplay between forecasting data quality and reserve cost allocation is more appropriately addressed in individual section 205 filings raising the issue.

5. Intra-Hour Scheduling Flexibility & Rate Design

a. Order No. 764

71. Order No. 764 allows public utility transmission providers to propose to recover and allocate generator regulation costs by way of a proposal under section 205 of the FPA.[95] The Commission provided guidance as to its expectations for such proposals, expressly stating that 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 (or groups of customers) to purchase or otherwise account for different quantities of generator regulating reserves.

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[92] *Id.* P 320.

[93] *Id.* P 268.

[94] *Id.* P 325.

[95] *Id.* P 333.

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b. Request for Clarification/Rehearing

72. Bonneville contends that the Commission should clarify that transmission providers may establish reserve requirements and commensurate rates based on historical *hourly* scheduling for VER customers that choose to switch between hourly and intra-hour scheduling instead of committing to intra-hour scheduling.[96] Bonneville contends that this clarification is important because transmission providers will be unable to make reductions in the amount of reserve capacity needed to meet the balancing needs of all VER customers if transmission providers have no certainty that VER customers will correct their scheduling error on an intra-hour basis.

73. Bonneville contends that the voluntary intra-hour scheduling requirement of Order No. 764 will not provide enough certainty for transmission providers to reduce operating reserves. Bonneville further contends that generator imbalance service charges do not provide sufficient incentives for VER customers to participate in voluntary 15-minute scheduling.[97] Bonneville therefore argues that mandatory intra-hour scheduling is the best way to ensure system-wide reductions in reserve capacity and cost savings for VER customers. Accordingly, Bonneville urges the Commission to acknowledge that there may not be cost savings if VER customers do not utilize intra-hour scheduling to correct their schedule error in every scheduling interval, and to clarify that transmission providers may establish options for VER customers to commit to schedule on an intra-hour basis.

74. Bonneville requests that the Commission ratify Bonneville's model through which VER customers may commit to make intra-hour schedule adjustments and to meet a level of scheduling accuracy that is predetermined and measurable, such as scheduling to an agreed-upon forecast or basing schedules on persistence scheduling assumptions. Under this approach, VER customers would be able to choose to commit to utilize intra-hour scheduling to correct their schedule error for every interval, or to choose to schedule on an hourly basis or mix of hourly and intra-hour scheduling. Bonneville explains that the consequence of choosing the option to switch between hourly and intra-hour scheduling, however, is that the VER customer will pay higher rates because the transmission

[96] Bonneville at 13.

[97] *Id.* at 15 (citing its own experience that despite generator imbalance service penalty charges, VER customers have not consistently utilized intra-hour scheduling to correct schedule error).

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provider will have to ensure sufficient reserve capacity is available at all times to balance a potential scheduling error based on historical *hourly* scheduling of VER customers.[98]

75. Bonneville contends that this approach is necessary to ensure that sufficient reserve capacity is available to meet system reliability needs and the potential scheduling errors of VER customers, while providing system operators with the flexibility to manage their systems efficiently. Bonneville further states that its requested clarification will ensure that the users of reserve capacity are allocated the costs associated with that capacity, consistent with the principle of cost causation.

c. Commission Determination

76. While we will not address the specifics of Bonneville's model here, we find as a general matter that whether a transmission customer commits to scheduling at every intra-hour interval can be a relevant consideration as to the quantity of reserves properly allocated to that customer. As indicated above, Order No. 764 explicitly envisions that public utility transmission providers should consider the extent to which customers use intra-hour scheduling in determining whether to require different transmission customers (or groups of customers) to purchase or otherwise account for different quantities of generator regulation reserves. Therefore, it follows that if a public utility transmission provider can show that transmission customers that schedule at every intra-hour interval impose less of a regulating burden than those customers that do not schedule as frequently, a different reserve requirement may be reasonable. However, because any such proposal would be necessarily fact-intensive and system specific, we will not address the specifics of Bonneville's proposal here. Instead, such proposals will be addressed on a case-by-case basis, as described in Order No. 764.[99]

77. Finally, we note that the Commission set forth a potential remedy for the problem described by Bonneville, i.e., that despite existing generator imbalance service penalty charges, VER customers do not use intra-hour scheduling to correct scheduling errors. Order No. 764 explained that if a public utility transmission provider believes it is necessary to address customers that intentionally deviate from their schedules, the public utility transmission provider may propose revisions to Schedule 9 generator imbalance service pursuant to section 205 of the FPA.[100] We affirm that decision here and further

[98] *Id.* at 16.

[99] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 269.

[100] *Id.* P 108 (noting that 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).

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note that even where deviations are not "intentional," public utility transmission providers may propose revisions to Schedule 9 generator imbalance service to address the effect of those deviations on reserve requirements.

6. Lack of Data & Higher Reserve Costs

a. Order No. 764

78. In Order No. 764, the Commission recognized the relationship between the use of power production forecasting and the allocation of generator regulation reserve quantities to a particular class of customers. The Commission found that: (1) the quantity of reserves used to provide generator regulation service can be managed most efficiently with the implementation of power production forecasting (as well as intra-hour scheduling) by public utility transmission providers; (2) 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; and (3) without the increased situational awareness of projected variability provided by power production forecasts, the public utility transmission provider's ability to efficiently commit or de-commit resources providing regulation reserves can be constrained, potentially resulting in rates for generator regulation service that are unjust and unreasonable or unduly discriminatory.[101]

b. Request for Rehearing/Clarification

79. Bonneville urges the Commission to clarify that it is not unduly discriminatory for transmission providers to impose higher generator regulation charges and larger reserve capacity requirements on VER customers that do not provide the data necessary to construct a forecast.[102] Bonneville argues that power production forecasts depend on information received from VER customers, and that the absence of data prevents transmission providers from producing a power production forecast. Bonneville states that Order No. 764 recognizes both the benefits of power production forecasting and the potential harm from not using forecasts. Noting that Order No. 764 limits the ability of transmission providers to collect data from existing customers, Bonneville argues that this lack of data requires the transmission provider to hold more reserve capacity.

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[101] *Id.* P 323.

[102] Bonneville at 26-27.

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c. Commission Determination

80. Order No. 764 recognized the contentious nature of proposals by public utility transmission providers to implement power production forecasting requirements and to allocate different reserve requirements to different transmission customers.[103] For this reason, the Commission reserved judgment as to the appropriate power production forecasting requirements for particular public utility transmission providers, with the expectation that such matters would be addressed in individual proposals to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves. Given the flexibility afforded by Order No. 764, public utility transmission providers are not precluded from attempting to demonstrate, for example, that the lack of data from some group of customers has a direct effect on the quality of their forecasts and the quantity of reserves they must retain, and thereby justifying a higher rate for that group of customers. Because such a proposal would require a fact-intensive inquiry unique to the public utility transmission provider's system, we decline to address it in the abstract here.

7. Curtailment & e-Tagging

a. Order No. 764

81. In Order No. 764, the Commission explained that its decision not to adopt a generic generator regulation rate schedule does not relieve public utility transmission providers of their obligation to maintain sufficient capacity to provide Schedule 9 generator imbalance service.[104] The Commission then reiterated the scope of a public utility transmission provider's obligation to provide Schedule 9 generator imbalance service that it established in the Order No. 890 proceeding. Specifically, the Commission explained that:

> [I]f 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

[103] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 324.

[104] *Id.* P 270 (citing *NorthWestern Corp.*, 129 FERC ¶ 61,116, at P 24 (2009), *order denying reh'g*, 131 FERC ¶ 61,202, at PP 17-18 (2010)).

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> obligation to acquire generator imbalance service as a condition of taking transmission service.[105]

82. The Commission explained that a public utility transmission provider can establish the amount of generator imbalance service and generator regulation service that it is capable of providing by either stating the maximum amount on its OASIS or by performing system impact studies on a case-by-case basis.[106] The Commission also reiterated when there are no additional resources available, the public utility transmission provider must accept the use of dynamic scheduling with a neighboring control area.[107] Moreover, the Commission explained its existing requirement for public utility transmission providers to allow customers to self-supply ancillary services.[108]

b. Requests for Rehearing/Clarification

83. Bonneville contends that the Commission should clarify that the transmission provider may limit the output of VER customers that are over-generating to their schedules, or curtail the schedules of VER customers that are under-generating to their actual output if it is not physically feasible for the transmission provider to provide additional reserve capacity from its resources or from third parties or to allow dynamic scheduling.[109]

84. Bonneville states that it is possible that a transmission provider may not be able to provide generator imbalance service where factors such as fuel or environmental constraints, maintenance, or other outages result in insufficient capacity to do so.[110] Bonneville further states that when a transmission provider is out of balancing reserve capacity (from its own resources as well as those in the marketplace), it is no longer able to absorb the difference between scheduled and actual output, and it must take other steps to keep its transmission system balanced, or else risk violating reliability standards or other legal requirements. Bonneville asserts that it would be inequitable for transmission

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[105] *Id.* (citing Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at PP 289-290).

[106] *Id.* PP 270-271 (noting that Order No. 764 does not place an obligation to build generation on public utility transmission providers).

[107] *Id.* n.277 (citing Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 290).

[108] *Id.* PP 273-274.

[109] Bonneville at 20.

[110] *Id.* at 20-21.

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customers that are not the source of these errors to bear the resulting cost. Bonneville concludes that when a transmission provider no longer has available balancing resources (of its own or from a third-party), it is appropriate to adjust the schedules or output of generating facilities whose scheduling errors have depleted the available balancing resources.

85. Bonneville explains that in the event of schedule curtailments, the sink balancing authority area or purchasing entity would need to deploy its own reserve capacity resources or resources available to it to maintain load and resource balance. Bonneville further explains that in order to maintain system reliability, the source and sink balancing areas need to exchange information about the likelihood of such events.[111]

86. Bonneville argues that these issues are not limited to Bonneville or the Pacific Northwest, asserting that they are ripe for a rulemaking because weather, system maintenance, market liquidity, and environmental obligations may affect transmission providers' ability to provide reserve capacity for generator imbalance service. Bonneville further contends that the likelihood for reserve capacity constraints increases as VER integration increases across the country.

87. To the extent that the Commission does not grant clarification, Bonneville requests that the Commission grant rehearing on this point.[112] Bonneville asserts that while the Commission acknowledged the possibility of reserve capacity limitations, it did not discuss how transmission providers should manage system reliability when they had no more reserve capacity and dynamic scheduling was not feasible.

88. Powerex urges the Commission to clarify that a transmission customer's discretion to submit schedules for transmission service does not override the transmission provider's right and responsibility to ensure that firm transmission schedules originating on its system are supported by sufficient reserves. Powerex expresses concern that Order No. 764 could be interpreted as providing transmission customers with unfettered rights to submit firm transmission schedules, regardless of their forecasted power production and/or the transmission system's available reserves.[113] Powerex argues that, by not requiring customers to schedule transmission service according to the transmission

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[111] *Id.* at 22 (noting that it provides customers information about the probabilities of curtailments given their preferred level of service, and has developed tools to provide real-time information regarding Bonneville's reserve capacity deployment).

[112] *Id.* at 22-23.

[113] Powerex at 5.

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provider's centralized forecast, while at the same time placing the transmission provider at risk for inaccurate procurement of reserves, Order No. 764 could be interpreted to mean that the customer's scheduling rights are unlimited, even where there is a demonstrable mismatch between a resource's expected production and its firm transmission schedules.

89. For these reasons, Powerex, urges the Commission to allow public utility transmission providers to deny transmission customers' firm schedules based on available reserves in a transparent and non-discriminatory fashion by: (1) advising customers in advance regarding the amount of balancing reserves the public utility transmission provider will provide; (2) specifying the portion of a VER's output that will be allowed to be firm, with any remaining amount being classified as non-firm; and (3) allowing customers to self-supply additional reserves in order to fully schedule all of their VER output.[114] Powerex argues that if the public utility transmission provider exhausts its established level of reserves, it should be permitted to deny firm e-Tags[115] in order to maintain reliability. Powerex further argues that the Commission should clarify that transmission customers' transactions must be properly e-Tagged (i.e., as to whether they are firm or non-firm) to ensure that sink balancing authorities are fully aware of the firmness of energy that they are receiving and whether they should procure additional reserves to back particular schedules.[116] To the extent the Commission is unwilling to make these clarifications, Powerex urges the Commission to make clear that customers that overstate firm schedules may be subject to substantial fines or penalties, including any fines or penalties that result from reliability events.

90. Powerex argues that these clarifications are critical because, in Powerex's experience, imbalance penalties and charges are not robust enough to deter deliberate generation imbalances in every single hour, as deliberate imbalances can be profitable in given market conditions. Powerex states that during periods when prices in an organized market such as California Independent System Operator Corporation (CAISO) are high, wind generators in the Pacific Northwest have a substantial economic incentive to submit schedules for their full output, even if they do not expect to fulfill those schedules.[117]

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[114] *Id.* at 5-6.

[115] E-Tags, also known as Requests for Interchange, are used by NERC and/or Regional Entities to schedule interchange transactions in wholesale markets.

[116] Powerex at 6.

[117] *Id.* at 7 (explaining that energy prices in CAISO can climb high enough that when the wind generators' firm schedules flow, the generator imbalance penalties

(continued…)

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Powerex posits that in this scenario, CAISO could unknowingly receive a large volume of energy that is e-Tagged as firm energy, relying on such energy to meet firm load in the CAISO balancing authority area, when in actuality the energy is not fully backed by sufficient VER output and reserves at the source balancing authority area. Powerex therefore argues that if the transmission provider expects that it may exhaust its established level of balancing reserves, the transmission provider should be able to deny firm e-Tags in order to maintain reliability, allowing customers to submit non-firm schedules instead.[118]

c. Commission Determination

91. The requests for clarification made by Bonneville and Powerex[119] both go to the extent of a public utility transmission provider's obligation to maintain sufficient reserves to provide generator imbalance service to transmission customers. The Commission has previously denied a proposal by a public utility transmission provider to disclaim its responsibility to offer generator regulation service for intermittent renewable generator export transactions.[120] Order No. 764 kept in place the Commission's policy of requiring public utility transmission providers to maintain sufficient reserves to provide generator imbalance service under Schedule 9 of the *pro forma* OATT.[121]

92. Both Bonneville and Powerex urge the Commission to limit a public utility transmission provider's obligation to provide this service to some pre-determined amount of reserves. We decline to make that determination in this proceeding, in which the Commission did not propose to modify and is not modifying the obligation previously set forth.

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combined with the cost of generator regulation service are still less than the price the wind generators will receive for such schedules).

[118] *Id.* at 6.

[119] Powerex filed an answer to Bonneville's request for clarification or rehearing. Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (2012), provides that the Commission will not permit answers to requests for rehearing. Accordingly, we will reject Powerex's answer.

[120] *NorthWestern Corp.*, 129 FERC ¶ 61,116, *order denying reh'g*, 131 FERC ¶ 61,202.

[121] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 270.

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93. Nevertheless, consistent with Powerex's request, we affirm our determination in Order No. 890-A, reiterated in Order No. 764, that a public utility transmission provider may, when it has exhausted all other options, establish the amount of generator imbalance service and generator regulation service that it is physically capable of providing by either stating the maximum amount on its OASIS or by performing system impact studies on a case-by-case basis.[122] To the extent that a public utility transmission provider seeks to curtail a transmission customer's transmission service due to a lack of balancing reserves, then it would have to show that it made the efforts specified by the Commission in Order No. 890-A, i.e., that it attempted to procure alternative balancing resources,[123] and where such resources are unavailable, it accepted the use of dynamic scheduling with a neighboring control area or allowed customers to self-supply the service.

94. We also note that Bonneville requests that it be allowed to curtail only VERs but makes no mention of curtailing other transmission customers. Under the *pro forma* OATT, curtailments are required to be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint and to network customers and transmission customers taking firm point-to-point transmission service on a basis comparable to the curtailment of service to the transmission provider's native load customers.[124] While Order No. 764 allows public utility transmission providers to require different customers to purchase or otherwise account for different amounts of regulating reserves, such distinctions must be reasonable and well-supported. Of course, the Commission would require similar evidentiary showings by a public utility transmission provider seeking to limit the reserves it would provide to any customer or class of customers.

95. We also decline to address the specifics of Powerex's concern regarding the scope of a transmission customer's discretion to submit schedules for transmission service at this time. Order No. 764 did not make any changes in the transmission customer's discretion to schedule transmission service that it has already reserved. Powerex describes a situation in which customers intentionally deviate from their schedules when it is economically beneficial for them to do so, even in light of the imbalance penalties

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[122] *Id.* PP 270-271.

[123] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 290 ("If it is not physically feasible for the transmission provider to offer generator imbalance service using its own resources, either because they do not exist or they are fully subscribed, the transmission provider must attempt to procure alternatives to provide the service....").

[124] Section 13.6 of the *pro forma* Open Access Transmission Tariff, *available at* http://www.ferc.gov/whats-new/comm-meet/2008/061908/E-1.pdf.

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they would incur. However, as discussed in other sections above Order No. 764 addressed this situation stating that if a public utility transmission provider believes it is necessary to address intentional deviations, it may propose revisions to Schedule 9 generator imbalance service pursuant to section 205 of the FPA.[125] Accordingly, rather than impose a novel and generic restriction on transmission customers' discretion to schedule transmission service here, without the benefit of broad industry comment, we will allow the mechanisms discussed in Order No. 764 to work and revisit them when and if necessary.

96. Finally, we find Powerex's concerns about e-Tagging to be beyond the scope of this proceeding. Powerex's concern appears to be specific to power being exported from Bonneville's system and the extent to which Bonneville's curtailment practices pursuant to as Dispatcher Standing Order 216 (DSO 216) render certain transactions sufficiently "firm." Ultimately, however, Powerex's concern is more of a commercial matter between the buyer and the seller of power being exported from Bonneville's system. To the extent power is being exported from Bonneville's system, customers and neighboring balancing authorities are aware that Bonneville has implemented DSO 216 and that export transactions are subject to curtailment. It is up to these customers to decide for themselves whether such transactions can be marketed as "firm" or as something else.

97. Moreover, Powerex's concern appears to be based primarily on the firmness of the energy that is scheduled by the e-Tag and not on the firmness of the transmission service. E-Tags only reflect the firmness of transmission service priorities that transmission customers reserved prior to scheduling; they do not reflect the firmness of energy. While certain events (e.g., a forced outage or a curtailment pursuant to DSO 216) could interrupt the flow of energy scheduled by an e-Tag, that does not change the underlying nature of transmission service. Because the Commission's focus here is on the reserves necessary to support transmission service, we decline to require generic revisions to e-Tags here to address the unrelated issue of whether changes to e-Tags are necessary to reflect the potential that energy scheduled by an e-Tag as firm may ultimately not flow. In terms of reliability, transmission providers still have the authority to alleviate capacity and energy emergencies according to applicable reliability standards.[126]

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[125] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 108.

[126] *See, e.g.*, EOP-002-3.1 Capacity and Energy Emergencies (authorizing balancing authorities and reliability coordinator to take whatever actions are needed to ensure the reliability of their respective areas and to alleviate capacity and energy emergencies).

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D. Regulatory Flexibility Act Analysis

1. Order No. 764

98. In Order No. 764, the Commission recognized that "the cost of moving from hourly to 15-minute transmission scheduling could be substantial."[127] The Commission further stated that:

> 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. 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.[128]

99. The Commission noted that many of the costs cited by commenters as being specific to 15-minute scheduling are really related to the automation of systems used to process transmission schedules and verify cross-balancing authority aggregate schedules, which the Commission did not mandate.[129] Furthermore, the Commission acknowledged that some commenters raised concerns about costs associated with sub-hourly settlement of imbalance charges and sub-hourly dispatch of resources, neither of which the Commission required in Order No. 764.[130]

100. The Commission also conducted an analysis under the RFA.[131] The Commission explained that Order No. 764 applies to public utilities that own, control or operate interstate transmission facilities (that have not received waiver of the obligation to comply with Order Nos. 888, 889, and 890) and to variable energy resources. The

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[127] Order No. 764, FERC Stats. & Regs, ¶ 31,331 at P 102.

[128] *Id.* (internal footnote omitted).

[129] *Id.* P 103.

[130] *Id.* P 104.

[131] *Id.* P 384.

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Commission estimated that ten small public utility transmission providers[132] would be affected equally by Order No. 764, at an average cost of $13,500 per year. The Commission found that this was not a significant economic impact, noting that in any event, each of these entities may seek waiver of these requirements.[133] (The Commission also found that Order No. 764 would not have a significant economic impact on VERs, which NRECA does not challenge in its rehearing request.) Accordingly, the Commission certified that Order No. 764 would not have a significant economic impact on a substantial number of small entities.

2. Request for Rehearing

101. NRECA argues that the Commission erred in concluding that Order No. 764 will not have a significant impact on a substantial number of small entities and that, therefore, no final regulatory flexibility analysis is required under the Regulatory Flexibility Act (RFA).[134] Specifically, NRECA objects to the Commission's determination that Order No. 764 will "impact all the applicable transmission providers equally at an annual cost of $13,500 per year."[135]

102. NRECA argues that in response to the Proposed Rule, it provided estimates of the cost impacts of the Commission's intra-hour scheduling reform, explaining that the changes needed to implement the reform will depend on a number of factors, including the size of the transmission provider, whether the transmission provider is an RTO, and the number of customers that take advantage of 15-minute scheduling.[136] On rehearing,

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[132] 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.

[133] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 384 & n.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.").

[134] NRECA at 2 (citing Regulatory Flexibility Act of 1980, 5 U.S.C. §§ 601-612 (2006)).

[135] *Id.* (referencing Order No. 764, FERC Stats. & Regs, ¶ 31,331 at P 384).

[136] *Id.* at 3 (citing NRECA, Comments on Proposed Rule at 10-15).

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NRECA quotes the Commission's description of its cost estimates in response to the Proposed Rule:

> 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 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.[137]

103. NRECA emphasizes that the Commission noted that such costs were "not insignificant" and that the Commission did not question or criticize NRECA's cost estimates.[138] NRECA contrasts these findings with the Commission's RFA analysis, in which the Commission found that Order No. 764 would affect all applicable small transmission providers equally at an average cost of $13,500 per year, and that it will not have a significant economic impact on a substantial number of small entities.[139]

104. NRECA argues that the Commission did not provide any evidence to support the assumption that the average cost impact of Order No. 764 on small transmission providers will be $13,500. Further, NRECA states that the estimates the Commission did cite, and characterized as "not insignificant" and potentially "substantial," are in the range of $1-2 million per year if intra-hour scheduling is widely used. NRECA contends that even if intra-hour scheduling were limited to VERs, NRECA estimated a cost impact of $50,000, which does not take into account $250,000 in annual additional software-related costs that some NRECA members have incurred.[140] NRECA notes that this $50,000 estimate is "nearly quadruple" the Commission estimate of $13,500 per year. For these reasons, NRECA contends that the Commission has not articulated a

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[137] *Id.* at 4 (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 82).

[138] *Id.* (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 102).

[139] *Id.* at 4-5 (referencing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 384).

[140] *Id.* at 5.

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satisfactory explanation for concluding that Order No. 764 will not have a substantial economic impact on a substantial number of small entities.

3. Commission Determination

105. As an initial matter, we note that NRECA challenges only one portion of the Commission's RFA certification—the Commission's finding that the average cost impact on small public utility transmission providers would be $13,500 per year, which the Commission determined was not a significant economic impact.[141] NRECA does not challenge the Commission's finding that Order No. 764 will only affect ten small public utility transmission providers, nor does it challenge the Commission's estimates or its finding that Order No. 764 would not have a significant economic impact on the 160 VERs that the Commission found to be small entities.[142] Moreover, NRECA does not challenge, let alone address, Order No. 764's express acknowledgment that small public utility transmission providers may seek waiver of the Commission's intra-hour scheduling requirement.[143]

106. NRECA's key argument focuses on the Commission's acknowledgement that the costs of implementing the intra-hour scheduling reform *could be* significant, as well as the fact that the Commission did not specifically discredit cost estimates in the range of $1-2 million. Simply because the Commission acknowledged that such costs are "not insignificant," however, does not mean that the Commission accepted $1-2 million estimates as reasonable cost estimates for small public utilities. Indeed, the Commission acknowledged these higher cost estimates in the context of evaluating how the potential costs of the intra-hour scheduling reform measured against the potential benefits for all public utility transmission providers, not just *small* public utility transmission providers. In this context, the Commission found that even if the costs of the reform were on the higher side due to substantial use of intra-hour scheduling by customers, such costs would be justified in light of the significant benefits to customers in the form of reduced

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[141] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 384.

[142] *See id.* (noting that approximately 100 VERs will be required to comply with Order No. 764, whereas 60 VERs will have the option to do so).

[143] *Id. See Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 738 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) (recognizing that the Commission, in the context of an RFA certification, was not insensitive to the potential impact of Order No. 888 on small non-jurisdictional entities, allowing such entities to file for a waiver from compliance with the reciprocity conditions).

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imbalance charges.[144] It bears emphasis that the discussion of potential costs in this section of Order No. 764 was in reference to *all* public utility transmission providers. It is therefore unremarkable that estimated costs for *small* public utility transmission providers, which the Commission discussed elsewhere in Order No. 764, would be different.

107. As the Commission explained in Order No. 764, a principal driver of costs associated with the intra-hour scheduling reform is the number of transmission customers who will request intra-hour schedules.[145] Due to their relative small size, the Commission expects small public utility transmission providers to have fewer customers that take advantage of intra-hour scheduling, and therefore fewer costs. As a result, NRECA's lower $50,000 estimate is more in line with expected costs described in Order No. 764 to the ten public utility transmission providers that qualify as small entities for the complete implementation of the Commission's reforms, and the higher estimates (in the $1-2 million range) are unlikely, as explained in Order No. 764 and clarified here.[146]

108. The Commission based the $13,500 estimate on the cost per small public utility transmission provider as described in the information collection statement in Order No. 764.[147] Specifically, the Commission estimated 118 hours of burden for each transmission provider. The Commission applied a $114 per hour average wage[148] to the burden hour to arrive at the $13,500 estimate (118 hours * $114 per hour = $13,452). The Commission believes that such costs are an accurate representation of both the staffing and software costs associated with the reforms required by Order No. 764. Additionally, the Commission estimate of $13,500 per year is based on the expected cost

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[144] *Id.* P 102.

[145] *Id.*

[146] NRECA itself acknowledged in its comments on the Proposed Rule that the costs of intra-hour scheduling should be manageable, stating that "NRECA expects that in some cases, there will be significant costs needed to implement this reform. But NRECA believes the costs will not be extraordinary, and that these costs can and should be mitigated through proper design and implementation." NRECA, Comments on Proposed Rule at 11.

[147] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 381.

[148] $114 per hour represents the average cost of an attorney ($200 per hour), consultant ($150 per hour), technical ($80 per hour), and administrative support ($25 per hour).

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over the first three years of compliance with Order No. 764, whereas the NRECA estimate of $50,000 is characterized as "limited to upfront software modifications."[149] Accordingly, we interpret NRECA's $50,000 estimate as related to a single investment rather than recurring yearly costs. With that in mind, considering the full three-year Commission estimate of $40,500 ($13,500 multiplied by three years), the Commission estimate is not much different from NRECA's estimate of $50,000.

109. Finally, even if the Commission were to consider NRECA's software cost estimate as not included in the estimate described in Order No. 764, we nonetheless find that the combined Commission and NRECA cost estimates (the $40,500 Commission three-year estimate plus the $50,000 NRECA software cost estimate) would still not be a significant burden on small entities. The annual cost of these combined estimates would be approximately $30,200 per year ($90,500 divided by 3 years). The Commission would not consider this $30,200 per year estimate to be a significant economic burden on small public utility transmission providers. Therefore, even if the Commission were to accept a burden estimate nearly double NRECA's estimate, the Commission still would not be required to perform a final regulatory flexibility analysis under the RFA.

110. Accordingly, the Commission affirms Order No. 764's conclusion that costs of that rule do not represent a significant economic impact on a substantial number of small entities.[150]

The Commission orders:

(A) Requests for clarification and rehearing are granted or denied, as discussed in the body of this order.

(B) The deadline for compliance with Order No. 764 is hereby extended to November 12, 2013.

By the Commission. Commissioner Clark is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[149] NRECA, Comments on Proposed Rule at 12.

[150] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 384.

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141 FERC ¶ 61,242
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.

North American Electric Reliability Corporation Docket No. NP11-238-001

ORDER DENYING REHEARING

(Issued December 20, 2012)

1. On July 19, 2012, the Commission issued an order[1] finding that section 215 of the Federal Power Act (FPA)[2] authorizes the imposition of a monetary penalty on a federal entity that violates a mandatory Reliability Standard, and affirming the North American Electric Reliability Corporation's (NERC's) imposition of a $19,500 penalty against the Southwestern Power Administration (SWPA). Several entities, including SWPA, jointly with the U.S. Department of Energy (DOE), and the Department of the Interior (Interior), submitted requests for rehearing of the July 2012 Order, asserting that the Commission erred in (1) finding that sovereign immunity had been waived with respect to the imposition of a monetary penalty against a federal entity such as SWPA; (2) departing from established Commission precedent finding that FPA section 316A, which addresses the imposition of civil penalties for violations of Part II of the FPA, is applicable to FPA section 215; and (3) construing the enforcement authorities of FPA section 215 in a manner that frustrates other congressionally-established policies under the Flood Control Act and the Anti-Deficiency Act.

2. We hereby deny the requests for rehearing and affirm our prior ruling finding that FPA section 215 authorizes the imposition of a monetary penalty on federal entities found to be in violation of a mandatory Reliability Standard.

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[1] *North American Electric Reliability Corp.*, 140 FERC ¶ 61,048 (2012) (July 2012 Order).

[2] 16 U.S.C. §824o (2006).

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I. Background

A. Statutory Framework

3. Section 215 of the FPA authorizes the Commission to certify and oversee an electric reliability organization (ERO) responsible for the development and enforcement of mandatory Reliability Standards applicable to users, owners and operators of the Bulk-Power System.[3] Exercising this statutory authority, the Commission certified NERC as the ERO in 2006,[4] and has since approved over one hundred national Reliability Standards as mandatory and enforceable, pursuant to FPA section 215(d).[5] As contemplated under FPA section 215(e)(4), NERC has delegated certain oversight and enforcement authority to eight Regional Entities,[6] including the Southwest Power Pool Regional Entity (SPP Regional Entity), which has enforcement and oversight responsibility for SWPA.

4. Section 215(b)(1) of the FPA, titled "Jurisdiction and Applicability," describes the Commission's reliability jurisdiction as follows:

> The Commission shall have jurisdiction . . . over . . . all users, owners and operators of the bulk-power system, *including but not limited to the entities described in section 201(f),* for purposes of approving reliability standards established under this section *and enforcing compliance* with [FPA section 215]. All users, owners and operators of the

[3] 16 U.S.C. § 824o(c).

[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 ¶ 61,190, *order on reh'g* 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[5] 16 U.S.C. § 824o(d); *see, e.g., Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. and Regs. ¶ 31,242, *order or reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[6] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

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> bulk-power system shall comply with reliability standards that take effect under this section.[7]

Section 201(f) of the FPA, in turn, provides that Part II of the FPA (which includes section 215) does not apply to federal agencies, among other entities, except where a particular provision makes an exception:

> No provision in [Part II of the FPA] shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, . . . or any agency, authority, or instrumentality of any one or more of the foregoing . . . *unless such provision makes specific reference thereto*.[8]

5. NERC and the Regional Entities to which NERC delegated compliance and enforcement authority identify potential violations using various compliance tools, including audits, spot checks, investigations, required self-certifications, and voluntary self-reporting. If a violation is found, NERC has authority pursuant to FPA section 215(e)(1) to impose a penalty on the user, owner or operator of the Bulk-Power System found to be in violation, subject to certain due process and review requirements.[9]

6. Under the statute and its implementing regulations, NERC must file a Notice of Penalty with the Commission before an assessed penalty can take effect.[10] Each such penalty determination is subject to Commission review, either on its own motion or by application for review by the recipient of a penalty, within thirty days from the date NERC files the applicable Notice of Penalty.[11] In the absence of an application for

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[7] 16 U.S.C. § 824o(b)(1) (emphasis added).

[8] 16 U.S.C. § 824(f) (emphasis added).

[9] 16 U.S.C. § 824o(e)(1).

[10] 16 U.S.C. § 824o(e)(1) and (2); *see also 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, at P 506, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[11] 16 U.S.C. § 824o(e)(2).

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review of a penalty or other action by the Commission, each penalty filed by NERC is affirmed by operation of law upon the expiration of the applicable thirty-day period.[12]

B. SWPA Violations and NERC Notice of Penalty Filing

7. As noted in the July 2012 Order, SWPA is a subdivision of DOE, operating under the authority of section 5 of the Flood Control Act of 1944 (Flood Control Act). SWPA is one of four federal Power Marketing Administrations, and markets hydroelectric power from 24 Army Corps of Engineers projects in the Southwest United States, primarily to defined "preference" customers including rural electric cooperatives and municipal utilities. SWPA operates and maintains 1,380 miles of high-voltage transmission lines in a four-state area located within the region for which the SPP Regional Entity has reliability oversight.[13] SWPA is registered in NERC's Compliance Registry as a balancing authority, purchasing-selling entity, resource planner, transmission owner, transmission operator, transmission planner and transmission service provider[14] and, as such, is required to comply with all Commission-approved Reliability Standards applicable to such entities.[15]

8. In 2009, SWPA self-reported certain violations of NERC's approved Critical Infrastructure Protection or "CIP" Reliability Standards, and the SPP Regional Entity subsequently identified additional violations of those standards during a spot check.[16] The SPP Regional Entity proposed a penalty of $19,500 in total for the violations, which NERC ultimately affirmed over SWPA's objection. Notably, SWPA did not dispute the

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[12] *Id.*; *see also* 18 C.F.R. § 39.7(e)(1) (2012).

[13] *See* July 2012 Order, 140 FERC ¶ 61,048 at P 9; *see also* NERC Notice of Penalty at 1, n.1.

[14] *See* NERC Rules of Procedure Section 500 – Organization Registration and Certification.

[15] The particular Reliability Standards at issue here, CIP-004-1 and CIP-007-1, are applicable to SWPA as a registered balancing authority and transmission operator.

[16] *See* NERC Notice of Penalty at 2-10. Reliability Standard CIP-004-1 sets out requirements for personnel who have authorized cyber access or authorized unescorted physical access to Critical Cyber Assets, including requirements related to personnel risk assessment, training, and security (including cyber security). CIP-007-1 sets out requirements related to security systems determined to be Critical Cyber Assets and other assets within an "Electronic Security Perimeter."

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underlying facts related to the violations or the amount of the proposed penalty. Instead, SWPA contested the penalty before NERC based on the claim that federal entities are not subject to monetary penalties for Reliability Standard violations because FPA section 316A, which sets out the Commission's general civil penalty authority, does not extend to federal entities.[17]

9. NERC filed the SWPA Notice of Penalty with the Commission on July 28, 2011, and included a detailed discussion of the procedural history associated with the violations, as well as NERC's analysis of the scope of its penalty authority under FPA section 215. SWPA, in a joint filing with DOE, made a timely request for Commission review of NERC's assessed penalty, on similar legal grounds as were argued before NERC, i.e., that FPA section 316A does not permit the imposition of civil penalties on a federal agency (because such penalties can only be imposed on "persons," defined as an individual or a corporation), that FPA section 215 is not an independent source of authority to impose penalties, or that, at a minimum, the FPA does not reflect a sufficiently clear statement of congressional intent to waive sovereign immunity. A number of entities intervened, making similar arguments to those of SWPA and DOE, including Interior and various associations of wholesale customer groups who purchase power from SWPA and other similar federal power marketing entities.

C. July 2012 Order

10. In the July 2012 Order, the Commission held that the grant of authority to impose a penalty on any user, owner, or operator of the Bulk-Power System that violates a mandatory Reliability Standard, including federal entities, is explicit and unambiguous. The Commission reviewed and relied on the plain language of FPA section 215, first noting that section 215(b) states that the Commission has jurisdiction over all users, owners, and operators of the bulk-power system "*including but not limited to the entities described in section 201(f)*, for purposes of approving reliability standards established under this section *and enforcing compliance with this section*."[18] The Commission then noted that enforcement of FPA section 215 is governed by subsection 215(e), which authorizes the imposition of a penalty by the ERO under (e)(1) and (e)(2), and by the

[17] FPA section 316A states in relevant part that "[a]ny person who violates any provision of part II or any provision of any rule or order thereunder shall be subject to a civil penalty of not more than $1,000,000 for each day that such violation continues." 16 U.S.C. § 825o-1(b).

[18] July 2012 Order, 140 FERC ¶ 61,048 at P 39 (quoting 16 U.S.C. § 824o(b)(1) (emphasis supplied in order, emphasis added to the statute).

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Commission under (e)(3).[19] The Commission held that these grants of authority to the ERO and to the Commission are unambiguous and unequivocal, and as such are sufficient to act as a waiver of sovereign immunity with respect to federal entities found to be in violation of a mandatory Reliability Standard.[20]

11. The Commission further found that FPA section 316A does not alter this explicit grant of authority under FPA section 215 or otherwise render it ambiguous.[21] The Commission rejected the arguments of DOE/SWPA that the authority to impose a monetary penalty for violations of a Reliability Standard derives from FPA section 316A and not from FPA section 215, including their claim that FPA section 215(e) merely sets out procedural requirements and does not act as an independent grant of penalty authority.[22] In addition, the Commission rejected the notion that its prior findings on the applicability of the monetary cap set out in FPA section 316A to penalties imposed under FPA section 215 suggest that FPA section 316A is the source of the Commission's FPA section 215 penalty authority.[23]

12. The Commission specifically addressed whether the grant of authority to impose a monetary penalty on federal entities under FPA section 215 was sufficiently clear and unequivocal to serve as a waiver of sovereign immunity.[24] The Commission concluded that regardless of which standard of clarity is used to test whether sovereign immunity has been waived,[25] the language of FPA section 215 is sufficiently explicit to find such a waiver.

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[19] *Id.* P 40.

[20] *Id.* P 42.

[21] *See id.* PP 42-53.

[22] *Id.* PP 45-48.

[23] *Id.* P 49.

[24] *Id.* P 53.

[25] *See id.* P 53 & n.72 (noting that the standard for imposition of a penalty on a federal entity by another federal agency is arguably less rigorous than the standard applicable to private suits, and only requires a "clear statement" of congressional intent to authorize the imposition of a penalty). Despite the likely applicability of this standard, the Commission found that "the requirements for waiver are met using the highest level of scrutiny, i.e., that waiver has been clearly and unambiguously expressed in the statutory text." *Id.* n.72.

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13. The Commission also rejected various policy-based arguments for interpreting its (and NERC's) section 215 penalty authority more narrowly, first noting the detrimental impact on electric system reliability of exempting such a large class of registered entities from section 215's reliability regime. The Commission rejected arguments that the imposition of penalties on federal entities such as SWPA would not provide a meaningful incentive for future compliance, regardless of the potential for passing such costs on to customers or recovering them from taxpayers, given the expectation of congressional and customer scrutiny if such entities continue to incur significant FPA section 215 penalties.[26] The Commission found no inconsistency with the Flood Control Act in imposing monetary penalties on federal entities like SWPA.[27] Finally, the Commission found no discernible conflict with the Anti-Deficiency Act, given that payment of such an administratively imposed civil penalty is permissible as a "necessary expense" where sovereign immunity has been waived.[28]

D. Requests for Rehearing

14. Timely requests for rehearing were filed by DOE and SWPA jointly (DOE/SWPA), Interior, the Mid-West Electric Consumers Association and the Southwestern Power Resources Association (Mid-West ECA), and the Southeastern Federal Power Customers, Inc. (SE FPC). DOE/SWPA and Interior also included a motion for stay of the SWPA penalty while the requests for rehearing were pending.

15. All of the entities seeking rehearing make arguments based on the doctrine of sovereign immunity, alleging that the Commission erred in both its reading of the language of FPA section 215 and in its analysis of the impact of FPA section 316A on the authority to impose monetary penalties on federal entities found in violation of a mandatory Reliability Standard. With respect to the applicable standard for determining whether sovereign immunity has been waived, DOE/SWPA, Interior, and SE FPC maintain that any such waiver must be "unequivocally expressed" in the statutory text.[29]

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[26] *Id.* P 56.

[27] *Id.* P 57.

[28] *Id.* PP 58-60.

[29] *See* DOE/SWPA Rehearing Request at 4 (citing *Lane v. Pena*, 518 U.S. 187 (1996) (*Lane v. Pena*), *United States Dep't of Energy v. Ohio,* 503 U.S. 607 (1992) (*DOE v. Ohio*); and *United States v. Nordic Village, Inc.,* 503 U.S. 30 (1992) (*Nordic Village*), among others, for the proposition that a waiver of the federal government's sovereign immunity must be unequivocally expressed in statutory text); *see also* Interior Rehearing Request at 3; SE FPC Rehearing Request at 10.

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These entities also assert that under this strict standard of interpretation, ambiguities must be construed in favor of immunity, and that ambiguity exists if "there is a plausible interpretation of the statute that would not authorize money damages against the Government."[30] Moreover, these entities assert that any ambiguities with respect to the *scope* of the waiver must be construed in favor of the governmental entity, and that "any waiver of sovereign immunity that would authorize payments from the federal treasury 'must extend unambiguously to such monetary claims.'"[31]

16. DOE/SWPA and Interior argue that the sub-sections of FPA section 215 on which the Commission relies in the July 2012 Order do not contain the kind of explicit language needed to support an unequivocal and unambiguous waiver of sovereign immunity.[32] First, they note that FPA section 215(b) does not grant any enforcement or penalty powers to the ERO.[33] While they acknowledge that FPA section 215(b) makes federal agencies subject to the Commission's jurisdiction for purposes of "enforcing compliance" with FPA section 215, they argue that the provision does not speak to *how* the Commission can enforce compliance and note that it does not explicitly state that such enforcement can include "retrospective monetary penalties."[34] In support of this position, DOE/SWPA maintain that the phrase "enforce compliance" is used elsewhere in the FPA

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[30] DOE/SWPA Rehearing Request at 4 (citing *Federal Aviation Admin. v. Cooper*, 132 S. Ct. 1441, 1448 (2012) and quoting *Nordic Village*, 503 U.S. at 34, 37); *see also* Interior at 4.

[31] Interior Rehearing Request at 4 (quoting *Lane v. Pena*, 518 U.S. at 192); DOE/SWPA Rehearing Request at 4. According to SE FPC, the case law on sovereign immunity requires that the following three elements be met: (1) waiver must be part of the statutory text; (2) waiver cannot be implied; and (3) waiver must explicitly reference monetary claims. SE FPC Rehearing Request at 11. SE FPC further maintains that this line of cases requires that the statutory language must specifically reference the federal government and must include "language delineating a waiver such as 'notwithstanding any immunity.'" *Id.* at 13.

[32] DOE/SWPA Rehearing Request at 5-6; *see also* Interior Rehearing Request at 5-6 (asserting that the statute does not clearly indicate that federal entities are subject to monetary penalties, as is necessary to effectuate a waiver of sovereign immunity), SE FPC Rehearing Request at 8-10.

[33] *See* DOE/SWPA Rehearing Request at 6.

[34] *Id.* at 7; *see also* SE FPC Rehearing Request at 8.

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to mean actions other than the imposition of penalties, citing FPA section 201(g) and FPA section 314(a).[35]

17. DOE/SWPA argue that FPA section 215(e) also lacks the specificity needed to effectuate a waiver of sovereign immunity because it does not state that the penalties it authorizes can be monetary in nature.[36] DOE/SWPA argue that FPA section 215(e) does not "expressly apply to the federal government," and that section 215(b) "only makes federal entities subject to the Commission's jurisdiction for purposes of 'enforcing compliance' and does not mention exposing federal entities to penalties, much less monetary penalties."[37] For all of these reasons, these entities claim that they have advanced a plausible interpretation of FPA section 215 that does not permit the imposition of penalties on federal entities.[38]

18. In the alternative, DOE/SWPA and Interior argue that no waiver of sovereign immunity can be found when FPA section 215 is read in concert with FPA section 316A. Interior explains that FPA section 316A does not authorize civil penalties against federal entities, because they do not meet the FPA's definition of "person," and that this provision therefore creates sufficient ambiguity to find no waiver of sovereign immunity under FPA section 215.[39] These entities also assert that FPA section 215 cannot be read as a separate grant of penalty authority, because FPA section 215 does not bear any "indicia" of a grant of such authority. Specifically, DOE/SWPA note that FPA section 215 does not specify what penalties may be imposed, does not contain quantitative limits, and does not specify a mechanism for judicial enforcement.[40]

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[35] DOE/SWPA Rehearing Request at 8.

[36] *Id.* at 9-10 (citing *Maine v. Dep't of Navy*, 973 F.2d 1007, 1011 (1st Cir. 1992) and *DOE v. Ohio*, 503 U.S. at 621, for the proposition that a lack of specificity as to the kind of penalty authorized equates to a failure to unequivocally and unambiguously waive immunity). *See also* Interior Rehearing Request at 5 ("Section 215 does not elaborate on the meaning of 'penalty,' nor does it expressly state that monetary penalties are permissible.").

[37] DOE/SWPA Rehearing Request at 11.

[38] *See id.*

[39] Interior Rehearing Request at 6-8.

[40] DOE/SWPA Rehearing Request at 12-13.

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19. DOE/SWPA and Interior also argue that the Commission's findings in the July 2012 Order contradict its prior findings in Order No. 672, in which the Commission held that "Section 316A of the FPA establishes a limit on a monetary penalty for a violation of a Reliability Standard pursuant to FPA Section 215."[41] According to DOE/SPWA, logic dictates that if FPA section 215 is a separate grant of penalty authority then it should not be limited by FPA section 316A at all. If that is not the case, and the two provisions are instead to be read together, then DOE/SWPA maintain that "all of Section 316A's provisions apply to monetary penalties under Section 215."[42] DOE/SWPA further argue that "[i]f section 316A governs the size of monetary penalties under Section 215, it must also govern which entities may be forced to pay."[43]

20. Mid-West ECA and SE FPC make many of the same, or similar, arguments to that of DOE/SWPA in support of their requests for rehearing. Mid-West ECA asserts that the Commission failed to explain its departure from established precedent interpreting FPA section 316A as establishing limits on monetary penalties for violations under FPA section 215.[44] Mid-West ECA argues that the Commission's prior rulings, in Order No. 672 and elsewhere, "demonstrate that Section 316A is the source of 'empowerment' for the Commission's and NERC's authority to impose a penalty" under FPA section 215.[45]

21. Similarly, Mid-West ECA asserts that the Commission failed to consider the FPA in its entirety when assessing the Commission's authority under FPA section 215, maintaining that the Commission's only explicit authority to impose monetary penalties is contained in FPA section 316A.[46] Mid-West ECA argues that FPA section 215 fails to meet the standard required for a waiver of sovereign immunity as set out in *Lane v. Pena*

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[41] *Id.* at 14 (quoting Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 575).

[42] *Id.* at 14-15.

[43] *Id.* at 15.

[44] Mid-West ECA Rehearing Request at 7-13.

[45] *Id.* at 9. Mid-West ECA also notes that the Commission "has consistently described the impact of Section 316A on Section 215 as 'establishing' and 'setting' rather than guiding," thereby demonstrating that Section 215 does not provide an independent source of penalty authority. *Id.* at 10.

[46] *Id.* at 15-16.

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and *DOE v. Ohio, et al.*,[47] but also maintains that FPA section 215 does not even qualify as a "clear statement" of congressional intent to subject federal agencies to penalty authority.[48] Mid-West ECA asserts that if Congress had intended to make federal entities subject to penalties under the FPA, it could have amended FPA section 316A to do so.[49] Similarly, Mid-West ECA suggests that Congress would have revised the language of FPA section 201(b)(2), where it lists the FPA provisions applicable to section 201(f) entities, to include FPA section 316A if it had intended to waive immunity for FPA section 215 violations.[50]

22. Mid-West ECA also relies on a number of policy arguments in seeking rehearing of the July 2012 Order, claiming that the Commission's reading of FPA section 215 frustrates congressional intent under other statutes or leads to inconsistencies in the Commission's own policies.[51] First, Mid-West ECA argues that the imposition of a penalty on a federal agency will not provide an incentive to proactively comply with Reliability Standards, because the penalty costs may be readily passed through to customers or covered by taxpayers through appropriations.[52] Mid-West ECA likens this situation to that of RTOs and ISOs, where the Commission has recognized that the ready availability of such pass-through mechanisms can weaken compliance incentives.[53]

23. Mid-West ECA also asserts that the imposition of penalties on federal agencies, which then pass those costs on to preference customers, would frustrate the intent of the Flood Control Act and its encouragement of the distribution of power and energy to preference customers at "the lowest possible rates to consumers consistent with sound business principles."[54] Mid-West ECA asserts that the July 2012 Order incorrectly characterizes the congressional mandate of the Flood Control Act, and that any imposition of a monetary penalty on a covered federal entity is inconsistent with the

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[47] *Id.* at 22-25.

[48] *Id.* at 19-22.

[49] *Id.* at 20.

[50] *Id.* at 21.

[51] *See id.* at 25-32.

[52] *Id.* at 25-27.

[53] *Id.* at 26.

[54] *Id.* at 28 (quoting section 5 of the Flood Control Act, 16 U.S.C. § 825s (2006)).

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Flood Control Act's directive to provide preference customers access to power at the "lowest possible price."[55]

24. Finally, Mid-West ECA and SE FPC argue that the Commission did not properly consider the potential conflict between its interpretation of FPA section 215 and the Anti-Deficiency Act,[56] asserting, *inter alia*, that payment of a penalty by a federal agency or federal officer could run afoul of the Anti-Deficiency Act if there is no clear waiver of sovereign immunity.[57] Mid-West ECA maintains that the Commission must consider and make a determination regarding all applicable statutory and appropriations authorities to assess whether a penalty payment by a specific federal entity is precluded by the Anti-Deficiency Act.[58] Mid-West ECA argues that the Commission failed to make these kinds of careful determinations regarding how penalty amounts can or should be paid, and otherwise to fully consider the potential conflicts under the Anti-Deficiency Act.[59]

25. Finally, DOE/SWPA and Interior include a motion for stay of the penalty against SWPA pending resolution of the rehearing requests, with DOE/SWPA noting the Commission's general policy of staying penalties under Commission review.[60] DOE/SWPA assert that a stay would prevent wasted government resources, particularly with respect to the pursuit of other penalty cases now pending before the Regional Entities.[61]

II. Discussion

26. We find, as we did in the underlying July 2012 order, that FPA section 215 unequivocally and unambiguously authorizes the imposition of monetary penalties on

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[55] *Id.* at 29.

[56] 31 U.S.C. § 1341 (2006).

[57] Mid-West ECA Rehearing Request at 30; SE FPC Rehearing Request at 17-18.

[58] Mid-West ECA Rehearing Request at 31.

[59] *Id.* at 32.

[60] DOE/SWPA Rehearing Request at 17 (citing *Statement of Administrative Policy on Processing Reliability Notices of Penalty and Order Revising Statement in Order No. 672*, 123 FERC ¶ 61,046 at P 12 (2008)); *see also* Interior Rehearing Request at 9-10.

[61] DOE/SWPA Rehearing Request at 18; Interior Rehearing Request at 9.

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federal entities that are found to be in violation of a mandatory Reliability Standard. We reach that conclusion based on the explicit language of FPA section 215 in context and in its entirety, and we do not agree that the section can plausibly be interpreted as a grant of enforcement authority over federal entities that are users, owners, or operators of the Bulk-Power System for reliability-related purposes *other* than the imposition of monetary penalties, as the entities seeking rehearing maintain.[62]

27. We further find that no ambiguity arises as a result of the Commission's arguably more limited authority to impose a monetary penalty on a federal entity under FPA section 316A, and reject the notion that FPA section 215 does not serve as an independent source of authority to impose a monetary penalty. Nor do we agree that our findings with respect to such independent authority represents a departure from our prior rulings regarding the applicability of FPA section 316A's monetary cap to FPA section 215 penalties. As we found in the underlying order, our decision to allow the application of such monetary caps to FPA section 215 in no way suggested that any other limitations of FPA section 316A should supplant the plain language of FPA section 215 with respect to scope.

28. We reject arguments that the grant of enforcement authority under FPA section 215 is limited by the scope of the Commission's general civil penalty authority over federal entities, as set out in FPA section 316A, and instead find that the separate grant of penalty authority over federal entities under FPA section 215 is explicit and unambiguous. Accordingly, we find that the ERO, as well as the Commission, is imbued with the penalty authority granted under FPA section 215(e).

29. As in our underlying order, we find no policy basis for exempting federal agencies from the assessment of monetary penalties under section 215. While we acknowledge that federal agencies may not share the *same* incentive systems as privately-owned users, owners and operators of the Bulk-Power System, we believe that the imposition of penalties still acts as a significant incentive for future compliance. Finally, we again find no inconsistency with the Anti-Deficiency Act.

A. FPA Section 215 is Unequivocal and Unambiguous in Authorizing the Imposition of Monetary Penalties on Federal Entities

30. In the July 2012 Order, we found that the plain language of FPA section 215 explicitly conveys authority to assess a monetary penalty against a federal entity for violations of a mandatory Reliability Standard. We did so through an examination of the

[62] Given our findings in this Order Denying Rehearing, we dismiss as moot the motions for stay of the $19,500 penalty against SWPA.

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specific statutory language of FPA section 215 (and the applicable definitional sections of the FPA), without recourse to any underlying policy objectives or legislative history, as some of the entities have suggested.[63] Nor did we rely on assumptions or implication in our analysis of FPA section 215. Rather, we considered the plain meaning of the statutory text, in the context of, and with reference to, the entirety of FPA section 215 and the rest of the FPA.

31. In the July 2012 Order, we explained that FPA section 215(b) defines the jurisdictional scope of FPA section 215 as extending to all users, owners and operators of the Bulk-Power System, "including but not limited to the entities described in section 201(f) for purposes of approving reliability standards under this section *and enforcing compliance with this section.*"[64] We further explained that SWPA is an FPA section 201(f) entity and is a user, owner or operator of the Bulk-Power System.[65] Finally, we found that enforcement of compliance under FPA section 215 is covered under subsection 215(e), which explicitly includes the option of imposing a penalty on any user, owner or operator of the Bulk-Power System found to be in violation of a mandatory Reliability Standard.[66]

32. Notably, we reached our conclusion regarding the scope of FPA section 215's penalty authority using the same strict standards of statutory construction that DOE/SWPA and other entities claim is required in order to find a waiver of immunity,

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[63] *See, e.g.,* SE FPC Rehearing Request at 15 (stating that "[t]he Commission's reliance on arguments presented by NERC and its reference to the legislative history are equally unavailing to support a finding of a waiver of sovereign immunity" and citing to the July 2012 Order, 140 FERC ¶ 61,048 at P 14). Notably, SE FPC cites to a paragraph in our background discussion of the history of the case, not to findings or arguments made in the substantive sections of the order. Similarly, while Mid-West ECA correctly remarks that the July 2012 Order noted the potentially large regulatory gap if federal entities are not subject to penalties under FPA section 215 (*see* Mid-West ECA Rehearing Request at 24), we did so as part of our analysis of the policy arguments put forward *by commenters* in favor of our declining to impose penalties on federal entities and not as part of our statutory analysis regarding the clarity of the immunity waiver under FPA section 215.

[64] *See* July 2012 Order, 140 FERC ¶ 61,048 at P 39 (quoting 16 U.S.C. § 824o(b)(1) (emphasis added)).

[65] *Id.*

[66] *Id.* P 40.

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i.e., that waiver "must be unequivocally expressed in statutory text and will not be implied."[67] Although we noted in our July 2012 Order that a less rigorous standard might be more applicable in this kind of case, involving the imposition of a penalty on a federal entity for violations of a federal statute, we found the language of FPA section 215 to be sufficiently clear to meet the highest level of scrutiny.[68]

33. As described above, DOE/SWPA and other entities seeking rehearing maintain that, under this strict standard for finding a waiver, any ambiguity must be resolved in favor of the government and that there can be no waiver if there is *any plausible* interpretation of the statute that would not authorize a monetary penalty on federal entities. These entities then argue for an interpretation of FPA section 215 that is *implausible* and requires that each subsection be considered without reference to any other subsection or the applicable definitional provisions of the FPA.

34. DOE/SWPA and other entities acknowledge that federal agencies "are subject to the Commission's jurisdiction 'for purposes . . . of enforcing compliance'" under FPA section 215(b).[69] However, they argue that the phrase "enforcing compliance" in FPA

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[67] *Id.* P 53, n.72.

[68] *Id.* As we stated in the July 2012 Order, a "less rigorous standard has been applied in cases involving the imposition of a penalty by one federal agency on another, i.e., whether there is a 'clear statement' of congressional intent to authorize the imposition of such a penalty against a federal entity or agency" (citing two opinions from the Office of Legal Counsel (OLC), *EPA Assessment of Penalties Against Federal Agencies for Violation of the Underground Storage Tank Requirements of the Resource Conversation and Recovery Act*, 2000 OLC LEXIS 20 (2000) (OLC RCRA Opinion) and *Administrative Assessment of Civil Penalties Against Federal Agencies Under the Clean Air Act*, 1997 OLC LEXIS 29, *slip op.* at 15-16 (1997) (OLC Clean Air Act Opinion)).

Notably, in the OLC RCRA Opinion, the OLC relied on both the plain text of the statute *and* its legislative history in finding a sufficiently clear statement of congressional intent to authorize the assessment of penalties against federal agencies for violations of RCRA's underground storage tank requirements. 2000 OLC LEXIS 20 at 6, n.3. Similarly, in the OLC Clean Air Act Opinion, the OLC relied on changes in the text of the Clean Air Act and House Reports explaining the reason for the change, as well as the plain text of the statute, in finding that "Congress clearly indicated . . . its intent to authorize EPA to use its section 113 enforcement authorities [including civil penalty authority] against federal agencies." 1997 OLC LEXIS 29 at 10-15.

[69] DOE/SWPA Rehearing Request at 7.

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section 215(b) lacks the specificity necessary to constitute a waiver and that the Commission's reading of that term "greatly expands" on how the term is used elsewhere in the FPA.[70] This line of reasoning might have some merit (albeit limited) if there were no specific language elsewhere in FPA section 215 to explain the intended scope of enforcement authority. However, that is not the case, and any plausible interpretation of FPA section 215 must include a consideration of *all* relevant subsections. Thus, when FPA section 215(b) is read in conjunction with FPA section 215(e), we found that FPA section 215 *explicitly* contemplates the imposition of penalties by either the ERO or the Commission.[71]

35. DOE/SWPA and other entities requesting rehearing seek to avoid this result by arguing that (1) use of the word "penalty" in FPA section 215(e) is not explicit enough to allow the imposition of a monetary penalty or fine; and/or (2) FPA section 215(e) does not explicitly refer back to FPA section 201(f) entities (or to federal entities), and therefore cannot effectuate a waiver of immunity.

36. With respect to the first argument, DOE/SWPA and others fail to cite a single sovereign immunity case in which the word "penalty" was found to be insufficiently explicit to allow the imposition of a monetary penalty, nor is that term commonly understood to exclude a monetary fine. Indeed, the very provision of the FPA that these same entities point to as an example of a clear grant of authority to impose a monetary fine, FPA section 316A, uses the terms "penalty" and "civil penalty" but does not use the word "monetary."

37. SE FPC, in particular, overstates what is required under the caselaw to find that a monetary penalty can be imposed on a federal entity, asserting that the waiver of sovereign immunity "must explicitly reference monetary claims."[72] However, SE FPC's own example of statutory language sufficient to authorize the imposition of a monetary penalty on a federal agency demonstrates the fallacy of its argument. SE FPC sets out the following provision from the revised Resource Conservation and Recovery Act (RCRA), as an example of the kind of language necessary to effectuate a waiver of immunity that extends to a monetary fine:

> The United States hereby expressly waives any immunity otherwise applicable to the United States with respect to any

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[70] *Id.*

[71] July 2012 Order, 140 FERC ¶ 61,048 at P 37.

[72] *See* SE FPC Rehearing Request at 11.

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> such substantive or procedural requirement (including, but not limited to, any injunctive relief, administrative relief, administrative order or *civil or administrative penalty* or fine referred to in the preceding sentence, or reasonable service charge).[73]

Notably, this statutory provision, like 215(e)(1) and (e)(3), uses the word "penalty" to include a monetary penalty, without the explicit use of the word "monetary," "monetary claim," or "monetary damages."

38. Thus, contrary to the assertions of the entities seeking rehearing, the courts have not been overly concerned with the use of the term "monetary damage" or "monetary claim" in cases involving the imposition of penalties on a federal entity that violates a federal statute, as opposed to a private suit for damages.[74] As one example, the court in

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[73] SE FPC Rehearing Request at 12-13 (quoting from 42 U.S.C. § 6961, and explaining that the revised language was developed "in the wake of the *U.S. Department of Energy v. Ohio* decision," when "Congress passed the Federal Facilities Compliance Act of 1992 to clarify the scope of the sovereign immunity that was waived under [RCRA]"). *See also U.S. v. Colorado*, 990 F.2d 1565, 1569-70 at n.4 (10th Cir. 1993) (noting that Congress amended RCRA after the Court's decision in *DOE v. Ohio* to clearly provide that federal agencies are not immune from penalties thereunder).

SE FPC also argues that the failure to use explicit immunity "waiver" language (such as "notwithstanding any immunity") must be construed to mean no waiver was intended, but provides no support for that position other than to provide examples of cases in which such language happened to be part of the relevant statute. In fact, courts have found a waiver of sovereign immunity where the statute did not include language stating that "The United States hereby expressly waives any immunity . . . ." *E.g., U.S. v. Tennessee Air Pollution Control Board*, 185 F.3d 529 (6th Cir. 1999) (holding that the Clean Air Act's "state suit" provision, which empowers states to bring enforcement actions against the United States and to obtain administrative remedies or sanctions in the same manner as nongovernmental entities but does not include an express statement of waiver of sovereign immunity, is sufficient to allow the imposition of a $2,500 civil penalty on the U.S. Army).

[74] *See, e.g., Cudjoe v. Dept. of Veterans Affairs*, 426 F.3d 241 (3d Cir. 2005) (finding no waiver of immunity for private suits for money damages for failure to disclose lead paint contamination under the Toxic Substances Act, while noting the statute's express waiver of immunity with respect to EPA enforcement, including the imposition of fines and penalties). In making this distinction, the Court in *Cudjoe*

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U.S. v. Tennessee Air Pollution Control Bd.[75] found that the Clean Air Act "unequivocally and unambiguously" effects a waiver of sovereign immunity that extends to the imposition of penalties for past violations of air quality standards. The court relied on the following savings clause in making that determination, with no apparent concern about its lack of the use of the word "monetary":

> Nothing in this section or in any law of the United States shall be construed to prohibit . . . any State . . . from . . . bringing any administrative enforcement action or obtaining any administrative remedy or sanction in any State or local administrative agency . . . against the United States . . . .[76]

39. We further reject DOE/SWPA's claim that the use of the phrase "enforce compliance" in FPA sections 201(g) and 314(a) has any relevance to the proper interpretation of FPA section 215. FPA section 201(g) and 314(a) both relate to the enforcement authorities of the U.S. districts courts, in the former case giving the district courts authority to enforce compliance with any state commission order to examine the books and accounts of certain jurisdictional entities, and in the latter case to enforce compliance or to enjoin acts or practices that could constitute a violation of the FPA. The use of the term "enforce compliance" in those sections is simply not comparable to that of section 215, particularly when FPA section 215(e) goes on to specify that "enforcement" is intended to include "penalties" that the ERO or the Commission, not a court, would impose. That intent is made most clear in subsection 215(e)(3), which states that upon finding that a user, owner or operator of the Bulk-Power System has engaged in or will engage in acts that violate a Reliability Standard, the Commission "may order compliance with a reliability standard *and* may impose a penalty against [that] user or owner or operator of the bulk-power system."[77] If the term "enforcing compliance" in FPA section 215(b) was intended to cover injunctions or other equitable remedies only, as DOE/SWPA have argued, then there would be no reason for subsection (e)(3) to give the Commission the authority *both* to "order compliance" with Reliability Standards and to "impose a penalty" for violations of those standards.

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pointed out that the term "civil penalty" is defined in Black's Law Dictionary as "a fine assessed for a violation of a statute or regulation." *Id.* at 247.

[75] 185 F.3d 529 (6th Cir. 1999).

[76] *Id.* at 532.

[77] 16 U.S.C. § 824o(e)(3) (emphasis added).

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40. With respect to the second argument of DOE/SWPA and others, that FPA section 215(e) does not explicitly refer to federal entities (or to 201(f) entities), we reject the notion that a waiver of sovereign immunity can only be effectuated if conferred under a single subsection of FPA section 215. We do not believe that the scope of the Commission's jurisdiction and obligations with respect to enforcing compliance, as described in FPA section 215(b), can be understood without reference to FPA section 215(e), and that the definition of the term "users, owners and operators of the Bulk-Power System" as set out in FPA section 215(b), which includes FPA section 201(f) entities, necessarily informs its use throughout the remaining sections of FPA section 215. Thus, we agree with DOE/SWPA when they argue elsewhere that statutory language which purports to effect a waiver of immunity must be read in context. Unlike DOE/SWPA, however, we believe this rule of construction rule applies not only to the FPA as a whole but also *within* the context of FPA section 215.

41. Finally, DOE/SWPA and others point out that the FPA section 215(b) description of jurisdictional scope and applicability refers only to the Commission's jurisdiction and not to the ERO's. We do not find this distinction to be meaningful in this context. First, as discussed above, we have held that FPA section 215(b) serves to define the scope of "all users, owners and operators of the Bulk-Power System" as that term is to be applied to the remainder of FPA section 215. Notably, the statute uses the exact same phrase -- "user or owner or operator of the bulk-power system" -- in the provision governing the Commission's enforcement authority (section 215(e)(3)), and in the provision governing the ERO's enforcement authority (section 215(e)(1)), without any indication that they are intended to have a different scope. We believe the only plausible approach to interpreting this language is to read "user or owner or operator of the bulk-power system" as having a consistent meaning throughout section 215 that encompasses entities, like SWPA, that are included in section 201(f).[78]

B. FPA Section 316A Does Not Otherwise Render Ambiguous the Grant of Authority to Impose Penalties on a Federal Entity Under FPA Section 215

42. We disagree with DOE/SWPA and other entities seeking rehearing that we failed to consider our FPA section 215 authority in the context of the rest of the FPA, and particularly that we failed to consider FPA section 316A, which grants the Commission the authority to impose a civil penalty on "persons" who violate any provision of Part II

[78] We further note that an ERO-imposed penalty cannot take effect until the 31st day after it is filed with the Commission, and that each such penalty is subject to Commission review on its own motion or on application by the recipient of the penalty. *See* 16 U.S.C. § 824o(e)(2).

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of the FPA. We fully considered whether the grant of authority to impose a penalty on a federal entity under FPA section 215 is inconsistent with or otherwise conflicts with FPA section 316A, and we found that it did not.

43. In their rehearing requests, DOE/SWPA and other entities make a number of arguments similar to those made in their initial comments in this proceeding, i.e., that FPA section 215 is merely a procedural provision,[79] that it cannot serve as an independent grant of penalty authority because it does not bear the indicia of such a grant, and that FPA section 316A is the sole source of civil penalty authority for violations of Part II of the FPA.

44. We find such a limited reading of FPA section 215 implausible. As we noted in the July 2012 Order, FPA sections 215(e)(1) and (3), separate and apart from FPA section 316A, authorize the ERO and the Commission to impose a penalty for violation of a mandatory Reliability Standard. Moreover, FPA section 316A does not mention the "ERO" and therefore cannot serve as a source of penalty authority for NERC. With respect to arguments about FPA section 215 lacking the "indicia" of a grant of penalty authority, we found, and reiterate, as follows:

> First, we note that FPA section 215(e)'s title – Enforcement -- signals the grant of enforcement authority, which includes the authority to impose a penalty . . . . Nor can we agree that the placement of FPA section 215(e) with the rest of FPA section 215 is a compelling reason to question its effect as a grant of penalty authority. Quite the contrary, if the intent was to draw a distinction between the penalty authority of the Commission under FPA section 215 (which extends to all 201(f) entities, regardless of their status as a "person" as defined in the FPA) and its penalty authority under FPA section 316A, it would be logical that Congress would have added the new enforcement authority as part of FPA section 215 and not through changes to FPA section 316A.[63]
>
> [63] Indeed, the fact that FPA section 215(e) provides that "any penalty imposed *under this section* shall bear a reasonable relation to the seriousness of the violation . . . " further shows that any intended penalties for section 215 violations be

[79] *See, e.g.*, DOE/SWPA Rehearing Request at 12; Mid-West ECA Rehearing Request at 17 (describing FPA section 215 as a substantive regulatory provision that is enforced through 316A).

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> imposed under section 215 and not another section or part. Similarly, FPA section 215(c), which governs certification of the ERO, indicates that Congress intended FPA section 215 to be an independent source of penalty authority for violations of FPA section 215. Specifically, FPA section 215(c)(2)(C) requires the ERO to establish rules to "provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties in accordance with subsection (e) . . . ." 16 U.S.C. § 824o(c)(2)(C). *See also* Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 570 (finding that the type of penalty contemplated by FPA section 215 includes monetary penalties).[80]

45. We also reject the notion that the failure to include a monetary cap in FPA section 215 indicates that the section was not intended to serve as a grant of penalty authority. As is discussed more fully in section II.C., below, we have determined that the monetary cap set out in FPA section 316A is applicable to FPA section 215 penalties. Despite this, we cannot plausibly read FPA section 215 as relying on FPA section 316A as the source for its penalty authority, and note that if FPA section 316A did not exist or were otherwise withdrawn from the FPA, the penalty authorities described in FPA section 215 would still exist and could be carried out (even if uncapped).[81]

46. Moreover, as we noted in the July 2012 Order, FPA section 215 may not place a specific dollar-value cap on penalties, but does include other significant limitations.[82] Among other things, all penalties assessed by NERC are "subject to review by the Commission, on its own motion or upon application by the user, owner or operator that is

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[80] July 2012 Order, 140 FERC ¶ 61,048 at P 47.

[81] As we found in the July 2012 Order, we find no merit in the argument that Congress would have modified FPA section 316A to refer to 201(f) entities, or section 201(b)(2) to include section 316A among the list of provisions of the FPA that are applicable to 201(f) entities if it had intended for federal entities to be subject to monetary penalties for violations of FPA section 215. On the contrary, any such modification explicitly would have made federal entities subject to penalties for *any* violation of FPA Part II. *See* July 2012 Order, 140 FERC ¶ 61,048 at PP 47, 51 ("By granting a separate penalty authority as part of FPA section 215, Congress limited federal entities' new exposure to penalties . . . to a very specific area of responsibility, *i.e.*, to violations of mandatory Reliability Standards and nothing further.").

[82] *Id.* P 48.

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the subject of the penalty," and all are required to bear a reasonable relation to the seriousness of the violation and to consider remedial steps taken by the potential recipient of the penalty, as set out in FPA section 215(e)(6).

47. Thus, we maintain that FPA section 215 acts as a separate grant of penalty authority with respect to violations of mandatory Reliability Standards. Further, we are satisfied that the waiver of immunity effected through FPA section 215 is not rendered ambiguous by FPA section 316A or any limitations it may have to "persons" as defined under the FPA.[83]

C. The July 2012 Order is Not a Departure from Prior Commission Rulings Regarding the Applicability of FPA Section 316A Penalty Caps to FPA Section 215

48. Mid-West ECA argues that the July 2012 Order effectively denies the existence of Commission precedent, in Order No. 672 and elsewhere, that the monetary caps set out in FPA section 316A are applicable to penalties imposed under FPA section 215. To the contrary, we directly addressed that precedent and what it meant in our underlying order:

> We reject DOE/SWPA and other commenters' position that the Commission's prior holdings on the applicability of the monetary limits set out in FPA section 316A to penalties imposed under FPA section 215(e) require a finding that FPA section 316A thereby limits the scope of FPA section 215. In Order No. 672, the Commission found that penalties imposed under FPA section 215 are subject to the upper monetary cap on civil penalties as set out in FPA Section 316A, but in no way suggested that FPA section 316A was the source of the Commission's (or NERC's) authority to impose a penalty for violations of a Reliability Standard under FPA section 215. In other words, the scope of the Commission's penalty

[83] The legislative history of section 215, while not dispositive, supports the conclusion that Congress did not require section 316A to govern section 215 penalties. In September 2002, the first version of what subsequently became FPA section 215(e)(6) was included in a conference committee draft of House omnibus energy bill, H.R. 4. The first two offers of that bill (HR4 Offer 001 and Offer 002) explicitly provided that section 316A would govern section 215 penalties; the third removed any reference to section 316A. The explicit rejection of a provision linking a section 215 penalty to section 316A supports the conclusion that FPA section 215 was intended to act as a separate grant of penalty authority.

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> authority under FPA section 215 is expressly set out under FPA section 215(b), and does not depend on the general penalty authority granted under FPA section 316A.
>
> In pressing this argument, DOE/SWPA quote a statement in Order No. 672 that "[t]he Commission has the legal authority to impose a civil penalty pursuant to section 316A of the FPA, which applies to a violation of any provision under Part II of the FPA, including section 215." This statement was made in the context of the Commission's consideration elsewhere in Order No. 672 of whether a monetary penalty could be imposed on the ERO or a Regional Entity, to the extent they are not acting as users, owners, or operators of the Bulk-Power System, for violations under FPA section 215.[84]

49. Thus, we disagree that the Commission has indicated, in Order No. 672 or elsewhere, that FPA section 316A is "the source of 'empowerment'" to impose a penalty for violations of Reliability Standards under FPA section 215, as Mid-West ECA and other entities seeking rehearing argue. We note that the issue before us, and the issue on which entities commented in response to the Notice of Proposed Rulemaking (NOPR) that preceded Order No. 672, was whether or not the monetary caps contained in FPA section 316A should also apply to FPA section 215 penalties, and *not* the question of whether federal entities should be subject to monetary penalties under FPA section 215. Accordingly, when the Commission "interpreted" Section 316A as establishing limits on monetary penalties for violations of a Reliability Standard, that finding cannot be read to mean that we intended (or that Congress intended) for other aspects of FPA section 316A to *supplant* FPA section 215's grant of limited jurisdiction to impose penalties on 201(f) entities that violate a mandatory Reliability Standard.

50. Nor do we agree that our position on the relationship between FPA section 215 and FPA section 316A effectively reads the word "persons" out of FPA section 316A, as DOE/SWPA have argued, or that we have not responded to the argument that if FPA section 316A applies to the size of the monetary penalty it must also govern which entities pay.[85] DOE/SWPA and these other entities seek to expand our decision regarding the applicability of FPA section 316A far beyond anything included in our ordering language. The exact language of the relevant paragraph in Order No. 672 is as follows:

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[84] July 2012 Order, 140 FERC ¶ 61,048 at PP 49-50.

[85] *See* DOE/SWPA Rehearing Request at 15-16.

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> The Commission confirms its interpretation that section 316A of the FPA establishes a limit on a monetary penalty for violation of a Reliability Standard that may be imposed by the Commission, the ERO, or a Regional RE pursuant to FPA section 215.[86]

Likewise, the Commission again held in a subsequent order that "[i]n Order No. 672, we interpreted section 316A *as setting a cap on the monetary penalties* that the Commission, NERC, and the Regional Entities could impose under FPA section 215."[87] Notably, the Commission did not hold that FPA section 316A is the source of penalty authority under FPA section 215, nor did the Commission find that language in FPA section 316A could or should supplant the specific language contained in FPA section 215 as to who is liable for enforcement and penalties pursuant to that section. Instead, the Commission determined that penalties imposed under FPA section 215, which are required to "bear a reasonable relation to the seriousness of the violation" but which are *not otherwise limited under FPA section 215 itself*, should be subject to the same monetary caps that apply to civil penalties for violations of Part II of the FPA.[88] FPA section 215 contains specific language addressing enforcement authority for violation of mandatory reliability standards as well as the universe of entities subject to 215 penalties, but does not provide for specific penalty caps. Under generally-accepted rules of statutory construction, the enforcement authority set forth in section 215 specifically addressing who is liable for penalties prevails over the more generalized penalty provision set forth in section 316A of the FPA. Likewise, under the same rule of statutory construction, it was appropriate for the Commission to interpret the more specific penalty cap set forth in Section 316A as applicable to section 215, which does not include any specific language on penalty amounts. But for the Commission to also apply the term "person" included in section 316A to replace the specific terms in section 215 identifying which entities are subject to compliance requirements and penalties as SWPA argues, would not constitute application of the statutory construction principle of the specific over the general but a revision of the specific terms in section 215 as to who is eligible for penalties, which the Commission cannot do.[89]

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[86] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 575.

[87] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,046 at n.29 (2007) (emphasis added).

[88] *See* Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 574.

[89] *See, e.g., Radlax Gateway Hotel, LLC v. Amalgamated Bank*, 132 S.Ct. 2065, 2071 (2012) ("The general/specific canon is perhaps most frequently applied to statutes

(continued…)

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D. Policy Implications and Consistency with the Flood Control Act

51. Mid-West ECA relies on arguments almost identical to those raised in initial comments in this proceeding with respect to the policy implications of imposing monetary penalties on federal entities. As argued previously, Mid-West ECA suggests that the imposition (or threat of the imposition) of monetary penalties does not provide the same kind of incentive when imposed on federal entities as it does to other kinds of users, owners and operators of the Bulk-Power System, because federal entities can readily pass the penalty costs on to their preference customers.[90] Mid-West ECA also argues that the Commission's decision in the July 2012 Order is inconsistent with its stated position on the reduced compliance incentives for RTOs and ISOs if allowed to automatically pass on their penalty costs to all members.[91]

52. We reject the notion that the imposition of penalties on federal entities is inconsistent with our stated policies regarding the need to review the pass-through of penalty costs in cases where such a review is within our jurisdiction, as it is with RTOs and ISOs. In fact, the Commission has affirmed the appropriateness of assessing monetary penalties against RTOs and ISOs for violation of mandatory Reliability Standards and the Regional Entities have imposed penalties against RTOs and ISOs for such violations.[92] Moreover, excluding federal entities from the prospect of monetary penalties would, at least from a policy perspective, be in direct conflict with the imposition of such penalties on many other entities that may pass such costs on to their

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in which a general permission or prohibition is contradicted by a specific prohibition or permission. To eliminate the contradiction, the specific provision is construed as an exception to the general one."); *see also Morton v. Mancari*, 417 U.S. 535, 550-51 (1974).

[90] Mid-West ECA Rehearing Request at 25-26.

[91] *Id.* at 26.

[92] *See* Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 634; *In re California System Operator Corp.*, 141 FERC ¶ 61,209 (2012); *Midwest Independent Transmission System Operator, Inc.*, 135 FERC ¶ 61,118 (2011); *Electric Reliability Council of Texas, Inc.*, 137 FERC ¶ 61,088 (2011).

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customers or members, including certain other publicly-owned or member-owned entities.[93]

53. We also disagree that an arguably "reduced" incentive to avoid penalties, due to the ability to pass-through the associated costs, equates to no incentive. As we noted in the July 2012 Order, "federal entities such as SWPA still have a strong incentive to develop a culture of compliance if subject to monetary penalties, whether in response to Congressional oversight or in response to the concerns of their preference customers."[94]

54. Mid-West ECA also resurrects its arguments regarding the inherent conflict between the imposition of monetary penalties on federal entities such as SWPA for Reliability Standard violations, and the Flood Control Act. Mid-West ECA notes that the Flood Control Act requires that power sold to preference customers by SWPA and similar entities must be sold "at the lowest possible rates to consumers." Mid-West ECA maintains that the imposition of a monetary penalty would necessarily "translate" into higher rates for preference customers, which they suggest inherently conflicts with the Flood Control Act's requirements.

55. We find no merit in these arguments, and find no support for such a narrow reading of the Flood Control Act. Among other things, we note that under the Flood Control Act, applicable federal entities are required to transmit and dispose of power "in such a manner as to *encourage* the most widespread use [of energy generated at applicable projects] at the lowest possible rates to consumers *consistent with sound business principles.*"[95] We do not understand this to mean that federal entities are therefore exempt from exposure to a potential cost of doing business -- in the form of 215 penalties -- that is applicable to similarly-situated, private entities that are not covered by the Flood Control Act. Moreover, we believe that the interpretation of the Flood Control Act advanced by Mid-West ECA could, by extension, preclude the imposition of *any* regulatory requirement that imposes an additional compliance cost on an applicable covered federal entity, including requirements to protect water quality or fish and wildlife in the operation of a hydroelectric facility. We cannot find any support for this interpretation of the Flood Control Act, and affirm our position that the imposition of a monetary penalty on a federal entity for violation of a mandatory

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[93] *See* July 2012 Order, 140 FERC ¶ 61,048 at P 56, n 74 (citing to *North American Electric Reliability Corp.*, 134 FERC ¶ 61,209 (2011) (affirming an $80,000 penalty against Turlock Irrigation District)).

[94] *Id.* P 56.

[95] 16 U.S.C. § 825s (emphasis added).

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Reliability Standard does not impermissibly conflict with the policies stated in the Flood Control Act.

E. The July 2012 Order Appropriately Found That Imposition of Monetary Penalties on Federal Entities Does Not Conflict with the Anti-Deficiency Act

56. Mid-West ECA and SE FPC argue that the July 2012 Order "hastily dismissed" concerns raised about potential violations of the Anti-Deficiency Act if federal entities are required to pay monetary penalties. They maintain that the Commission was instead required to "research the entity's most recent congressional appropriation, as well as any previous legislation" that might prohibit payment of a penalty, and make specific findings related to laws affecting those appropriations to ensure no conflict with the requirements of the Anti-Deficiency Act.[96]

57. We reject the notion that the Commission is required to undertake an analysis of SWPA's (or other federal entities') congressional appropriations or other applicable legislation in order to find no conflict with the Anti-Deficiency Act. As we noted in the July 2012 Order, the Anti-Deficiency Act provides that an "officer or employee of the United States Government . . . may not make or authorize an expenditure or obligation exceeding an amount available in an appropriation or fund for the expenditure or obligation."[97] With respect to the payment of administrative penalties, the Office of General Counsel of the United States General Accounting Office has concluded that "agency operating appropriations are available under the 'necessary expense' theory, to pay administratively imposed civil penalties," as long as there has been an express waiver of sovereign immunity.[98] While SWPA and the federal agencies participating in this proceeding may not agree that immunity has been expressly waived, SWPA can point to

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[96] *See* Mid-West ECA Rehearing Request at 31.

[97] 31 U.S.C. §1341(a)(1)(A).

[98] Government Accountability Office, GAO-04-261SP, Principles of Federal Appropriations Law, 3 Ed. Vol. 1, 4-144 - 4-145. *See also EPA Assessment of Penalties Against Federal Agencies for Violation of the Underground Storage Tank Requirements of the Resource Conversation and Recovery Act*, 2000 OLC LEXIS 20, 15-16 (2000) (OLC RCRA Opinion) (noting that an agency would "typically have authority to pay the penalties that have been lawfully assessed against it in the course of its conduct of agency business, pursuant to the 'necessary expense' principle of appropriations law," and that its findings with respect to the validity of a penalty in the OLC opinion served as a basis for concluding that agency appropriations would be available to pay the penalties).

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our July 2012 Order and the instant Order Denying Rehearing to support the use of its operating appropriations to cover a penalty payment as a "necessary expense," with no consequent violation of the Anti-Deficiency Act.

The Commission orders:

The requests for rehearing are hereby denied, as discussed in the body of this order, and the motions for stay are dismissed.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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Document Content(s)

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tri-State Generation and Transmission Association, Inc.,	)	
	)	**Docket Nos. EL13-11-000**
v.	)	**RD13-1-000**
	)	
Western Electricity Coordinating Council and North American Electric Reliability Corporation, Respondent.	)	

COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
IN SUPPORT OF THE WESTERN ELECTRICITY COORDINATING COUNCIL'S MOTION FOR DESIGNATION OF CERTAIN COMMISSION STAFF AS NON-DECISIONAL

Pursuant to Rule 212 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.212, the North American Electric Reliability Corporation ("NERC") hereby files these comments in support of the Western Electricity Coordinating Council's ("WECC") January 14, 2013 filing requesting that the Commission designate certain staff from its Office of Energy Policy and Innovation ("OEPI") as non-decisional in the above-captioned proceedings.

I. COMMENTS IN SUPPORT OF WECC'S REQUEST

NERC supports WECC's January 14, 2013 motion. WECC's request, if granted, will remove communication restrictions now in place and will allow the continuation of staff discussions and pre-filing meetings between and among designated OEPI staff, as well as staff from WECC and NERC, regarding the upcoming joint filing of Reliability Standard IRO-006-WECC-2 and revisions to WECC's Unscheduled Flow Mitigation Plan.

II. CONCLUSION

Wherefore, NERC respectfully requests that the Commission accept these comments and grant WECC's request to designate certain OEPI staff as non-decisional in the referenced proceedings.

Respectfully submitted,

/s/ Rebecca J. Michael

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Counsel for North American Electric Reliability Corporation

Dated: January 17, 2013

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 17th day of January, 2013.

/s/ Rebecca J. Michael

Rebecca J. Michael
Attorney for North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transmission Planning Standards

Industry Webinar: Footnote 'b'

January 8, 2012

John Odom, FRCC, Standard Drafting Team Chair

RELIABILITY | ACCOUNTABILITY






Topics

- Brief history
- Overview of “as posted” draft standard
- Changes since last posting
- Summary of needs addressed in proposal
- Major objections raised during comment period
- Balloting and next steps
- Section 321 of Rules of Procedure
- Factors to consider
- Question and answer session

TPL-001 through TPL-004

What is the current Footnote 'b'?

Table I. Transmission System Standards — Normal and Emergency Conditions

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.

History

- Issue first raised by FERC in Order No. 693 issued in March 2007 directing NERC to clarify the Reliability Standard
- In its March 18, 2010 Order, FERC directed NERC to clarify footnote ‘b’ by March 31, 2011
- Revisions to footnote ‘b’ in the existing TPL standards were filed on March 31, 2011

History (Continued)

- Order No. 762 was issued in April 2012 that:
  - Remanded the TPL Standards (with footnote 'b' revision) to NERC
  - Directed NERC to develop an appropriate modification using the expedited development process
  - Provided guidance on acceptable approaches that addressed Commission concerns
  - Directed NERC to issue a Section 1600 Data Request to collect information about the current utilization of footnote 'b'
- Order on reconsideration issued in August 2012:
  - Granted NERC's request to use the typical development process based on the commitment to deliver a new footnote 'b' to the NERC Board of Trustees (BOT) for a vote at its February 2013 meeting

History (Continued)

- Notice of Proposed Rulemaking (NOPR) was issued in April 2012 that:
  - Proposed to remand TPL-001-2 (new TPL standard)
  - Similar objections for footnote 12 since it has the same principles as the revised footnote ‘b’
  - NOPR indicates a rapid resolution of this one matter will allow consideration of other TPL improvements

Draft Standard

- The starting point for the current draft was the industry and NERC BOT approved standard
- As a result of the remand order, the Standard Drafting Team (SDT) made two major changes to the previously approved standard
  - Limited use of footnote ‘b’ to 75 MW max
  - Added Attachment 1 to provide the required details to the stakeholder process that had been previously approved by industry

Data Request

- Utilized NERC 1600 Data Request to establish threshold value and 75 MW limit
- 100% participation (189 respondents)
  - 171 respondents (90%) reported no instances where they utilized footnote ‘b’ in their planning process
  - 18 respondents (10%) reported instances where they utilized footnote ‘b’
- 78 instances were reported
- Maximum value reported – 75 MW
- Average value – 19.5 MW

As-Posted Draft Standard

- Attachment 1:
  - Section I – Provides required details for the stakeholder process
  - Section II – Outlines the information needed for inclusion in the process
  - Section III - Describes instances where additional steps are required

As-Posted Draft Standard (Continued)

- Key components for application of Footnote
  - Utilization of footnote cannot exceed 75 MW of planned Non-Consequential Load Loss
  - In the Long-Term Transmission Planning Horizon, planner documents use of footnote
  - In the Short-Term Transmission Planning Horizon, planner must meet conditions of Section I and Section II of Attachment 1
  - In addition, before footnote can be applied in Year One of the Planning Assessment, Section III defines the circumstances where additional actions are required

Footnote Changes Since Last Posting

- In the main body of footnote ‘b’, clarified that Consequential Load Loss and Interruptible Demand (or DSM) are not counted toward the 25 MW or 75 MW thresholds
- Clarifications of two items in Section II of Attachment A
  - In Item 2b, changed “Assessment” to “An explanation”
  - In Item 5, changed “mitigate” to “alleviate”
- Minor clarifications in Section III of Attachment A
  - Changed “assure” to “ensure”
  - Made regulatory authority references consistent

Summary of Needs Addressed

- With this draft standard, the SDT has:
  - Clearly defined the parameters of the stakeholder process
  - Established a quantitative criteria by limiting the maximum amount of Non-Consequential Load Loss that can be planned to be interrupted using the footnote to 75 MW

Major objections raised

- The 75 MW cap will require construction of major Transmission projects with little or no real benefit
  - While a construction alternative may be the best alternative, there are other ways to alleviate the need
    - Change Transmission configuration
    - Change generation dispatch
    - Use conditional Firm Transmission Service
    - Convert Firm Demand to Interruptible Demand
    - Utilize Demand Side Management

Major objections raised

- The use of Footnote ‘b’ and any limitations should be set by local regulators
  - FERC addressed this with Order 693 in March 2007 (see paragraphs 1792 – 1794)
  - FERC considers this matter to be a fundamental issue of Transmission service anticipating no planned interruption and directed the ERO to clarify the standard while considering comments through the standards development process

Balloting and Next Steps

- Revised TPL-002-1c (footnote ‘b’) and TPL-001-2a (footnote 12) are posted for a successive ballot ending on January 11, 2013
- Results will be submitted to the NERC BOT for consideration at their February 7, 2013 meeting
- Action taken by the BOT will depend on ballot results
  - An affirmative vote will result in normal processing and filing of the revised standards
  - A negative vote could result in the consideration of utilization of Section 321 of the Rules of Procedure

Section 321 – Rules of Procedure

- Developed to address the mandated obligation of the ERO to respond to FERC directives and remanded standards
- Establishes guidelines and procedures to give the BOT the ability to file standards that meet FERC directives that may not have enough industry support to be approved under normal circumstances

Factors to Consider

- Clarification efforts for Footnote ‘b’ and the other requirements of TPL standards have been on-going for 5+ years and the BOT approved TPL-001-2 cannot be finalized until the footnote ‘b’ issue is resolved
- BOT approved TPL-001-2 provides many improvements including:
  - Addresses FERC Order 693 directives
  - Addresses planning concerns raised in Order 754
  - Removes ambiguity and provides more certainty for planning



Question and Answer Session

Website: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

SUMMARY OF STAKEHOLDER COMMENTS AND RESPONSES
PROPOSED REVISIONS TO THE RULES OF PROCEDURE APPENDIX 4D

List of Acronyms Used for Commenters

AEP – American Electric Power

Ameren – Ameren Services

APM, Brazos, Sunflower – ACES Power Marketing (APM), Brazos Electric Power Cooperative, Inc. (Brazos), Sunflower Electric Power Corporation (Sunflower).

BPA – Bonneville Power Administration

CE – Consolidated Edison Company of NY, Inc.

Consumers Energy

Dominion

Duke Energy – Duke Energy Corporation

EEI – Edison Electric Institute

ERCOT – Electric Reliability Council of Texas, Inc.

Entergy

GSOC – Georgia System Operations Corporation

LADWP – Los Angeles Department of Water and Power

Luminant - EFH Luminant

MRO NSRF – Midwest Reliability Organization NERC Standards Review Forum (composed of MRO members).

MidAmerican Energy – MidAmerican Energy Company

National Grid

NextEra – NextEra Energy, Inc.

NU – Northeast Utilities Service Company

PacifiCorp

Pepco – Pepco Holdings, Inc.

PGE

PPL – PPL Companies/PPL Corporation

SCE – Southern California Edison Company

Southern – Southern Company Transmission

SPP – Southwest Power Pool, Inc., Westar Energy, City Utilities of Springfield, Omaha Public Power District, Nebraska Public Power District, and Southwestern Power Administration.

TECO – Tampa Electric Company

TAPS and APPA – Transmission Access Policy Study Group and American Public Power Association

Tucson Electric – Tucson Electric Power

TVA

Change proposed by NERC	Comment received	Outcome	Justification/Notes
N/A	**General comments regarding streamlining of TFE process** GSOC commends NERC for the changes and for streamlining the process and believes there are many excellent changes including adding the class-based categories, removing quarterly reports and combining Part A and Part B documentation. SPP et al. find these changes to be very helpful to Responsible Entities and applaud NERC for their efforts to streamline the process. Many Responsible Entities have limited staff and their time will be better spent on the more valuable activities of security and reliability than of frequently submitting reports on a TFE which will not	N/A	NERC appreciates the overall support to the proposed revisions as well as the requests for clarification that allow NERC to develop more clear language in response. Assuming the NERC Board approves the current proposal, NERC will file it with the applicable governmental authorities (e.g., FERC). Supportive comments filed with FERC are appreciated as well. The revisions will not be implemented prior to receipt of FERC approval. NERC cannot estimate the amount of time it would take for such approval to be obtained. In addition to the responses provided by NERC to specific questions in this matrix, the following resources are also available. NERC staff and WECC staff held a webinar on October 31, 2012 to discuss the proposed revisions. A copy of the webinar slides is available at http://www.nerc.com/files/TFE%20Webinar%20Slides-10_31_12_webinar%20(3).pdf.

Change proposed by NERC	Comment received	Outcome	Justification/Notes
	change until equipment is retired, new standard language is effective or other long-term activity occurs. NU fully supports the proposed changes to decrease administrative burdens on both Registered and Regional Entities. NU appreciates NERC allowing the Industry to comment on the proposed changes, as well as NERC's efforts to streamline its processes after the initial implementation of Appendix 4D. NU fully supports the concept of combining the Part A and B forms into a single TFE request form, but had some need for clarification in the following areas [noted elsewhere in this matrix.] LADWP supports the proposed changes to Appendix 4D and believes that given that most Technical Feasibility Exceptions (TFEs) relate to low-risk issues, have common rationales, and involve similar devices, the proposed changes will reduce the existing TFE process, which is labor-intensive and provides little to no benefit in mitigating risks to the Bulk Power System. SCE supports approval of the proposed amendments. SCE believes they will provide for, and enable, greater reliability of the bulk electric system ("BES") in North America as follows: The amendments focus the scope of the Technical Feasibility Exception (TFE) process upon those issues requiring urgent attention of the Regional		

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	Entities. As currently drafted, the TFE provisions of Appendix 4D requires individual TFEs for individual assets, even those that fall within the same class. Processing individual application that – in many instances – may be virtually identical in nature, consumes the staff and resources of the regional entities that must repetitively process these applications. The Proposed Amendments address this problem by creating class-based categories of devices, thereby streamlining the application process. The streamlined process should free up human resources at regional entities. The Amendments will also streamline the TFE application process by limiting the number of changes to TFEs that registered entities will need to report to the Regional Entities. Currently, Appendix 4D requires Registered Entities to amend their TFEs for even minor changes – a time consuming process that requires Regional Entities to review minor changes to system components that have no effect on the reliable operation of the BES – an inefficient use of human resources. In contrast, the Proposed Amendments will require revisions and reports only for "material changes" – a much smaller subset. By limiting the number of documents and reports for Regional Entity review to those that result in actual changes, the Regional Entities will have greater human resources to focus on substantive matters affecting the		

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	reliable operation of the BES. TECO appreciates the opportunity to provide comments on the Proposed Revision of NERC Rules of Procedures Appendix 4D. TECO thanks NERC for being willing to consider changes that as a result will make a positive impact by reducing some administrative burden, while maintaining BES reliability. TECO respectfully presents its concerns and request additional clarifications on the proposed revisions with the objective of improving the proposal [reflected elsewhere in this matrix]. ERCOT appreciates the revisions made to NERC Rules of Procedure Appendix 4D. These changes provide much needed reform of the process and add value in managing these types of requests. ERCOT offers the following comments on the proposed changes to NERC Rules of Procedure Appendix 4D [added to relevant Sections below]. On behalf of its member companies, EEI appreciates the opportunity to provide the following brief comments on the Proposed Revisions to NERC Rules of Procedure Appendix 4D. EEI commends NERC for being willing to contemplate changes that have the potential for reduction of administrative burden, while maintaining BES reliability.[1]		

[1] Pepco, Ameren, PGE, Duke Energy, Tucson Electric, MidAmerican Energy, National Grid, and Luminant support EEI's comments.

Change proposed by NERC	Comment received	Outcome	Justification/Notes
	The EEI members share the goals and objectives of streamlining procedures while maintaining the reliability of the BES, and EEI respectfully offers the following suggestions and proposed revisions with the aim of improving the proposal. [added to relevant Sections below]. TAPS and APPA appreciate the opportunity to comment on the proposed changes to the Rules of Procedure Appendix 4D. TAPS and APPA support NERC's efforts to streamline the TFE process so that Registered Entities, and Regional Entities, can refocus resources onto activities that directly impact grid reliability. TAPS and APPA also support the general direction of NERC's proposed changes to the process. By eliminating the two-phased review process, reducing overall processing time, and eliminating the periodic reporting requirement, these changes will reduce administrative burden and improve reliability. TAPS and APPA do, however, have four specific suggestions for improvements to the proposed changes [noted elsewhere in this matrix]. TVA welcomes the streamlining of the TFE process and the corresponding reduction in administrative effort. APM, Brazos Electric, and Sunflower Electric agree with NERC that streamlining the TFE process for submission and approvals of TFEs is		

Change proposed by NERC	Comment received	Outcome	Justification/Notes
	necessary moving forward. APM, Brazos Electric, and Sunflower Electric do have some concerns as outlined [elsewhere in this matrix.] BPA applauds the efforts of NERC to revise the current TFE process in Appendix 4D of the NERC Rules of Procedure. BPA fully supports the goal these changes are trying to achieve. The PPL Companies support the goal of realigning the burden and benefits associated with the TFE process, the intent to streamline the process for approving TFEs, and the timing to make revisions as quickly as reasonably possible to alleviate the burden for existing TFEs as well as new or amended TFEs for either CIP Version 3 and future CIP Versions 4 and 5. However, they are concerned with timing and some of the proposed revisions. PPL Companies support EEI's comments concerning this matter.		
N/A	**General comments regarding implementation of revisions** Concerning Approved, Pending TFEs that were in place or in process before proposed revisions take effect: EEI believes that it is very important that any revisions to the existing TFE process specifically address requirements for Approved, or Pending TFEs that were in place or in process before proposed revisions take effect. It is our understanding that once the Proposed Revisions become effective, each Responsible Entity must submit a	See clarifications made in attached redline in new section 4.3 regarding a "baseline" submittal at the time of first TFE request or MCR after approval of revisions to Appendix 4D.	A sample TFE request is available at http://www.nerc.com/files/Proposed_TFE_Form_Jan2013.pdf. The information to be collected through the request is specified in section 4.2 (as revised pursuant to the comments received) and will be the same in each Regional Entity footprint. No evidence will be required, unless specifically requested by the Regional Entity. The form of entering the data corresponding to the spreadsheet cells may vary depending on the specific Regional Entity's software requirements. While we recognize that the existence of multiple software platforms across the ERO may cause some burden, this is not a burden that is created or exacerbated by the TFE process or the proposed revisions. As noted above, the revisions proposed herein will not be implemented

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	MCR for all active TFEs - previously approved and pending. This initial MCR will be used to develop a spreadsheet, which will capture all of a Responsible Entity's TFEs and as well as future material changes. Once the initial spreadsheet is developed (presumably by the Regional Entity), future MCRs will be simple for the Regional Entity (e.g. adding or modifying a row of the required data to the Responsible Entity's TFE spreadsheet) and Responsible Entity (e.g., providing a list of the Required Information for each material change). It is also our understanding that Required Information (data required by this TFE spreadsheet) will be consistent among the Regional Entities; however, the format method to report this data (e.g., a list or spreadsheet) may be different among the Regional Entities. Because a number of Responsible Entities are subject to compliance under multiple Regional Entities, EEI strongly encourage NERC to develop a common, clear, and easy to use reporting format for use by each of the Regional Entities to avoid a Responsible Entity from having to submit the same report in multiple formats, which could increase their administrative burden initially in developing the spreadsheet with approved and pending TFEs as well as the long term when submitting MCRs. A standard format will also ease the Regional Entity's administrative burden if Responsible Entities submit the Required Information in different formats (e.g., spreadsheets with different rows and columns). Standardizing the MCRing format supports NERC's goal to reduce the administrative burden while maintaining reliability.		prior to receipt of FERC approval. NERC cannot estimate the amount of time it would take for such approval to be obtained. Regarding the transition from the existing process to the proposed revisions, at the time of the first (a) initial TFE request or (b) MCR that is required to be submitted after approval of the proposed revisions, a Responsible Entity would submit a complete TFE spreadsheet to reflect existing TFEs as well as the new information. This one-time submittal will be followed by the maintenance of this spreadsheet, either through additional TFE requests or MCRs pertaining to TFE requests already approved. The submittal of this baseline TFE spreadsheet will not reopen any TFEs already approved under the old process or restart the review process of pending TFEs. As discussed herein, MCRs will be used for any changes to an approved TFE while an amendment will refer to changes to a pending TFE request. The MCR review process is identical to that of a TFE request. The new streamlined reporting requirements will apply to all previously approved TFEs. Appendix 4D is procedural in nature and does not depend on which version of the CIP standards is in effect. The process will be the same and not be affected by the upcoming revisions to the CIP standards. Assets may need to be added to or removed from an entity's TFE spreadsheet in accordance with the processes described in Appendix 4D (the initial TFE request, for adding new assets, and the MCR, for removing assets).

Change proposed by NERC	Comment received	Outcome	Justification/Notes
	Concerning Approved, Pending TFEs that were in place or in process before proposed revisions take effect, SCE believes t is very important that any revisions to the existing TFE process specifically address requirements for Approved, or Pending, TFEs that were in place or in process before the proposed revisions take effect. SCE proposes that there be no requirement to modify, convert or change any Approved, or Pending TFEs that were in place or in process before the proposed revisions take effect. PacifiCorp suggests that any revisions to Appendix 4D should specifically address the conversion of Approved or Pending TFEs that existed before the proposed revisions take effect. PacifiCorp proposes that NERC should not impose any requirement for registered entities to modify any existing Approved or Pending TFEs until such time as the TFEs require amendment due to a Material Change. Overall, AEP is in agreement with the proposed changes regarding TFEs, and encourages NERC to implement them as soon as practical. However, AEP does have some questions and comments that need to be addressed in the new Appendix 4D before its approval [reflected elsewhere in this matrix.] Is there an associated "implementation plan" following its eventual approval by FERC?		

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	NU - Examples: NERC should consider providing sample forms / example scenarios as attachments to Appendix 4D to add clarity to the process description. Concerning current effective TFEs with both Part A's & Part B's, Consumers Energy asks if in the proposed Appendix 4D, could a section be added advising industry on how to address current effective TFEs with both Part A's & Part B's? If those TFEs are left as are, what should an entity do if an amendment is needed? Should such an entity submit a MCR with the newly required information? The proposed changes do not indicate how the new procedures will affect TFEs that have already been approved under the existing procedures or TFE requests that are pending when the proposed changes take effect. TAPS and APPA suggest that NERC confirm that there is no requirement to change or convert any approved or pending TFEs. TAPS and APPA also suggest that NERC clarify that TFEs approved under the existing rules will be subject to the reporting rules in the new procedure, which replace quarterly and annual reports with the MCR. To facilitate consistency among the Regional Entities. APM, Brazos Electric, and Sunflower Electric encourage NERC to use a single uniform spreadsheet similar to the FFT process for the TFE program.		

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	Use of different spreadsheets among the Regional Entities, may leave the potential for inconsistency among the Regional Entities and may not streamline the TFE program because it does not provide a single filing process as outlined. For example, for registered entities that are in multiple Regional Entities use multiple spreadsheet formats and submission into different portals is duplicative and unnecessary. NERC should take advantage of this opportunity to streamline the process by creating a single portal to submit the data in a uniform format. Considerable effort is required to monitor multiple regional portals and track those annual review dates. Registered Entities who have multiple NERC Compliance Registry (NCR) numbers due to functional registrations, i.e., GOP and TOP, should be able to enter both NCRs in one spreadsheet and not have two TFE spreadsheets per region. BPA has some procedural questions that need to be answered. There is a need for an implementation plan and effective date. Guidance on how existing TFEs, submitted, accepted, or approved, will be handled. PPL and MRONSRF - The proposed revisions are not clear if the existing approved and pending TFEs are grandfathered or have to be redone. Section 4 needs to include a statement that approved and pending TFEs as of the effective date of the revised Appendix 4D do		

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	not have to be revised or redone. PPL - In addition, there are questions about the impact of future versions of the CIP standards (Version 4 by April 1, 2014, and Version 5 in later years): • The bright line criteria for CIP Version 4 will create a recalibration across the country of Critical Assets and corresponding Covered Assets in CIP scope. This will impact TFEs by adding and removing Covered Assets due to implementation of the bright line. • CIP Version 5 changes the requirements to which TFEs apply. Though CIP Version 5 approvals are not complete and implementation has not been ordered, it is reasonable to consider now if any provision can and should be made to recognize changes to TFEs as a result of recalibration for CIP Version 5. It is constructive to have stable TFE Required Information as all entities prepare for CIP Version 4, and eventually CIP Version 5 in order to be more efficient and present a fair representation of why the numbers change with the transitions to new versions. Also, CIP Version 5 retains TFEs, but makes other changes. It eliminates CIP-003-4 R3 exceptions and their associated senior manager approval. It defines exceptional circumstances and incorporates them in seven requirements, but does not require senior manager approvals. Finally, CIP Version 5 requires senior manager approvals		

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	only for identification of BES Cyber Systems (CIP-002-5 R1), policies (CIP-003-5 R1 and R2), and revisions or extensions to uninstalled patches mitigation plans (CIP-007-5 R2).		
N/A	**General comments regarding the process of revising the Rules of Procedure as applied in this case.** To ensure the appropriate SMEs have an opportunity to review these proposed changes, APM, Brazos Electric, and Sunflower Electric encourage NERC to clarify in all future announcements that the changes to Appendix 4D impact CIP compliance and the Technical Feasibility Exception process. EEI welcomes this opportunity to provide substantive comments to NERC in advance of a proposal being taken to the Board of Trustees. As further support for the effort, EEI membership welcomes and encourages NERC to provide the opportunity to review the next draft of proposed changes prior to submission to the Board of Trustees. EEI appreciates the effort that NERC has made to inform stakeholders about the proposal, and the use of a webinar to solicit questions from industry stakeholders. PPL - Paragraph 1402 in the Rules of Procedure for amendments states: "In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives	N/A	NERC appreciates the comments on the process for proposing revisions to the Rules of Procedure. That process includes broad participation by interested stakeholders through written comments, participation in webinars and discussions with NERC staff. The proposed changes were also on the agenda for the NERC Members Representative Committee meeting in November 2012. The process, however, is not identical to the standards development process or the process utilized to identify candidates for retirement. Due to the volume of comments received, as well as the extension of time granted for comments to be submitted regarding the proposed revisions, NERC moved the date of the submittal of the proposed changes to the NERC board so that each comment could be considered and addressed. This matrix is intended to provide additional transparency regarding the comments received, any changes or clarifications resulting from such comments and associated rationale. In this particular case, the incremental changes to Appendix 4D resulting from comments are relatively small. Most of the comments required clarification rather than a modification of the proposed language. Therefore, an additional posting period is not necessary and would further delay implementation of this project which has broad support and will result in significant benefits. The announcements associated with the proposed revisions made it clear that the revisions related to the TFE process. NERC is not aware of any issues regarding the clarity of the communications on this matter.

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	Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate." The intent to deliver proposed changes to the NERC BOT on December 19, 2012 assumes input can be incorporated in time for the BOT meeting and does not allow time to adequately, openly and transparently share revisions to the proposed changes with stakeholders, including the Member Representative Committee and registered entities, before presenting them to the BOT. PPL - The changes to Appendix 4D are proposed at a time that other significant changes are also in progress. Project 2013-02 - Paragraph 81 proposes criteria for identifying requirements that could be removed from the Reliability Standards or revised with little effect on reliability and an increase in efficiency. The TFE process imposes obligations that should have to meet the same criteria as requirements in the standards. Criteria from Project 2013-02 - Paragraph 81 relevant to TFEs include: • Overarching: "In the event no responsible entity performed the FERC-approved Reliability Standard requirement, there would be little or no impact to the protection or reliable operation of the BES." • Technical, including: Administrative, data collection/data retention, purely documentation, purely reporting, periodic updates		

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	MRONSRF strongly encourages NERC to provide a revised draft to stakeholders for comment before providing to the NERC Board of Trustees due to the extent of the revisions and the extent of details identified in comments. Stakeholders welcome the opportunity to support the process through comments.		
N/A	**General comments regarding further improvements.** MRONSRF - primarily the processing of TFEs and streamlining the approval process. Improving these processes is welcome and necessary, but should only be an interim step. An administrative documentation burden remains as a result of these revisions for processing. Please consider that: • TFE documentation and administration does not produce a reliability benefit • implemented compensating measures and/or mitigation do benefit reliability. An approach that focuses on reviewing compensating measures and/or mitigation measures at a macro level would more efficiently focus all stakeholder resources on reliability benefits rather than on documentation administration at a very detailed level. Compensating and/or mitigating measures implemented often benefit all cyber assets within the ESP and PSP, not just the cyber	N/A	NERC appreciates the suggestions regarding further improvements. The approval of the proposed revisions does not preclude further enhancements to the TFE program. However, increasing the scope of the proposed changes at this stage would unnecessarily delay the implementation of proposed changes that have been in discussion for several months and enjoy broad support.

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	assets which cannot meet strict compliance for one or more sub-requirements. The revised TFE approach should focus on examining examples of these measures for each TFE requirement, perhaps as part of the audit process, in place of ongoing administrative paperwork. Consider the following. Per the Sept. 28, 2012, NERC annual TFE filing to FERC: "a large majority of Responsible Entities have implemented multiple compensating and mitigating measures for Covered Assets, and, in general the mitigating and compensating measures of approved TFEs that were implemented in lieu of strict compliance with applicable Reliability Standards accomplished the stated alternate compliance objective. As a result, the level of security for the BES achieved through the TFE process is comparable to strict compliance with the applicable Reliability Standards." Further, a reliability-centered approach would identify issues with compensating and/or mitigating measures as violations instead of today's practice of identifying violations for paperwork even if measures are in place. Per the posted summary of proposed revisions, "Experience has shown that the majority of the TFE requests relate to low-risk issues, have common rationales and justification, are supported by common evidence, and often involve similar devices across		

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	registered entities nationwide." Ultimately, accountability for implementing compensating and/or mitigating measures can be achieved more efficiently and with lower cost for all stakeholders by substantively revising Appendix 4D's approach or replacing 4D entirely with existing CMEP mechanisms. Adopting substantive changes in the TFE approach would: • compliment the paragraph 81 project. • benefit the implementation and operation of CIP version 5 significantly.		
N/A	**Other general comments.** While the Amendments will, as proposed, provide for substantial improvements to the reliability of the BES, SCE submits the following edits for greater efficiency or clarity: throughout the document, suggesting modifying "…Applicable Requirement…" to "…Applicable Standard and Requirement…"	No additional change.	"Applicable Requirement" is defined in Appendix 4D as "A Requirement of a CIP Standard…." It is not necessary to add the word "Standard" to the definition.
Appendix 4D			
Section 2.11 – References to "rejecting" and "rejection" of a TFE request were deleted in this section and throughout the document to reflect the consolidation of the screening and substantive review phases of the TFE process. Under the proposed revisions, TFE requests would no longer be subject to acceptance or rejection, but rather	No comments received.	N/A	N/A

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approval or disapproval.			
New sections 2.17 and 2.18 – The defined terms "Material Change" and "MCR" were added to reflect a streamlined reporting requirement for changes to an approved TFE request.	**Comments regarding clarity of definition.** EEI finds the terms "key data'' and "could include" used in Part 2.17 subjective and ambiguous, which may result in the inconsistent interpretation or application of this rule. EEI offers an alternative definition for "Material Change": *A change in fact that modifies the statement of basis for the TFE or its compensating measures; extends the expiration date of the TFE, or reflects a Responsible Entity's achievement of Strict Compliance with the Applicable Requirement."* Dominion states that the terms "key data'' and "could include" used in Part 2.17 are subjective and ambiguous and don't provide the required clarity to ensure consistent interpretation or application of this rule. Concerning the new definition of "Material Change" under Section 2.17, SCE finds that the terms "key data'' and "could include" used in Part 2.17 are subjective and ambiguous and don't provide the required clarity to ensure consistent interpretation or application of this rule. An alternative definition for "Material Change" is offered by SCE: "*An update to an approved TFE that modifies the statement of basis for*	See clarifications made in attached redline regarding sections 2.17 and 2.18.	NERC has provided additional clarification on the MCR discussed below and in the attached redline. The process of submitting a MCR is essentially identical to the process of submitting a TFE request. The review and approval process for the MCR is also essentially identical to that of the initial TFE request and any necessary substantive review or verification may be made after approval of the MCR through a CMEP method. Except as noted elsewhere with respect to the very first MCR submitted after the approval of the proposed revisions to Appendix 4D, which would require a Responsible Entity to create its TFE spreadsheet for the first time, with legacy and new information, the MCR will consist of one or more rows into the entity's existing TFE spreadsheet. No evidence is required, unless requested by the Regional Entity. NERC also notes that the information requirements associated with both the initial TFE request and the MCR have been significantly reduced and streamlined and there are no evidentiary requirements unless specifically requested by the Regional Entity. It is necessary to leave open the possibility that the Regional Entities or NERC may require additional information not specified in Appendix 4D, at any stage of the process. However, experience has shown that in the vast majority of cases, no additional information would be required. The issue of an amendment vs. a material change is discussed elsewhere in this matrix. Essentially, modifications to an approved TFE would be reported to the Regional Entity through the MCR, but not through an amendment. The MCR would include additional devices of the same type of an approved TFE. This is necessary to provide the Regional Entity information regarding the actual scope of the TFE. If the additional device is identical to those already subject to the TFE then most likely the review process for the MCR will be simple. However, the Regional Entity must have the opportunity to make the determination that the device in question is the same and that the existing mitigating measures are appropriate. Note that a decrease in device count would not trigger the need for a MCR. Similarly, Regional Entities need information on changes to the expiration date for TFEs. Note that an expiration date is not required as the TFE can be open ended. However, if one is provided, a change to the expiration

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	the TFE or its compensating measures; extends the expiration date of the TFE, or reflects a Responsible Entity's achievement of Strict Compliance with the Applicable Requirement." TAPS and APPA believe it is important that Registered Entities can clearly identify changes that will require the submission of a MCR. TAPS and APPA find the proposed definition of Material Change in Section 2.17 too ambiguous and prone to differing interpretations. TAPS and APPA suggest revising the definition as follows to reduce the ambiguity: 2.17 Material Change: A change in facts that modifies the statement of basis for a TFE or its compensating measures; extends the expiration date of a TFE, or reflects a Responsible Entity's achievement of Strict Compliance with the Applicable Requirement. PPL and MRONSRF - "modifies key data" and the examples are not definitive enough and create inconsistency opportunities. **Comments related to increase in device count and expiration dates.** AEP notes that if a new device type or manufacturer is introduced which is not part of an existing TFE, it would be understandable to require an amendment. However, AEP contends that simply adding another device of the same manufacturer and model covered by an existing TFE should not		date must be reported through the MCR. The proposed revisions balance the need to streamline the process and eliminate burden with the need for information. Responsible Entities are encouraged to consult with Regional Entities with any questions regarding the process or whether the MCR is required in any specific circumstance.

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	constitute a material change, and thus should not require amending the existing TFE. GSOC also finds the concept of reporting when a material change is made excellent; however it believes some of the changes are not actually material: increasing the number of devices, especially if they are in the same class, should not be a material change; changing an expiration date should not be a material change since projects often experience delays and a TFE should remain effective until the Responsible Entity submits a termination notice or the Regional Entity terminates the TFE for cause. EEI - Part 2.17 language indicates that an increase in device count is considered a material change. The rationale offered as a basis for this position during the NERC Webinar conducted on October 30 suggested that because there were additional devices that could not achieve strict compliance, the Regional Entities would need to be informed of the increase to assess the impact on the basis for the TFE and the associated compensating and mitigating measures. This doesn't account for increases in device counts that involve the same device type (e.g., make and model), and for which the same compensating and mitigating measures are applied. Increases in device counts alone, should not be considered material to the reliability of the BES. EEI does not believe that		

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	an increase in device count, particularly device counts associated with approved TFEs or device counts associated with approved "Class Type" TFEs represent a "Material Change." If numbers are required, EEI propose that they be provided on an annual basis, once a year. Dominion - Additionally, Part 2.17 language indicates that an increase in device count is considered a material change. The rationale offered as a basis for this position during the NERC Webinar conducted on October 30 suggested that because there were additional devices that could not achieve strict compliance, the Regional Entities would need to be informed of the increase to assess the impact on the basis for the TFE and the associated compensating and mitigating measures. This doesn't account for increases in device counts that involve the same device type (e.g., make and model), and for which the same compensating and mitigating measures are applied. Increases in device counts alone, should not be considered material to the reliability of the BES. Dominion proposes the language in 2.17 be modified to read: "2.17 Material Change: An update to an approved TFE that modifies the statement of basis for the TFE or it's compensating measures; extends the expiration date of the TFE, or reflects a Responsible Entity's achievement of Strict Compliance with the Applicable Requirement."		

Change proposed by NERC	Comment received	Outcome	Justification/Notes
	SCE - Part 2.17 language indicates that an increase in device count is considered a material change. The rationale offered as a basis for this position during the NERC Webinar conducted on October 30 suggested that because there were additional devices that could not achieve strict compliance, the Regional Entities would need to be informed of the increase to assess the impact on the basis for the TFE and the associated compensating and mitigating measures. This doesn't account for increases in device counts that involve the same device type (e.g., make and model), and for which the same compensating and mitigating measures are applied. Increases in device counts alone, should not be considered material to the reliability of the BES. SCE does not believe that an increase in device count, particularly device counts associated with approved TFEs or device counts associated with approved "Class Type" TFEs represent a "Material Change." In addition, the description for a Material Change states, among others, that an increase in device count would be considered to be "key data". Does this mean a decrease in device count would not require a Material Change? If numbers are required, SCE proposes that they be provided on an annual basis, once a year. Regarding Section 2.17, ERCOT requests that device counts be removed from the types of changes		

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	listed that would be material in nature. When there is an approved TFE for a device, a change in the asset count would not be material in determining risk. In regards to Section 2.17, Entergy believes that an increase in device count should not qualify as a Material Change, if an identical device type is added with the same compensating/mitigating measures, same basis, same expiration date, and is supported by the same vendor evidence. In a rapidly changing environment, this could lead to a slowing of the process as multiple MCRs are filed for the same TFE within the initial review period, or the initial review period of a previous MCR. Entergy recently received a request to file their 3rd Quarter TFE Report, and in the request it is stated that device count changes need only be captured on the quarterly report, and amended TFEs filed at least annually. This supports the belief that device count is not a significant change that should necessitate a review. In regards to Section 2.17, NextEra suggests removing changes to approved TFE device counts as a scenario that will be considered a Material Change. Changes solely to device counts while other information in the already approved TFE (e.g., mitigating and compensating measures) remains unchanged should not be defined as a Material Change as there is no change in the risk to the BES posed		

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	by the inability to achieve strict compliance. **Comments regarding Material Change vs. Amendment.** PPL and MRONSRF - Required content for MCRs versus amendments is different, but partially duplicative. The Regional Entities have different actions for each. PPL proposes that the concept of Material Change and MCR not be created. MRONSRF proposes alternative definition for Material Change – An update to an approved TFE shall be filed within 60 days after a change for any of the following: • modifies the statement of basis for the TFE or its compensating measures • extends the expiration date of the TFE • reflects a Responsible Entity's achievement of Strict Compliance with the Applicable Requirement. (Approval should not be required in 3.4 if Strict Compliance has been achieved). BPA requests clarification regarding: The difference between MCR and Amended TFE. Concerning the MCRs vs. Amendments: Although EEI agrees with the need to maintain and report "Material Changes" as defined above, EEI is concerned with the proposed draft as it appears to require both the use of amendments *and* MCRs. EEI		

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	believes that the objective of focusing on activities that can directly impact reliability, and decrease administrative tasks would best be served by requiring either amendments *or* MCRs, but not both. TECO supports EEI comments in this section. TECO has additional concerns not addressed by EEI, as well as, requesting further clarification in some areas as follows. Concerns: This may create more reports if an amendment is required to be filed with the MCR; New filing process and related new reporting documents should be more clearly defined. Clarification items: How should the justification be documented in the current quarterly and annual report?; Are vendor letters dated within a year required?; and What would the frequency be for the MCR? Furthermore, concerning the MCRs vs. Amendments under Section 2.17, although SCE agrees with the need to maintain and report "Material Changes" as defined above, SCE is concerned with the proposed draft as it appears to require both the use of amendments and MCRs. SCE believes that the objective of focusing on activities that can directly impact reliability, and decrease administrative tasks would best be served by requiring either amendments MCRs but not both. Entergy finds that the difference between a MCR and an Amendment		

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	is not clearly defined. Section 6.5 suggests they are the same with the statement "The MCR shall be submitted as an amendment". The definition for a Material Change, as found on page 4 section 2.17, is nearly identical to that of an amendment as defined on page 19, section 7.2.1, lines 3-5. This leads Entergy to question the difference between an Amendment and a Material Change, as well as the necessity of having two separate documents and/or processes. Entergy also finds that the content of a MCR is not clearly defined in the same manner that a TFE Request is defined, as found on page 7, section 4.2, items a-h. PPL - While seeming to lessen reporting burdens through elimination of annual and quarterly reports, the proposed revisions could actually create more reports. The revisions create a MCR. It is filed with, but apparently in addition to, an amendment. Based on experience, in net this will create more reports in total. **Comments regarding process and content of Material Change Report (MCR).** SCE also notes that Section 2.18 identifies a MCR as a report submitted by the Responsible Entity to the Regional Entity in the event there is a Material Change to the facts underlying an approved TFE. Section 3.4 also references a MCR, but this Section goes further by stating, "…the Responsible Entity		

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	shall submit a MCR providing continuing justification for the TFE or verifying Strict Compliance with the Applicable Requirement has been achieved." SCE suggests adding to Section 2.18 the verbiage found in Section 3.4 which provides additional guidance for a MCR. In regards to Section 2.18, Entergy finds the content on a MCR that Regional Entities are reviewing is never identified. It is only stated that Responsible Entities must submit MCRs that are signed and reviewed. Specific MCR content should be outlined in the NERC Rules of Procedure similar to the new TFE request. SPP - The MCR process will be very important in making the TFE process more efficient and the information more relevant. SPP understands the need for NERC and the Regional Entities to maintain relevant information on the scope of risk to the industry, but hope that can be balanced with an appropriate level of information reporting. If the process developed for managing and submitting Material Changes is onerous, then Responsible Entities, Regional Entities and NERC will have gained little in these proposed changes. TVA has the following concerns however: 1. Elimination of periodic reporting subjects us to potentially short notice reporting obligations to the region.		

Change proposed by NERC	Comment received	Outcome	Justification/Notes
	2. Timeframe for MCR to be submitted after Material Change activities are implemented was not clear. 3. Will entities need to submit an all-inclusive MCR to "baseline" existing TFEs to the new process? LADWP requests that more detail be added to the proposed MCR submission; if this report is intended to supplant existing TFE submittals, it is important to note more details on the content of the report. **Comments regarding timing of MCR.** There is currently no identified timing requirement in Appendix 4D governing the submission of MCRs. PacifiCorp proposes that NERC add language to Appendix 4D expressly requiring that registered entities submit MCRs within 60 days following any identified Material Changes being completed. These comments appear to be in line with similar considerations being proposed by the industry via EEI. Concerning timing requirements for MCRs, SCE proposes that MCRs be generated by Registered Entities within 60 days following "Material Changes" being performed. Concerning timing requirements for MCRs: EEI proposes that MCRs be submitted by Responsible Entities before or up to 60 days after placing the "Material Changes" into service. CE states that Appendix 4D does not		

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	provide much detail in regards to the MCR submission. It does not provide a time limit on when a Responsible Entity must file the report or what happens if the Regional Entity has issues with the Material Change.		
Old sections 2.19 and 2.20 – The defined terms "Part A Required Information" and "Part B Required Information" were deleted to reflect the new format of the TFE request, which is consolidated into a single submittal.	No comment received.	N/A	N/A
Section 3.4 – This section was revised to reflect the new process for modifying an approved TFE through a MCR.	Concerning information requested, EEI notes that if strict compliance can be achieved, there is no need for an approval of a "Material Change" report. EEI suggests removal of: "or verifying Strict Compliance with the Applicable Requirement has been achieved." Concerning information requested in revised Section 3.4, SCE notes that if strict compliance can be achieved, there is no need for an approval of a "Material Change" report. SCE suggest removal of: "or verifying Strict Compliance with the Applicable Requirement has been achieved." TECO agrees with EEI comments in this Section. TECO also suggests being more specific regarding timing requirements for MCRs, frequency and number of days due after the change, and that it may create more reports if an amendment is required	No additional change.	The MCR is simply the vehicle to communicate changes to the Regional Entity. This is necessary to avoid the creation of yet another type of report to notify the Regional Entity that Strict Compliance was achieved. As noted, the MCR process is also streamlined.

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	to be filed with the MCR.		
Section 4.0 – In response to comments referenced elsewhere in this matrix, regarding the process for a MCR, the text of this section was reviewed throughout to reflect the fact that the process for a MCR is essentially identical to that of a TFE request.	See comments seeking clarification of the MCR, elsewhere in this matrix.	See revisions related to clarification of MCR process in attached redline.	N/A
Section 4.1 – This section was revised to reflect the possibility of submitting class-based TFE requests. In addition, language was deleted to allow Regional Entities to collaborate on approval of TFE requests for entities located in multiple Regional Entity footprints.	**Comments regarding class-based TFEs** NU - Class-Type TFEs: There should be more clarification provided regarding the substantive review for Class Type TFEs, and, at a minimum, a specific location in which the defined Class Type TFEs can be found. Concerning class-based categories of devices, Consumers Energy notes that NERC has had a similar term in previous versions of Appendix 4D, including the version currently in effect. However, such a list has never been available on NERC's web site. Consumer Energy believes it would be beneficial for NERC to develop such a list and seek industry feedback prior to finalizing. APM, Brazos Electric, and Sunflower Electric disagree with NERC removing the classifications from the Rules of Procedure and posting them on the NERC website. By posting them on the website, there is no official process for vetting changes to the classifications. If the classifications impact the TFE process, then they should be a part of	See revisions related to clarification of MCR process in attached redline.	Classes relate to similar types of devices. The current class types will be posted on the NERC website. The class types have been streamlined and include: (a) Network / Communication devices, (b) Server / workstation, (c) protective relay device, and (d) other. Classifying assets in these relative broad categories helps expedite the review process. It is necessary to allow flexibility with respect to the number and type of classes available. A change in the available classes would not trigger the need for a MCR. Therefore, there are no due process concerns associated with this aspect of the proposal. Vendor documentation is not required to substantiate a TFE request or MCR unless specifically requested by the Regional Entity.

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	Appendix 4D or Appendix 4D should outline how the changes to the classification will be vetted. It would be problematic if the ERO made changes to the classifications online and an entity did not file a MCR with those changes and the registered entity was then found in non-compliance. There are potential due process issues if the online classifications are modified without proper communication to the impacted registered entities. NERC's bylaws specify the procedure to be followed in making changes to NERC's Rules of Procedure. Such changes must be publicly posted for a 45-day comment period before being considered by the NERC Board of Trustees (Bylaws, Article XI, Section 2). APM, Brazos Electric, and Sunflower Electric recommend leaving the classifications in the Rules of Procedure Appendix 4D or modifying the appendix to clarify how changes will be vetted before any potential changes are made. EEI notes that Section 4.1 allows entities to request TFEs for class-based categories of devices. However, the rest of the appendix does not have any differences between class-based TFEs and TFEs that are not class based. Class-based TFEs could be used to further reduce the processing burden on all stakeholders. For example, EEI proposes that substantive review for class-based TFEs be eliminated. Entergy believes that for class based device categories with known technical limitations that will be maintained on the NERC website, supporting vendor documentation should not be required. Although BPA has no issues with the		

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	change, it would like to know what the classes will be. BPA requests clarification on what are the "class-based" categories. SCE suggests providing the location on NERC's website where a list of permissible class-based categories of devices can be found. SCE also suggests modifying the last sentence in the following manner: "In addition, a Responsible Entity may use one submission to request a TFE from the same Applicable Requirement for multiple, similar Covered Assets (either at the same location or at different locations within the geographic boundaries of a Regional Entity) on the same basis, with the same compensating measures and/or mitigating measures, and with the same proposed Expiration Date. TECO needs clarification on whether Regional Entities would be required to convert existing TFEs. PPL and MRONSRF - The proposed revisions are not clear on how a "class-based" TFE is specifically different from TFEs that are not class based. Class-based TFEs could be valuable if they reduced the effort and evidence needed to support the TFEs. As proposed, 4D is unclear on any differences for class-based TFEs. For substantive reviews per 5.2.1, Regional Entities "may conduct one or more physical inspections of the Covered Asset(s) and the related Facility(ies); may		

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	request additional information from the Responsible Entity; and may engage in discussions with the Responsible Entity concerning possible revisions to the TFE Request." If 5.2.1. is modified to reduce this burden for class-based TFEs, there is value in class-based TFEs.		
Sections 4.2 and 4.3 – These sections were revised to reflect the new format and Required Information associated with a TFE request. While the amount of information to be submitted is greatly reduced, the Regional Entity retains the ability to seek any other information that may be necessary or appropriate. In addition, the new language authorizes the Regional Entity to verify any information at a subsequent audit, spot check or other form of compliance monitoring. The TFE request would no longer involve a initial screen followed by a substantive review (former Parts A and B). Rather, the review would be performed on the basis of the consolidated TFE request, with substantiation to follow through a compliance monitoring and enforcement program	**Comments regarding typographical errors.** Regarding Section 4.2(e), AEP notes it should be "Rationale", not "Rational." In regards to Section 4.2(iii)(g), CE notes that the words "has" and "TFE" are reversed in the sentence. EEI also notes that in Section 4.2, part (iii), the words "has" and "TFE" are reversed in the sentence. BPA – 4.2e "Rational for the TFE …" "Rational" should be "Rationale". SCE also notes that in Section 4.2(e), the word "rationale" is misspelled and "Statement of Basis" should not be capitalized because it is not a defined term. SCE also believes that "has" and "TFE" should be switched around in Section 4.2(g). **Comments regarding Amendments vs. Material Changes.** NU - Amendments versus Material Changes: In section 4.2 where the form criteria are listed (items a-h), the list currently includes several items indicating there could be an	Please see clarifications in the attached redline including addition of "Expiration Date, if any" and other items to section 4.2 and clarification of other items to be included in the TFE request/MCR. Please also see sample TFE form at http://www.nerc.com/files/Proposed_TFE_Form_Jan2013.pdf. The noted typographical errors also have been corrected.	The intent, which was not fully captured in the redline posted on October 5, 2012, but has now been reflected in the new redlined Appendix 4D is that any changes to an existing TFE that must be reported to a Regional Entity will be reported through the MCR. As noted elsewhere, the MCR format and process, including review time, will follow that of a TFE request. The term amendment will be used to refer to the modification of a pending TFE request, which will not trigger a new review process. In addition, the list of Required Information in section 4.2 has been revised to include the types of information that will be required in most cases.

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(CMEP) process.	existing TFE already (items g and h). Would the MCR be used to update/amend a TFE as well, or would changes to the number of devices be made with a different form/manner? **Comments regarding adding Required Information to Section 4.2.** MRONSRF – On the surface, proposed revisions appear to reduce required information. However, later sections in the Appendix reference data that was deleted from existing 4D required information such as Expiration Date and Time Schedule. All information required for a TFE must be included in Section 4.2. Part A or B data is still required for Substantive Review or for reporting, include it the Required Information list. Changes in 4D to Required Information and Registered Entity reporting must comprehend and encompass all the data required from the Registered Entities to support NERC's filing to FERC. Regarding Section 4.2, Consumers Energy believes "Device Count" and "Device Type" fields should be required as well. Concerning information requested in Section 4.2, EEI notes that the proposed revisions appear to significantly reduce the "Required Information" for a TFE. However, later sections reference data that		

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	was deleted from the existing 4D Required Information (e.g., Expiration Date and time schedule.) If this information is still required, it should be listed in section 4.2 to eliminate confusion and inconsistency. Concerning "Time Schedule": EEI observes that the proposed TFE submission process does not require identification of a Time schedule for a TFE Request; however 6.1, 6.211, 7.2.112, 8.113 refer to Time schedule information. EEI proposes that all references to Time schedule be eliminated. Concerning "Expiration Date": EEI observes that Expiration Date was removed from the Required Information, but is mentioned throughout the Appendix: 2.13, 2.17, 3.4, 4.1, 6.2, 7.2.1, 8.2, 9.3, and 13.1. EEI proposes that Section 4.2 be modified to add "Expiration Date, if applicable" to the list of TFE Required Information or delete Expiration Date references in the process. Concerning "Time Schedule", SCE observes that the proposed TFE submission process (pg. 7) does not require identification of a Time schedule for a TFE Request, however 6.1, 6.2 (pg. 18), 7.2.1 (pg. 19), and 8.1 (page 20) refer to Time schedule information. SCE proposes that all references to Time schedule be eliminated. Concerning "Expiration Date", SCE		

Change proposed by NERC	Comment received	Outcome	Justification/Notes
	observes that Expiration Date was removed from the Required Information but is mentioned throughout the Appendix: 2.13, 2.17, 3.4, 4.1, 6.2, 7.2.1, 8.2, 9.3, and 13.1. SCE proposes that section 4.2 be modified to add Expiration Date (while still allowing for open ended) to the list of TFE Required Information or delete Expiration Date references in the process. GSOC finds that Section 4.2 TFE Request shall include the "proposed expiration date." BPA also suggests including the following information: Device description; Device count; Device location; Proposed Expiration date or Open Ended; and Whether the TFE is related to a self-certification or self-report. PPL - The proposed revisions significantly change the "Required Information" for a TFE. At first look, it appears these changes significantly reduce the information required for a TFE. However, later sections reference data that was deleted from the existing Appendix 4D Required Information (for example, Expiration Date and time schedule.) If this information is still required, it must be listed in Section 4.2 to eliminate confusion and inconsistency. Additional adjustments are also needed to some of the proposed Required Information in Section 4.2.		

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	PPL and MRONSRF - Expiration Date was removed from the Required Information but is mentioned throughout the Appendix: 2.13, 2.17, 3.4, 4.1, 6.2, 7.2.1, 8.2, 9.3, 13.1. Either add Expiration Date (allowing still for open ended) to the list of TFE Required Information in 4.2 or delete Expiration Date references. PPL and MRONSRF - 6.1, 6.2, 7.2.1, 8.1 "in accordance with the time schedule(s) set forth, in the approved TFE." The proposed revisions deleted "time schedules" as Required Information for a TFE. Delete all references to time schedules. PPL - If Expiration Date (see above) is retained and added to Required Information, add time schedules to Required Information only for TFEs that are not open ended. **Comments regarding removing or revising Required Information in section 4.2.** Concerning information requested in Section 4.2 (c), EEI proposes that the "date of installation" information called for in section 4.2 (c) be eliminated. Reasons for this recommendation include: a. This is a new data/information request. This is not present in the existing TFE process; b. This information may not be known at the time of a request for the TFE; c. Completing, then updating this information significantly increases the		

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	administrative burden and overhead of the TFE process yet does nothing to enhance the reliability of the BES. However, if this recommendation is not followed, EEI propose that “date of installation” be defined to refer to the date the equipment or device is placed into service. Regarding Section 4.2, ERCOT requests clarification on “Device ID.” Please clarify if this is system name, make/model information, or other information. ERCOT also suggests changing “Date of installation” to “Compliance Date”. If an asset is subject to the CIP standards due to a change in reliability standard requirements or a change in the method of identifying assets, the installation date is not the relevant date. Rather, it is the effective date of the change in methodology that brought the asset into CIP scope. Additionally, assets may be installed but not relevant for CIP purposes until some future date. Again, in that situation, the installation date is not relevant. BPA– 4.2a: “Device ID” The term “Device ID” is not defined. Please clarify. 4.2c: “Date of Installation” There could be multiple dates of installation. BPA suggests “Date or Dates of Installation.” 4.2g: “Whether the TFE has been previously approved?” Sections 3.4 and 6.6 state the appropriate method for modifying an approved		

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	TFE is to submit a MCR. In that case, all TFE submissions would involve only unapproved TFEs. Therefore, this entry is unneeded. 4.2h: "TFE ID, if known" The TFE ID is assigned upon submission of the TFE. It would be known if this submission is for the amendment of an unapproved TFE (as described in Section 7.1). Otherwise, it wouldn't exist. BPA suggests making that explicitly clear. Regarding Section 4.2, TECO agrees with EEI proposal/comments. Additionally, TECO requests clarification as to whether the submitted compensating measures are the short version (Part A) or the substantive version, and clarification as to what additional info and/or action the Entity needs to take is required to show demonstration of progress toward strict compliance. Regarding Section 4.2, NextEra suggests providing a definition of Device ID since this could be inconsistently defined field for Responsible Entity's to fill out. If defining this field is not an option, suggest removing this field completely as it does not assist in determining which covered assets are in scope of the TFE. NextEra also suggests changing "Date of installation" to "Date of installation or compliance date." If it is an asset that has been in service for a while and then becomes a Cyber Asset used to support NERC CIP compliance the compliance date		

Change proposed by NERC	Comment received	Outcome	Justification/Notes
	is the key date, not the installation date. Regarding Section 4.2, SCE notes that the proposed revisions appear to significantly reduce the "Required Information" for a TFE. However, later sections reference data that was deleted from the existing 4D Required Information (for example, Expiration Date and time schedule.) If this information is still required, it should be listed in 4.2 to eliminate confusion and inconsistency. In addition, SCE proposes that the information called for be re-considered for the following reasons: a. This information may not be known at the time of a request for the TFE; b. Also, completing, then updating this information significantly increases the administrative burden and overhead of the TFE process yet does nothing to enhance the reliability of the BES. Regarding Section 4.2(c), SCE also suggests that "Date of Installation" should be replaced with "In-service Date" or something similar to reflect the date a device is actually up and running. A device could be installed and not actually be in-service. In regards to Section 4.3, Dominion proposes that part 'g' of the Required Information for a TFE Request should be rewritten as follows, "Whether the TFE has been previously approved". PPL and MRONSRF - In Section 4.2 and others, Appendix 4D leaves		

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	Regional Entity discretion on additional data too wide open. Registered Entities must have clarity on what is expected to meet compliance and reporting upfront and not retrospectively. If more of the current Part A or B data is still required for substantive review or for reporting, include it the Required Information list. Do a gap analysis to ensure all needed data is listed. PPL and MRONSRF also propose that no amendment be required if only the TFE device count changes. As proposed, decreases do not require amendments, but increases do. Experience shows device counts fluctuate up and down constantly. This creates a reporting and processing burden for little to no reliability benefit. The required content for the FERC report to NERC lists "numbers of unique Covered Assets for which TFEs have been approved." Does this mean the number when approved and/or amended or the number at June 30? If the June 30 number is needed for FERC, entities could provide the TFE ID and count only once a year and no approval/disapproval processing should be required. File amendments if the other Required Information changes. PPL and MRONSRF – With respect to 4.2.a, retain original: "Number of Covered Assets for which the TFE is requested." If lists of Covered Assets with device IDs are required, it should be included in the Required		

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	Information. PPL - With respect to 4.2.c, do not require installation date. Retain the 4D 4.3.14. acknowledgement that compensating measures "have been fully implemented at the time of the TFE Request" submission. MRONSRF – With respect to 4.2.c, Delete. This is not included in the current TFEs, may not be known at the time of the TFE request and significantly increases administrative documentation without reliability benefit. PPL and MRONSRF - With respect to 4.2.e, explicitly refer to 3.1 (i) – (vi) and use the 3.0 title "Basis for Approval." With respect to 4.2.f, retain existing: Whether the TFE Request is an original or an amendment. **Comments regarding MCR process.** Regarding Section 4.2 item c, the date of installation, as Required Information for filing a TFE, Entergy would like to know how it this will affect an Entity's ability to preemptively file a TFE. For example, Entergy files a TFE Request prior to devices actually being placed into the production environment in accordance with the current NERC Rules of Procedure. During the Change Management process a tentative installation date is proposed, however the realities of Change Management are that production does not always occur		

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	exactly when expected. As the TFE process is currently, no installation date is required. There will be major challenges with filing a TFE Request prior to production (as required) with an actual installation date. If the installation date is different slightly by what is listed in the new TFE Request, would this then require a MCR with the actual date of installation if the expected date noted in the pre-emptive TFE Request is different? Regarding Section 4.2 items g and h, Entergy believes these items would be better found on a MCR, as opposed to a TFE request, with the understanding that a TFE Request would be submitted, with changes documented in a MCR, it seems that these items would be null, and thus invaluable to be documented on a TFE Request. **Comments regarding Class-based TFE request.** Dominion also finds that the part of the Required Information doesn't allow for the identification of class-based devices for which a single TFE may be applicable.		
Section 4.4.1 – This section was revised to reflect the elimination of Part B of the TFE Request.	TECO is concerned regarding the confidentiality of the information submitted now that Parts A & B will be combined. TECO would likely need to redact information.	No additional change.	All TFE-related information will be protected pursuant to the NERC Rules of Procedure.
Section 4.5 – This section as revised to reflect the elimination of the initial screening (Part A) process.	Concerning Section 4.5 Submission of TFE Request in Advance of Compliant Date, EEI recommends elimination of the text below, as it is	In response to comments, this section was deleted.	This section was eliminated because it was not necessary. The extent of the safe-harbor protection is already defined in Section 5.3, which provides an incentive for the filing of a TFE 60 days prior to the registered entity's Compliant Date. That provision has not been substantively revised so

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	no longer relevant: "However, if a Responsible Entity whose Compliant Date for an Applicable Requirement was on or before December 31, 2009, submits a TFE Request for the Applicable Requirement by January 31, 2010 (either pursuant to this Appendix or pursuant to NERC Compliance Process Bulletin #2009-007 and Attachments 1 and 2 to that Bulletin), the Compliant Date will be deemed to be the date of submission of the TFE Request for purposes of Section 5.3 of this Appendix." TECO agrees with EEI recommendation in Section 4.5. In addition, TECO is concerned that advance notice requirements allow no provision for emergency changes that may be necessary to provide BES reliability and that the Section may create more reports if an amendment is required to be filed with the MCR. SCE recommends elimination of the text below, as it is no longer relevant : "However, if a Responsible Entity whose Compliant Date for an Applicable Requirement was on or before December 31, 2009, submits a TFE Request for the Applicable Requirement by January 31, 2010 (either pursuant to this Appendix or pursuant to NERC Compliance Process Bulletin #2009-007 and Attachments 1 and 2 to that Bulletin), the Compliant Date will be deemed to be the date of submission of the TFE Request for		registered entities remain at risk for a finding of a possible violation if TFE requests are not timely submitted. Section 4.5 contained an administrative requirement for submitting TFE requests within a specified timeframe that is not needed in light of the provisions of Section 5.3. As a result, the timeframe for submitting a TFE request is not being modified from the currently effective Appendix 4D. The proposed revisions are intended to be procedural in nature and not affect a Responsible Entity's' obligation to comply with applicable Reliability Standards or seek a timely TFE. In many cases, Regional Entities have found that late submittal of TFEs posed a minimal risk to the reliability of the BPS and such issues were addressed through FFTs or other appropriate methods. The proposed revisions to Appendix 4D do not affect the availability of this type of treatment when appropriate.

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	purposes of Section 5.3 of this Appendix." SPP finds that requiring a TFE to be submitted 60 days prior to a Compliance Date for a requirement is problematic. Many Responsible Entities work with vendors to provide solutions and often cannot evaluate an implementation for strict compliance with enough time to meet this window. Recommend a different window for TFE that acknowledge this. PPL and MRONSRF - Experience shows that not all device limitations are discovered until pre-implementation, implementation and post-implementation testing is complete. Sixty days in advance does not accommodate when, despite responsible due diligence, issues come to light during this testing. Proposed 4D 4.5 should be revised to include provision for safe harbor if the device limitations for strict compliance were discovered during implementation. The benefit to reliability is if compensating measures are installed pre-implementation as prevention in case limitations are discovered during implementation, not if the paperwork was filed pre-implementation. MRONSRF - 4.5 references Process Bulletin 2009-007 and Jan. 31, 2010. It does not reference Process Bulletin 2010-001 and April 30, 2010. Include both or delete the related content in 4.5 and rely on		

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	the Process Bulletins historically if no entities need either date for future compliance monitoring and/or enforcement.		
Sections 5.0 and 5.1 – The headings of the sections were modified to reflect the elimination of the screening process and consequent acceptance or rejection.	No comment received.	In response to comments seeking clarification on the process for submitting the MCR, further revisions were made to Section 5.0 to reflect the fact that the process for the MCR is essentially identical to that of a TFE request.	N/A
Sections 5.1.1, 5.1.3-5.1.7 – These sections were revised to reflect the elimination of the Part A submittal as well as the streamlined information requirements and consolidated review and approval process for TFE requests.	Concerning Section 5.1.1, EEI suggests that upon completion by the Regional Entity of items (i) and (ii) as described in Section 5.1.1, the Regional Entity should notify the Responsible Entity that this initial review has been completed. Additionally, there should be a 60-day time limit from receipt of the TFE request for the Regional Entity to perform this initial review. In regards to Section 5.1.1, CE states that upon completion by the Regional Entity of items (i) and (ii) as described in this section, the Regional Entity should notify the Responsible Entity that this initial review has been completed. CE also states that there should be a 60-day time limit from receipt of the TFE request for the Regional Entity to perform this initial review. Entergy echoes both of CE's comments regarding Section 5.1.1. Regarding Section 5.1.1, SCE notes that upon completion by the Regional Entity of items (i) and (ii) as	Please see clarifications to sections 5.1 and 5.2 in attached redline.	The intermediate notifications proposed by some entities are not appropriate in the context of a streamlined review process. The confusion appears to arise from the fact that the references to an "initial" review that would be followed by a "substantive" review were inadvertently left in. The proposal contemplates a single, 60-day review process in which the Responsible Entity provides the information required in section 4.2 (as revised in response to the comments received) followed by approval or disapproval of the TFE request or MCR. No substantive review is performed until such time as the Regional Entity either schedules a separate monitoring method or reviews the information in a previously scheduled monitoring method. Notice requirements, including timing, will vary in accordance with the monitoring method selected but will follow the requirements of the CMEP. The review process will be completed within 60 days in most cases, but the Regional Entity has the ability to extend this timeframe if necessary. This flexibility is needed because, while the majority of TFE requests and MCRs can be reviewed within 60 days under the new process, the rules cannot exclude the possibility that a novel request or report may be filed in the future and require more time.

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	described in this section, the Regional Entity should notify the Responsible Entity that this initial review has been completed. SCE states that there should be a 60-day time limit from receipt of the TFE request for the Regional Entity to perform this initial review. MRONSRF - As revised, the Registered Entity has no information from the Regional Entity until the Substantive Review. Upon completion by the Regional Entity of items (i) and (ii) as described in Section 5.1.1., the Regional Entity should notify the Responsible Entity that this initial review has been completed and provide the unique identifier.		
Section 5.2.1 – This section was revised to reflect the elimination of the Part B submittal. In addition, the reference to Data Request was eliminated as unnecessary since CMEP processes rather than Data Requests are generally used in connection with TFE reviews.	EEI's initial understanding of the Proposed Revisions to the TFE request process was that the new 60 day review of a TFE request would continue to allow Regional Entities to perform substantive reviews of TFE requests. If the TFE review process allows for substantive reviews, EEI believes that it is appropriate for the Regional Entity to provide adequate notice of their intent to perform substantive reviews of TFE requests and recommend inserting the following language into section 5.2.1: If a Regional Entity intends to perform substantive reviews of TFE requests on an annual or regularly scheduled basis, the Regional Entity should provide 60 days notice of their intent to perform the	Please see clarifications to sections 5.1 and 5.2 in attached redline.	In the context of NERC's efforts to reduce the administrative burden for TFE requests while maintaining reliability, a substantive review is not a part of the 60-day review process for a TFE request or MCR. As discussed above, any verification of information may be performed at a subsequent CMEP activity such as an audit or spot check, pursuant to the CMEP provisions.

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	substantive review. The substantive review as stated in 5.2.1 will be conducted in "accordance with the established compliance monitoring processes under the CMEP, such as a Compliance Audit or Spot Check." While timing may occasionally coincide with a Compliance Audit under the CMEP, it is more likely that the majority of TFE reviews will not fall within a Compliance Audit timeframe to complete substantive review for approval or disapproval. Review of the CMEP steps for Spot Checks and the other CMEP monitoring processes also do not align well with TFE substantive review needs. Consequently, EEI recommends striking references to the CMEP in the description of substantive review and simply stating the Regional Entity must complete the substantive review within 60 days. However, based on a conversation with NERC staff, it is now EEI's understanding that section 5.2.1 and 5.2.2 will be further edited to remove the references to substantive reviews and clarify that the new review process for TFE requests is 60 days. Based on this conversation, it is our understanding that in NERC's efforts to reduce the administrative burden for TFE requests while maintaining reliability, a substantive review is no longer a part of the 60 day review process for a TFE request. If this understanding is correct then the above recommendations are no longer applicable. SCE recognizes the authority of		

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	Regional Entities to perform Substantive Reviews of TFE requests. SCE believes that it is appropriate for the Regional Entity to provide adequate notice of their intent to perform Substantive Reviews of TFE requests. SCE suggest inserting the following language into section 5.2.1: "If a Regional Entity intends to perform Substantive Reviews of TFE requests on an annual or regularly scheduled basis, the Regional Entity should provide 60 days notice of their intent to perform the Substantive Review." SCE also suggesting modifying the first sentence in the following manner: "The Regional Entity shall conduct a substantive review of a TFE Request to determine if it should be approved, or disapproved, in accordance with Section 3.1 of this Appendix~~, or disapproved~~." MRONSRF - Regional Entities have authority to perform Substantive Reviews of TFE requests. It is reasonable for the Regional Entity to provide adequate notice of their intent to perform Substantive Reviews of TFE requests. Depending on the outcome above, if the process is to perform Substantive Reviews of TFE requests on an annual or regularly scheduled basis, the Regional Entity should provide 60 days notice of their intent to perform the Substantive Review.		

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Section 5.2.2 – This section was revised to eliminate a cross reference to a deleted section.	In addition to its comment on Section 5.2.1, EEI also notes that Section 5.2.2 also refers to substantive reviews, requiring the Regional Entity "to complete its substantive review of the TFE request and make its determination of whether the TFE Request is approved or disapproved, within one (1) year after receipt of the TFE Request." This language appears contradictory to page 2 of the posted Summary of Proposed Revisions on which states "the proposal shortens the overall processing time for TFE requests (from approximately 13 months to 4 months), including the processing time for amending a pending or existing TFE request. "The principal revision webinar slide also cites shortening of the overall processing time "changes to a pending TFE request are allowed during the 60-day review period without restarting the review process." The webinar discussion noted an intent that all time references were to be 60 days. However, based on a conversation with NERC staff, it is now our understanding that section 5.2.1 and 5.2.2 will be further edited to remove the references to substantive reviews and clarify that the new However, based on a conversation with NERC staff, it is now our understanding that section 5.2.1 and 5.2.2 will be further edited to remove the references to substantive reviews and clarify that the new review process for TFE requests is 60 days. Based on this conversation, it is our	See clarification in attached redline.	As noted in the October 31, 2012 webinar, the review period consists of 60 days, not one year. See also above regarding clarification of the scope of review. It is expected that most TFE requests and MCRs will be approved prior to any verification. However, entities should note that a TFE may be terminated in the event a subsequent verification uncovers a material misrepresentation pursuant to section 9.1.

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	understanding that in NERC's efforts to reduce the administrative burden for TFE requests while maintaining reliability, a substantive review is no longer a part of the 60 day review process for a TFE request. If this understanding is correct then the above recommendations are no longer applicable. TECO agrees with EEI comments in Section [5.2.2] In addition, TECO requests additional clarification as follow: Is a substantive review required and within what timeframe?; How it be noted in the Compliance Tracking System (i.e., "pending review")? BPA notes that, as noted in the webinar of Oct. 31, "one year" needs to be changed to "60 days". MRONSRF – section 5.2.2 States a "TFE Request is approved or disapproved, within one (1) year after receipt of the TFE Request." This appears contradictory to page 2 of the posted Summary of Proposed Revisions which states "the proposal shortens the overall processing time for TFE requests (from approximately 13 months to 4 months), including the processing time for amending a pending or existing TFE request. " The principal revision webinar slide also cites shortening of the overall processing time, "Changes to a pending TFE request are allowed during the 60-day review period without restarting the review process. " The webinar discussion noted an intent		

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	that all time references were to be 60 days. If the intent, as stated in the summary and webinar, is to eliminate the one year review period and shorten it to 60 days, then 5.2.2 requires revision. However, 5.2.1 requires Substantive Reviews to approve or disapprove a TFE. The Substantive Review as stated in 5.2.1 will be conducted in "accordance with the established compliance monitoring processes under the CMEP, such as a Compliance Audit or Spot Check." While timing may occasionally coincide with a Compliance Audit under the CMEP, it is more likely that the majority of TFE reviews will not fall within a Compliance Audit timeframe to complete substantive Review for approval or disapproval. Review of the CMEP steps for Spot Checks and the other CMEP monitoring processes also do not align well with TFE Substantive Review needs. Consequently, we recommend striking references to the CMEP in the description of Substantive Review and simply stating the Regional Entity must complete the Substantive Review within 60 days.		
Section 5.2.3 – This section was revised to reflect that a TFE request can be approved in part.	AEP asks what does it mean to approve or disapprove a TFE "in part"? Furthermore, what is the process for resubmitting a TFE that has only been approved "in part"? AEP recommends striking any language regarding the approval or disapproval of a TFE in part.	No additional change.	The approval of a TFE in part refers to the approval with respect to some, but not all of the devices included. This is intended, for example, to allow the Regional Entity to approve a TFE request with respect to the portion of the request that is ready to be approved while continuing to work with the Responsible Entity on those aspects that require additional work. It is also intended to apply in circumstances where not all of the devices included would qualify. Rather than requiring that the Registered Entity disapprove the entire TFE request, the appropriate part of the request may be approved.

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	SCE suggests providing clarification on what would be the next step for the Regional Entity and/or Responsible Entity if a TFE were to be approved "in part". Also, SCE asks why is the word "may" replacing "must either"? If the Regional Entity doesn't approved or disapprove the TFE, what else is it going to do? TECO is concerned that any revisions to the existing TFE process should specifically address requirements for Approved, or Pending TFEs that were in place or in process before proposed revisions take effect.		
Section 5.2.4 - This section was revised to reflect the fact that the process for a MCR is essentially identical to that of a TFE request.	N/A	N/A	N/A
Section 5.2.5 – This section was revised to reflect that the primary responsibility for supporting a TFE request rests with the Responsible Entity. While the Regional Entities could discuss potential revisions with the Responsible Entity, the Responsible Entity is the entity with the information needed to develop any necessary revisions.	**Comments regarding review process.** TAPS and APPA find the proposed revisions would eliminate important text from Section 5.2.5 that creates the opportunity for Regional Entities, when disapproving a TFE request, to state any revisions to the TFE request that would result in its approval. While TAPS and APPA agree that the primary responsibility for supporting a TFE request rests with the Registered Entity, the existing process in Section 5.2.5 facilitates a dialogue between Registered Entities and Regional	In response to comments, language allowing the Regional Entity to provide substantive feedback in connection with a disapproval was reinstated.	The review process for either a TFE request or the MCR will be performed within 60 days, unless the Registered Entity determines that additional time is necessary. It is expected that the majority of TFE requests and MCRs will be processed within the 60-day timeframe because experience has shown that most of such items are routine and present similar issues. However, there is a need for flexibility in the event a novel issue arises. During the 60-day review period, a Responsible Entity is able to supplement or modify its submittal as necessary. The Responsible Entity should not wait until the end of the period to provide additional information or modifications because that may prevent the request from being approved. A modification will not restart the 60-day clock for review, unless the Regional Entity deems necessary.

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	Entities that can reduce unnecessary time delays and prevent multiple attempts to get TFE requests approved. TAPS and APPA therefore suggest that NERC retain all the language in Section 5.2.5. EEI notes that the proposed draft appears to eliminate an important series of due process steps associated with the submission and review of TFEs. EEI believe that it is important to retain most of the existing language in order to have a process to facilitate communication between Regional Entities and Responsible Entities. EEI suggest retaining the following language: In its notice disapproving a TFE Request, the Regional Entity may also, but is not required to, state any revisions to the TFE Request the Regional Entity has identified, based on its review of the TFE Request, that, if made by the Responsible Entity, would result in approval of the TFE Request. Such revisions may include, but are not limited to, changes to the Responsible Entity's proposed (i) compensating measures and/or mitigating measures, ~~(ii) implementation schedules~~, or (ii) Expiration Date. If the Responsible Entity submits an amended TFE Request to the Regional Entity incorporating, to the Regional Entity's satisfaction, the revisions to the TFE Request set forth in the notice of disapproval, then the Regional Entity shall issue a notice, in accordance with Section 5.2.4, approving the revised TFE		

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	Request. TECO agrees with EEI comments in Section 5.2.5. SCE notes that the proposed draft appears to eliminate an important series of due process steps associated with the submission and review of TFEs. SCE believes that it is important to retain most of the existing language in order to have a process to facilitate communication between Regional Entities and Responsible Entities. SCE suggests retaining the following language: "In its notice disapproving a TFE Request, the Regional Entity may also, but is not required to, state any revisions to the TFE Request the Regional Entity has identified, based on its review of the TFE Request, that, if made by the Responsible Entity, would result in approval of the TFE Request. Such revisions may include, but are not limited to, changes to the Responsible Entity's proposed (i) compensating measures and/or mitigating measures, ~~(ii) implementation schedules,~~ or (iii) Expiration Date. If the Responsible Entity submits an amended TFE Request to the Regional Entity incorporating, to the Regional Entity's satisfaction, the revisions to the TFE Request set forth in the notice of disapproval, then the Regional Entity shall issue a notice, in accordance with Section 5.2.4, approving the revised TFE Request." Dominion finds that removing in its		

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	entirety the language allowing a Registered Entity to revise a disapproved TFE Request leaves no mechanism in the ROP allowing a TFE Request to be revised and resubmitted after the initial disapproval. A mechanism should be provided in the ROP to allow TFE Requests to be corrected. Without such a mechanism, a Responsible Entity that makes an administrative error on a TFE Request may find it has to self-report for the period of time needed to identify the error and correct the TFE Request. It's unclear in the ROP how the Responsible Entity may find safe-harbor to ensure an appropriate time period is applied to the TFE once it becomes approved. Entergy echoes Dominion's comments on Section 5.2.5. BPA notes that the portions referring to submitting an amended TFE after disapproval have been removed from 5.2.5, but such an amendment is still included in 5.2.6. BPA suggests restoring the deleted sections in 5.2.5. MRONSRF - Revisions strike important steps to efficiently address issues and afford due process. Retain the struck text, except for the reference to "(ii) implementation schedules".		
Section 5.2.6 and 5.2.7 – These sections were revised to reflect the fact that the process for a MCR is essentially identical to	Dominion notes that the third sentence includes the following text, "…unless the Responsible Entity (i) has submitted an amended TFE Request on accordance with	Revised to correct cross-reference and to clarify MCR process.	N/A

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that of a TFE request.	Section 5.2.5…"; however, the corresponding text in Section 5.2.5 has been removed inappropriately as noted above. There is no mechanism in the ROP, as updated, for revising a 'disapproved TFE Request".		
Sections 5.2.8 and 5.2.9 – These sections were revised to reflect the consolidation of the review process and the elimination of initial screening phase, in which the TFE request could be "rejected."	No comment received.	N/A	This section was also subsequently reviewed to eliminate cross references to two deleted sections.
Section 5.3 – This section was revised to reflect the consolidation of the review process and the elimination of initial screening phase, in which the TFE request was "accepted" for further review and approval or "rejected."	SPP asks what state is a Responsible Entity in between the submission of the TFE and the "sixty (60) calendar days after submission of the TFE request"? Does the safe harbor apply in that time? The language which was stricken provides more clarity. If the safe harbor begins on "the date of the Regional Entity's notice that the TFE Request is submitted as complete" this would give a Responsible Entity a clearer indication of their status while the TFE is being reviewed. Concerning Section 5.3(i), EEI observes that the existing 5.3 (i) is principally concerned with the timing of submission of TFE requests, rather than the reliability benefits of timely implementation of compensating measures for components that are unable to perform using a "strict compliance" measure. EEI proposes that (i) be revised to: (i) the earlier of (A) the date of the Regional Entity's notice that the TFE Request is accepted as	No additional change.	The proposed revisions are not intended to modify existing rules regarding safe-harbor, which begin, under the current FERC-approved Appendix 4D, 60 days after the submittal of the TFE, which in turn is designed to coincide with (or precede) the start of the entity's compliance obligations under section 4.5. As noted above, the timeframe for submitting a TFE request is not being modified from the currently effective Appendix 4D. The proposed revisions are intended to be procedural in nature and not affect a Responsible Entity's' obligation to comply with applicable Reliability Standards or seek a timely TFE. In many cases, Regional Entities have found that late submittal of TFEs posed a minimal risk to the reliability of the BPS and such issues were addressed through FFTs or other appropriate methods. The proposed revisions to Appendix 4D do not affect this type of treatment when appropriate.

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	complete and (B) the date that compensating measures associated with the TFE request were implemented. This revision also corresponds to comment 7 [regarding section 5.1.1]which suggests that the Regional Entities should confirm receipt of complete submissions. TECO agrees with EEI comments in Section 5.3(i). SCE observes that the existing section 5.3.1 (i) is principally concerned with the timing of submission of TFE requests, rather than the timely implementation of compensating measures for components that are unable to perform using a "strict compliance" measure. SCE proposes that (i) be revised to: "(i) the earlier of (A) the date of the Regional Entity's notice that the TFE Request is accepted as complete and (B) the date that compensating measures are implemented associated with a TFE request." MRONSRF - Safe harbor should be based on the reliability benefits of implemented compensating and/or mitigating measures, not on the timing of filing paper work. Proposed 4D 5.3 (i) should be revised to include provision for safe harbor if the device limitations for strict compliance were discovered during implementation. The benefit to reliability: • compensating measures are installed pre-implementation as		

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	prevention in case limitations are discovered during implementation • not if the paperwork was filed pre-implementation (violations should not be based on paperwork). Delete the 60-day advance notice in 4.5. See 5.3. (i). Revise (i) to: (i) the earlier of (A) the date of the Regional Entity's notice that the TFE Request is accepted as complete or (B) the date that compensating measures associated with the TFE request were implemented.		
Section 6.0 – In response to comments, further revisions were made throughout this section to reflect the fact that the process for a MCR is essentially identical to that of a TFE request.	N/A	N/A	N/A
Section 6.2 – This section was modified to recognize that the majority of the TFE requests do not have Expiration Dates. Experience has shown that most TFEs relate to network devices and other equipment for which vendors are not pursuing versions that would allow Strict Compliance with NERC Reliability Standards and consequently, a need for an open-ended TFE exists in most cases.	TECO agrees with EEI comments in Section 6.2. In addition, TECO is concerned that there should be some consistency throughout the Appendix 4D addressing "Time Scheduling" and "Expiration Date." [EEI comment referenced in section 4.2.] Southern Company appreciates the opportunity to briefly provide comments on the Proposed Revisions to NERC Rules of Procedure, Appendix 4D. In general, Southern Company is supportive of EEI comments submitted to NERC for their review. In addition to the EEI comments, Southern would like to add that there remains a need for	Please see clarifications to the redline adding "Expiration Date, if any" and other items to the "Required Information" in section 4.2.	As noted in the documents submitted with the proposed revisions and in outreach opportunities, a TFE request may omit an Expiration Date if the TFE request is intended to be open-ended (see also section 3.4). The Expiration Date will be added to the Required Information section.

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	"open ended" TFEs with no determined "expiration date" at the time a TFE is submitted and approved. Assuming an "expiration date" is required or can be determined by the Responsible Entity, the TFE process needs to allow for the assignment of an "expiration date" at any point in the that process, allow for "open ended" expiration dates, and allow for a known "expiration date" to be extended or to transition to "open ended". In our experience, the facts and technology underlying the rationale for a TFE evolve over time and flexibility is required as to when a TFE will or will not be expired.		
Section 6.3 and 6.4 – These sections were deleted to eliminate the requirements for quarterly reports to the Regional Entity. Experience has demonstrated that these are not necessary to maintain reliability so long as the TFE remains unchanged. Under section 13.5, however, both Regional Entities and Responsible Entities remain under the obligation to provide any information deemed necessary for NERC to fulfill its reporting obligations to FERC, and Responsible Entities have the obligation to notify Regional Entities in any Material Changes to TFEs.	TECO states that it has similar concerns as stated earlier regarding "MCR" vs. "Amendment."	No additional change.	See discussion above.
Section 6.5 – This section was modified to eliminate	NU - MCR: The description of the MCR (MCR) in the current draft	No additional change to this section but see additional detail added in Section 4.0.	Clarification regarding the MCR process has been added to section 4.0.

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the requirement for an annual report to the Regional Entity and instead require a MCR that would be submitted when an amendment to the initial TFE request occurs. Under section 13.5, both Regional Entities and Responsible Entities remain under the obligation to provide any information deemed necessary for NERC to fulfill its reporting obligations to FERC.	(Section 6.5/6.6) gives rise to questions regarding the applicability of the MCR. For example, if a Registered Entity has multiple devices with the same mitigating measures in an existing TFE for a single requirement, would an MCR be needed if the Registered Entity needed to add a similar device with the same mitigating measures for the same requirement? CE states that Appendix 4D does not provide much detail in regards to the MCR submission. It does not provide a time limit on when a Responsible Entity must file the report or what happens if the Regional Entity has issues with the Material Change. Entergy echoes CE's comment. If changes to device counts are defined as a Material Change, NextEra suggests requiring that the MCR be filed on a periodic basis. Given the continuous state of improvement by Registered Entities, increases or decreases in device counts could happen regularly. In this scenario the administrative burden would be greatly increased. BPA suggests that "…shall submit a report…" in the first sentence be changed to "…shall submit a MCR…". This provides consistency with the last sentence of Section 6.5, which uses the term "MCR".		The Regional Entities need information on the number of devices affected by a TFE request. This is part of the evaluation of the TFE. Additional devices can be easily included through the MCR, which would add one or more rows to an entity's TFE spreadsheet. The review process in that case should be equally simple. However, the Regional Entities need to retain the ability to receive the MCR and determine that in fact the devices added are identical and the same mitigating measures already in place are appropriate. Note that a decrease in device count would not require a MCR. Similarly, Regional Entities need information on changes to the expiration date for TFEs. Note that an expiration date is not required as the TFE can be open ended. However, if one is provided, a change to the expiration date must be reported through the MCR. The review process for the MCR is essentially identical to that of the initial TFE request and any necessary substantive review or verification may be performed after approval of the MCR through a CMEP method.
Section 6.6 – This section was modified to reflect the requirement of a MCR and	**Comments regarding signature of senior manager or delegate.**	This section and sections 6.6, 6.7 and 6.9 were deleted because the process for submitting the MCR was addressed in Section 4.0 and 5.0 and these became unnecessary and duplicative. The requirement regarding a	The signature of the senior manager can be electronic but it is necessary to demonstrate that the management of the entity is aware of and involved in the process. The deletion of the equivalent requirement of management

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the elimination of the quarterly and annual reports to the Regional Entity.	EEI observes that the proposed TFE submission process does not require a Senior Manager or Delegate signature for initial submission of a TFE request; EEI think that this is a good process improvement. Consistent with a move toward reduction in administrative overhead that does not serve to enhance reliability, and with the recognition that "At the discretion of the Regional Entity, information may be verified at a subsequent audit or spot-check or other form of monitoring." EEI proposes that section 6.6 be eliminated. SCE observes that the proposed TFE submission process does not require a Senior Manager or Delegate signature for initial submission of a TFE request; SCE states that this is a good process improvement. Consistent with a move toward reduction in administrative overhead that does not serve to enhance reliability, and with the recognition that "At the discretion of the Regional Entity, information may be verified at a subsequent audit or spot-check or other form of monitoring." SCE proposes that section 6.6 be eliminated. ERCOT requests that "signed and dated" be replaced with "approved" to allow for electronic processing means such as portal submission. Dominion states that this section should be removed in its entirety as the requirement to obtain Senior Manager or Delegate approval for	signature of a senior manager or delegate was maintained.	signature for the initial submission of a TFE request was in error and will be corrected in Section 4.0. Contrary to what was pointed out by a few commenters, FERC is not moving away from the requirement to have senior management involved in reliability issues. In the FFT order, referenced by some commenters, FERC imposed more significant requirements regarding the certification of completion of mitigation activities for FFTs (by requiring senior management involvement) than it currently requires for other types of activities.

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	all submissions of MCRs is purely administrative and adds limited value to electric reliability and the overall protection of the BES. While Dominion supports the need for the submission of a MCR, Dominion does not support the unnecessary administrative burden of obtaining Senior Manager or Delegate approval for the submissions. Although the requirement for Senior Manager or Delegate approval of the MCR is consistent with the prior version, the section no longer appears to be consistent with the conceptual direction of Paragraph 81 of FERC's March 15, 2012 Order issued on NERC's Find, Fix and Track process, and CIP Version 5. BPA notes that a signed statement by the Senior Manager or Delegate is not required for the initial submission but is required for a "MCR". BPA suggests that Senior Manager or Delegate signature be required for the initial TFE submission, Amendments to Pending TFEs, and MCRs. PPL and MRONSRF - MCRs propose to include a senior manager statement. The initial TFE does not require a senior manager statement. Do not require senior manager approval. In paragraph 81 and CIP version 5, the direction is for senior manager approvals of policy and asset scope, not this level of constantly changing detail. **Other comments**		

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	TECO agrees with EEI comments regarding "Time Schedule" comments, Expiration Date comments, and comments regarding "Approved Pending TFE's". [the EEI comments are referenced above in section 4.2 and in the section related to implementation.]		
Section 6.9 – This section was modified to eliminate the requirement for a report to be submitted thirty days prior to the Expiration Date.	TECO agrees with EEI comments in Section 6.9. In addition, TECO is concerned that there should be some consistency throughout the Appendix 4D addressing "Time Scheduling" and "Expiration Date".	No additional change.	See comments above regarding Section 4.2.
Section 7.1 – This section was modified to revise the process for changes to a pending TFE request. A Responsible Entity may make any necessary changes without restarting the TFE request process during the first sixty days of review. At the end of the sixty-day period, the Regional Entity will approve or disapprove the TFE request with the information available to it unless the Regional Entity determines that it needs additional time. This modification is necessary to encourage complete submittals and discourage unnecessary amendments or revisions to the request that could delay the processing of the TFE request.	CE points out that the section refers to a 60-day review period when the TFE Request is under review by the Regional Entity and since this review period is not previously mentioned, it is not clear to what this refers. Entergy echoes CE's comment. SCE suggests including verbiage confirming if the amendment of a pending TFE request would extend the "safe harbor" and to provide examples of what would be considered to be, "…additional or revised Required Information." Similarly to the examples provided in Section 7.2.1. TECO is concerned that the Section may create more reports if an amendment is required to be filed with the MCR. PPL and MRONSRF - 7.1 refers to the "60-day review period" but this period was stricken when existing	See clarifications added to Section 5.2.	The 60-day review period reference has been introduced in the revised redline in section 5.2. As noted above, the amendment and the MCR are not duplicative and apply in different circumstances. The amendment, however, does not restart the review process.

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	5.1.3. (a) was deleted.		
Section 7.2.1 and 7.2.2 – These sections were modified to reflect the elimination of the Part A and B phases of the process.	BPA notes that amendments to TFEs only apply to pending TFEs. BPA suggests deleting Section 7.2, and renaming Section 7.0 "Amendment of a Pending TFE Request". Regarding Section 7.2.1, SCE suggests including examples of purposes for amending an Approved TFE if the decrease, or increase, of covered assets would require an amendment to the TFE.	Section 7.2 has been deleted since the MCR process is now explained in section 4.0 and 5.0.	N/A
Section 7.2.3 – This section was deleted to reflect the changes to the amendment process.	PPL - The amendment process needs further tightening: • to eliminate more non-value adding amendments, • to further streamline the steps and data required for an amendment, and • to reduce pancaked amendments (amendments to TFEs with previous amendments that are still in queue for approval).	No additional change.	As noted above, an amendment will only be submitted in connection with a pending TFE request.
Section 8.1 – This section was revised to allow, instead of require, that a Regional Entity conduct an audit following the approval of every TFE request. The Regional Entities should retain flexibility to determine audit schedules in connection with a number of factors, only one of which would be the verification of issues associated with TFE requests. Experience has demonstrated that a	TECO is concerned that the Section may create more reports if an amendment is required to be filled with the MCR. Additionally, TECO needs clarification on where Regional entity should retain flexibility to determine audit schedule. TECO also asks that audit timing be clarified.	No additional change.	The timing of the audit is at the discretion of the Regional Entity. Therefore, the Regional Entity does retain flexibility to determine the audit schedule.

Change proposed by NERC	Comment received	Outcome	Justification/Notes
number of TFE requests involve matters of low risk for which the rationales, evidence, documentation, and compensating and mitigating measures are uniform and familiar to Regional Entities and Responsible Entities alike. In some cases, verification in an audit may not be necessary.			
Section 9.1 – This section was revised to clarify the circumstances in which a TFE would be terminated.	No comment received.	N/A	N/A
Section 10.0 – This section has been deleted as the process is duplicative of the process for appealing Possible Violations.	SPP notes that although the hearing and appeals process may be duplicative to the one for Possible Violations, some mention of that avenue should be in this Appendix. To have removed it wholesale leaves the impression that there is no appeals process. Pointing to that process would be helpful. [LB: The following language was in the summary document "Section 10.0 – This section has been deleted as the process is duplicative of the process for appealing Possible Violations." It may be technically unnecessary, but I think taking out the appeals language altogether is not ideal.] GSOC states that rather than deleting Section 10, the ROP should state that process for appeals is the same as the process for appealing a possible violation. TAPS and APPA note that the Summary of Proposed Revision	The last sentence of section 10.0 has been reinstated for clarity, as suggested by commenters.	The appeal processes under the CMEP are not changing as a result of the proposed revisions to Appendix 4D. Therefore, no changes are necessary to ensure they are available to entities with TFEs that are not approved. However, for clarity, the last sentence of section 10.0 has been reinstated as suggested. The term "rejection" was subsequently removed from this section to reflect the consolidation of the review process and the elimination of the initial screening phase, in which the TFE request was "accepted" for further review and approval or "rejected."

Change proposed by NERC	Comment received	Outcome	Justification/Notes
	states that Section 10, which describes the hearing and appeal process for TFE requests, is being deleted because "the process is duplicative for the process for appealing Possible Violations." TAPS and APPA support the elimination of duplicative language from the Rules of Procedures, but not all of Section 10 is redundant. The last sentence of Section 10 explicitly states that a Registered Entity can raise issues relating to the disapproval of its TFE request in a hearing concerning a Notice of Alleged Violation relating to that TFE request. This sentence should be retained. Entergy does not approve of the deletion of the "Hearings and Appeals Process for Responsible Entity" section. While this process will still be more efficient, with less data to cause issues, disagreements will still occur, and Responsible Entities should still be provided a process through which to contest the Regional Entities disapproval of TFE requests, Amendments, and/or MCRs. BPA believes that this section provides some level of protection and redress if the Responsible Entity feels that the Regional Entity or NERC are being unreasonable. BPA suggests retaining this section.		
Section 11.2 – This section was revised to eliminate a process that has not proven particularly useful in the context of NERC's and the Regional Entity's	No comment received.	N/A	N/A

Change proposed by NERC	Comment received	Outcome	Justification/Notes
review of consistency in the approval and disapproval of TFE requests. Other steps, which remain in section 11.2, have been more effective in pursuing this objective.			
Section 11.3 – No change proposed by NERC	GSOC has asked that NERC and Regional Entities consider adding industry subject matter experts to the consistency committee described in section 11.3.	No additional change.	Although NERC is appreciative of the input provided by industry stakeholders, this is an internal ERO working group and, therefore, not the proper forum for stakeholder participation.
Section 12.0 – This section has been revised to reflect the elimination of the Part A and B phases of the TFE process.	Entergy finds that this section does not define MCRs as Confidential Information. TECO is concerned that this Section may create more reports if an amendment is required to be filled with the MCR. EEI observes that "MCRs" are not afforded the same confidentiality protections that "Amendments" receive. SCE observes that "MCRs" are not afforded the same confidentiality protections that "Amendments" receive.	This section has been clarified.	For purposes of confidential treatment, there are no differences between information submitted through an amendment or the MCR. This issue has been clarified in the redline. As noted above, an amendment is not required to be filed with the MCR.
N/A	N/A	N/A	Subsequent to the comment period, NERC removed the term "rejection" from section 13.1 to reflect the consolidation of the review process and the elimination of the initial screening phase, in which the TFE request was "accepted" for further review and approval or "rejected." This section was also revised to eliminate a cross reference to a deleted section.
Section 13.2 – This section has been deleted to eliminate the requirement of a quarterly report to NERC. It is noted, however,	Regarding Section 13, ERCOT requests that requirements for annual reports be removed. The Regional Entities will receive the TFE requests, any material changes to	No additional change required.	The proposed revisions eliminate all reports from Responsible Entities to the Regional Entities other than the MCR. Although information may be requested as needed, no regular reports are required. The annual report referenced in section 13 will be filed by NERC with FERC.

Change proposed by NERC	Comment received	Outcome	Justification/Notes
that both Regional Entities and Responsible Entities remain under the obligation to provide any information deemed necessary for NERC to fulfill its reporting obligations to FERC.	approved TFEs, and terminations of approved TFEs. The requirement for a Responsible Entity to file an annual report provides no value. PPL and MRONSRF Changes in Appendix 4D to Required Information and Registered Entity reporting must comprehend and encompass all the data required from the Registered Entities to support NERC's filing to FERC, including an accurate picture of the state of the industry on a wide area basis. Section 13 content for the annual report to FERC is essentially unchanged. Analysis of the annual report content versus Section 4.2 Required Information shows gaps. If Appendix 4D is approved as proposed, these gaps create exposure for after-the-fact data requests to Registered Entities to collect information for the annual report to FERC.		

PROCEDURE FOR REQUESTING AND RECEIVING

TECHNICAL FEASIBILITY EXCEPTIONS

TO NERC CRITICAL INFRASTRUCTURE PROTECTION STANDARDS

APPENDIX 4D TO THE RULES OF PROCEDURE

Effective: ~~January 31, 2012~~[DATE]

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PROCEDURE FOR REQUESTING AND RECEIVING TECHNICAL FEASIBILITY EXCEPTIONS TO NERC CRITICAL INFRASTRUCTURE PROTECTION STANDARDS

1.0 INTRODUCTION

1.1. Purpose

This Appendix to the Rules of Procedure of the North American Electric Reliability Corporation (NERC) provides the procedure by which a Responsible Entity may request and receive an exception from Strict Compliance with the terms of a Requirement of certain NERC Critical Infrastructure Protection (CIP) Standards on the grounds of technical feasibility or technical limitations. Such an exception is referred to herein as a Technical Feasibility Exception (TFE). This Appendix is intended to implement authorization granted by FERC to allow such exceptions to Applicable Requirements of CIP Standards.[1]

1.2. Authority

This Appendix is a NERC Rule of Procedure and an Electric Reliability Organization Rule. As such, this Appendix has been approved by (i) the NERC Board of Trustees and (ii) FERC. Any future revisions to this Appendix must be adopted in accordance with Article XI, section 2 of the NERC *Bylaws* and Section 1400 of the NERC *Rules of Procedure*, including approval by the NERC Board of Trustees and by FERC, in order to become effective.

1.3. Scope

This procedure for requesting and obtaining approval of TFEs is applicable only to those Requirements of CIP Standards CIP-002 through CIP-009 that (i) expressly provide either (A) that compliance with the terms of the Requirement is required where or as technically feasible, or (B) that technical limitations may preclude compliance with the terms of the Requirement, or (ii) FERC has directed should be subject to this procedure. As of the effective date of this Appendix, in the United States the Applicable Requirements are:

CIP-005-3: R2.4, R2.6, R3.1 and R3.2

CIP-006-3c: R1.1, including the Interpretation in Appendix 2

CIP-007-3: R2.3, R3, R4, R5.3, R 5.3.1, R 5.3.2, R 5.3.3, R6 and R6.3

Subsequent versions of these Requirements that are approved by FERC will continue to be Applicable Requirements, without the need to amend this Appendix to reflect the new version number of the CIP Standards, (i) if the subsequent versions continue to expressly provide either (A) that compliance with their terms is required where or as technically feasible or (B) that

[1] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) (*Order No. 706*), at PP 157-222.

technical limitations may preclude compliance with the terms of the Requirement[2]; or (ii) so long as FERC does not direct that the subsequent versions are no longer Applicable Requirements. Other Requirements of CIP Standards may become Applicable Requirements as the result of revisions to the CIP Standards in accordance with the NERC *Bylaws* and *Rules of Procedure* including Appendix 3A, *Standards Process Manual*, or as a result of FERC directive. NERC shall maintain a current list of Applicable Requirements on its website.

1.4 Obligations of Canadian Entities and Cross-Border Regional Entities

A Responsible Entity that is a Canadian Entity seeking a TFE shall work with the Regional Entity, NERC, and Applicable Governmental Authorities, to the extent permitted under Canadian federal or provincial laws, and without being obligated to authorize the disclosure of information prohibited by Canadian federal or provincial law from disclosure to FERC or other Applicable Governmental Authorities in the U.S., to comply with the requirements of this Appendix. A Canadian Entity shall not be required to subject itself to United States federal or state laws not otherwise applicable to the Canadian Entity in order to utilize this Appendix to obtain a TFE. Cross-Border Regional Entities shall implement this TFE Procedure in a manner consistent with their memoranda of understanding with Canadian Entities and Canadian Applicable Governmental Authorities concerning compliance monitoring and enforcement activities in particular provinces.

2.0. DEFINITIONS

For purposes of this Appendix, capitalized terms shall have the definitions set forth in Appendix 2 to the Rules of Procedure. For ease of reference, the definitions of the following terms that are used in this Appendix are also set forth below:

2.1 Annual Report: The report to be filed by NERC with FERC and other Applicable Governmental Authorities in accordance with Section 13.0 of this Appendix.

2.2 Applicable Requirement: A Requirement of a CIP Standard that (i) expressly provides either (A) that compliance with the terms of the Requirement is required where or as technically feasible, or (B) that technical limitations may preclude compliance with the terms of the Requirement; or (ii) is subject to this Appendix by FERC directive.

2.3 Canadian Entity: A Responsible Entity that is organized under Canadian federal or provincial law.

2.4 Critical Infrastructure Protection Standard or CIP Standard: Any of NERC Reliability Standards CIP-002 through CIP-009.

[2] *Order No. 706* at P 157 and note 65 and P 178.

2.5 Classified National Security Information: Required Information that has been determined to be protected from unauthorized disclosure pursuant to Executive Order No. 12958, as amended, and/or the regulations of the NRC at 10 C.F.R. §95.35; or pursuant to any comparable provision of Canadian federal or provincial law.

2.6 CMEP: The NERC *Uniform Compliance Monitoring and Enforcement Program* (Appendix 4C to the NERC *Rules of Procedure*) or the Commission-approved program of a Regional Entity, as applicable.

2.7 Compliant Date: The date by which a Responsible Entity is required to be in compliance with an Applicable Requirement of a CIP Standard.

2.8 Confidential Information: (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the course of an investigation; (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition; or (vii) any other information that is designated as Confidential Information in Section 11.0 of this Appendix.

2.9 Covered Asset: A Cyber Asset or Critical Cyber Asset that is subject to an Applicable Requirement.

2.10 Delegate: A person to whom the Senior Manager of a Responsible Entity has delegated authority pursuant to Requirement R2.3 of CIP Standard CIP-003-1 (or any successor provision).

2.11 Effective Date: The date, as specified in a notice ~~rejecting or~~ disapproving a TFE Request or terminating an approved TFE, on which the ~~rejection,~~ disapproval or termination becomes effective.

2.12 Eligible Reviewer: A person who has the required security clearances or other qualifications, or who otherwise meets the applicable criteria, to have access to Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information, as applicable to the particular information to be reviewed.

2.13 Expiration Date: The date on which an approved TFE expires.

2.14 FERC: The United States Federal Energy Regulatory Commission.

2.15 FOIA: The U.S. Freedom of Information Act, 5 U.S.C. §552.

2.16 Hearing Procedures: Attachment 2 to the NERC or Regional Entity CMEP, as applicable.

~~2.17~~2.17 **Material Change:** A change in facts that modifies Required Information in connection with an approved TFE. Examples of a Material Change could include, but are not limited to an increase in device count (but not a decrease), change in compensating measures, change in statement of basis for approval for the TFE, a change in the expiration date of the TFE, or a Responsible Entity achieving Strict Compliance with the Applicable Requirement.

2.18 Material Change Report: A report submitted by the Responsible Entity to the Regional Entity in the event there is a Material Change to the facts underlying an approved TFE pursuant to Section 4.0.

2.19 NRC: The United States Nuclear Regulatory Commission.

2.~~18~~20 NRC Safeguards Information: Required Information that is subject to restrictions on disclosure pursuant to 42 U.S.C. §2167 and the regulations of the NRC at 10 C.F.R. §73.21-73.23; or pursuant to comparable provisions of Canadian federal or provincial law.

~~**2.19 Part A Required Information**: Required Information that is to be provided in Part A of a Responsible Entity's TFE Request.~~

~~**2.20 Part B Required Information**: Required Information that is to be provided in Part B of a Responsible Entity's TFE Request.~~

2.21 Protected FOIA Information: Required Information, held by a governmental entity, that is subject to an exemption from disclosure under FOIA (5 U.S.C. §552(e)), under any similar state or local statutory provision, or under any comparable provision of Canadian federal or provincial law, which would be lost were the Required Information to be placed into the public domain.

2.22 Responsible Entity: An entity that is registered for a reliability function in the NERC Compliance Registry and is responsible for complying with an Applicable Requirement, as specified in the "Applicability" section of the CIP Standard.

2.23 Required Information: The information required to be provided in a TFE Request, as specified in Section 4.0 of this Appendix.

2.24 Senior Manager: The person assigned by the Responsible Entity, in accordance with CIP Standard CIP-003-1 Requirement R2 (or subsequent versions), to have overall responsibility for leading and managing the Responsible Entity's implementation of, and adherence to, the CIP Standards.

2.25 Strict Compliance: Compliance with the terms of an Applicable Requirement without reliance on a Technical Feasibility Exception.

2.26 Technical Feasibility Exception or TFE: An exception from Strict Compliance with the terms of an Applicable Requirement on grounds of technical feasibility or technical limitations in accordance with one or more of the criteria in Section 3.0 of this Appendix.

2.27 TFE Request: A request submitted by a Responsible Entity in accordance with this Appendix for an exception from Strict Compliance with an Applicable Requirement.

3.0. BASIS FOR APPROVAL OF A TECHNICAL FEASIBILITY EXCEPTION

3.1. A Responsible Entity may request and obtain approval for a TFE on the grounds that Strict Compliance with an Applicable Requirement, evaluated in the context or environment of the Responsible Entity's Covered Asset that is the subject of the TFE Request:

(i) is not technically possible or is precluded by technical limitations; or

(ii) is operationally infeasible or could adversely affect reliability of the Bulk Electric System to an extent that outweighs the reliability benefits of Strict Compliance with the Applicable Requirement; or

(iii) while technically possible and operationally feasible, cannot be achieved by the Responsible Entity's Compliant Date for the Applicable Requirement, due to factors such as, for example, scarce technical resources, limitations on the availability of required equipment or components, or the need to construct, install or modify equipment during planned outages; or

(iv) would pose safety risks or issues that, in the determination of the Regional Entity, outweigh the reliability benefits of Strict Compliance with the Applicable Requirement; or

(v) would conflict with, or cause the Responsible Entity to be non-compliant with, a separate statutory or regulatory requirement applicable to the Responsible Entity, the Covered Asset or the related Facility that must be complied with and cannot be waived or exempted; or

(vi) would require the incurrence of costs that, in the determination of the Regional Entity, far exceed the benefits to the reliability of the Bulk Electric System of Strict Compliance with the Applicable Requirement, such as for example by requiring the retirement of existing equipment that is not capable of Strict Compliance with the Applicable Requirement but is far from the end of its useful life and replacement with newer-generation equipment that is capable of Strict Compliance, where the incremental risk to the reliable operation of the Covered Asset and to the Reliable Operation of the related Facility and the Bulk Electric System of continuing to operate with the existing equipment is minimal in the determination of the Regional Entity.

3.2. A TFE does not relieve the Responsible Entity of its obligation to comply with the Applicable Requirement. Rather, a TFE authorizes an alternative (to Strict Compliance) means

of compliance with the Applicable Requirement through the use of compensating measures and/or mitigating measures that achieve at least a comparable level of security for the Bulk Electric System as would Strict Compliance with the Applicable Requirement.

3.3. The burden to justify approval of a TFE Request in accordance with the provisions of this Appendix is on the Responsible Entity. It is the responsibility of the Regional Entity, subject to oversight by NERC as provided in this Appendix, to make all determinations as to whether a TFE Request has met the criteria for approval.[3] NERC and the Regional Entities shall carry out the activities described in Section 11.0 of this Appendix to provide consistency in the review and approval or disapproval of TFE Requests across Regional Entities and across TFE Requests.

3.4. ~~A TFE typically must be requested for, and will be approved only for, a limited duration, until a stated Expiration Date. The Responsible Entity will be expected to achieve Strict Compliance with the Applicable Requirement by the Expiration Date. Under limited, justified circumstances, a~~A TFE Request may be approved without a specified Expiration Date, ~~subject to periodic review to verify~~however, in the event of a Material Change to the facts underlying an approved TFE, the Responsible Entity shall submit a Material Change Report providing continuing justification for the TFE or verifying Strict Compliance with the Applicable Requirement has been achieved.

4.0. FORM, CONTENTS AND SUBMISSION OF A TFE REQUEST OR MATERIAL CHANGE REPORT

~~4.1.~~ ~~Separate~~ Submissions for ~~Each~~a TFE Request or Material Change Report by Class

A ~~separate TFE Request shall be submitted for each Applicable Requirement pertaining to each Covered Asset for which the~~ Responsible Entity ~~seeks a TFE. There is one exception to this requirement: where the~~may seek a TFE for class-based categories of devices. A list of permissible class-based categories of devices will be maintained on NERC's website. In addition, a Responsible Entity ~~seeks TFEs~~may use one submission to request a TFE from the same Applicable Requirement for multiple, similar Covered Assets (either at the same location or at different locations within the geographic boundaries of a Regional Entity) on the same basis, with the same compensating measures and/or mitigating measures, and with the same proposed Expiration Date, the TFE Requests for all the Covered Assets may be included in one submission. ~~A TFE Request may not be submitted for Covered Assets located within the geographic boundaries of different Regional Entities.~~

[3] If a Regional Entity that is a Responsible Entity seeks a TFE in its role as a Responsible Entity, the Regional Entity shall submit its TFE Request to, as applicable, NERC or the Regional Entity that has assumed, by agreement approved by NERC and FERC, compliance monitoring and enforcement responsibilities with respect to the first Regional Entity's registered functions, as applicable. In such case NERC or the second Regional Entity, as applicable, will perform the duties and responsibilities of the "Regional Entity" specified in this Appendix.

4.2. Form and Format of TFE Request or Material Change Report

A TFE Request or a Material Change Report shall consist of ~~two parts:~~ the following Required Information:

~~(i) Part A of the TFE Request is the notification to a Regional Entity that a Responsible Entity is requesting a TFE. Part A must be submitted in a secure electronic form using the template provided by the Regional Entity. Regional Entities will use the Part A Required Information for initial screening to accept or reject the TFE Request.~~

~~(ii) Part B of the TFE Request contains the detailed material to support a TFE Request and includes the Documents, drawings, and other information necessary to provide the details and justification for the requested TFE. Part B must also include a detailed description of the compensating measures and/or mitigating measures the Responsible Entity will implement while the TFE is in effect. The Part B Required Information must be available at the Responsible Entity's location for review by the Regional Entity and/or NERC beginning on the date the TFE Request is submitted.~~

~~(iii) A Regional Entity may also require the Responsible Entity to file all or a portion of the Part B Required Information with the Regional Entity, provided that (A) the information can be filed in a secure manner that does not compromise the confidentiality of any Confidential Information, Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information, and (B) the Responsible Entity shall not be required to file with a Regional Entity any Part B Required Information if, and to the extent that, such filing is prohibited by law.~~

~~**4.3. Required Information to be Included in the TFE Request**~~

~~**4.3.1.** Part A of a TFE Request shall contain the Part A Required Information specified in this Section 4.3.1 and shall be submitted to the Regional Entity using its template referred to in Section 4.2. Consistent with the summary nature of the Part A Required Information, the Regional Entity's template may provide lists of responses to be selected by the Responsible Entity and/or limited space for narrative descriptions, for the Part A Required Information listed below. Failure to provide all Part A Required Information will result in rejection of the TFE Request as incomplete. The Part A Required Information shall consist of the following information:~~

~~1. Responsible Entity name.~~

~~2. Responsible Entity NERC ID.~~

~~3. TFE Request submittal date.~~

4. Whether the TFE Request is an original TFE Request or an amended TFE Request; and if it is an Amended TFE Request, the identification number of the original TFE Request.

5. Name, mailing address, phone number, facsimile number and E-mail address of the Responsible Entity's technical contact person for the TFE Request.

6. Applicable Requirement for which the TFE is being requested.

7. Number of Covered Assets for which the TFE is being requested.

8. Whether the Responsible Entity is filing a similar TFE Request(s) with one or more other Regional Entities, and if yes, the name(s) of the other Regional Entity(ies).

9. The type(s) of equipment, process, or procedure at or associated with the Covered Asset(s) and subject to or required by the Applicable Requirement, for which the TFE is being requested.

10. The basis for the TFE Request from the criteria specified in Section 3.1.

11. A brief statement describing and justifying why the Responsible Entity cannot achieve Strict Compliance with the Applicable Requirement.

12. The estimated impact on Reliable Operation of the Bulk Electric System of the Responsible Entity if the compensating measures and mitigating measures are not sufficient to achieve security for the Covered Assets, and cyber security is compromised.

13. A brief description of the compensating measures and/or mitigating measures that are planned or have been implemented in lieu of achieving Strict Compliance with the Applicable Requirement.

14. A statement as to whether or not the compensating measures and/or mitigating measures have been fully implemented at the time the TFE Request is submitted.

15. As applicable, (i) the actual implementation date(s) for the compensating measures and/or mitigating measures, and/or (ii) the proposed date(s) for implementing the proposed compensating measures and/or mitigating measures.

16. Whether the Responsible Entity has a proposed plan and time schedule for terminating the TFE and achieving Strict Compliance with the Applicable Requirement; if yes, the proposed Expiration Date and a description of the plan for terminating the TFE; if no, an explanation as to why a TFE with no Expiration Date is being requested.

~~17. Whether the TFE Request is supported, in whole or in part, by any of the following: Classified National Security Information; NRC Safeguards Information; or Protected FOIA Information.~~

~~18. A statement of the Responsible Entity's understanding of the requirement to submit timely periodic and other reports pertaining to the approved TFE.~~

(i) ~~19.~~ Category (pursuant to Section 4.1 or "other")
(ii) Device ID (assigned by the Responsible Entity)
(iii) Physical location of Device
(iv) Actual or estimated date in which device is placed into production
(v) Proposed TFE Expiration Date (if any)
(vi) Actual TFE Expiration Date (if any)
(vii) CIP Standard
(viii) CIP Requirement
(ix) Whether the TFE is also filed with other Regional Entities (if yes, which ones)
(x) Basis for Approval (pursuant to Section 3.0)
(xi) Compensating and Mitigating Measures
(xii) Date of completion of compensating and mitigating measures (if in progress, estimated completion date and time schedule)
(xiii) Whether the TFE is related to a self-certification or self-report
(xiv) Whether the has TFE been previously approved
(xv) TFE I.D., if known

A sample submittal will be maintained on NERC's website. Additional information may be requested by the Regional Entity as necessary or appropriate. At the discretion of the Regional Entity, information may be verified at a subsequent audit or spot-check or other form of monitoring.

A removal of a device from a TFE containing multiple devices of the same class does not require the filing of a Material Change Report. The information can be communicated during the next required submittal associated with the same class.

A statement, signed and dated by the Responsible Entity's Senior Manager or Delegate, that the Senior Manager or Delegate has read the TFE Request or Material Change Report and approved the proposed compensating measures and/or mitigating measures and the implementation plan, and that on behalf of the Responsible Entity that the Responsible Entity believes approval of the TFE Request or Material Change Report is warranted pursuant to the criteria specified in Section 3.1 of this Appendix.

At the time of the first (a) initial TFE request or (b) Material Change Report that is required to be submitted after approval of this Appendix 4D, a Responsible Entity will submit a complete

submittal in the form contemplated in this section to reflect previously approved and pending TFEs as well as any new information being submitted. This one-time submittal will be followed by the maintenance of the TFE information associated with such Responsible Entity, either through additional TFE requests or Material Change Reports pertaining to TFE requests already approved. The submittal of this baseline TFE submittal will not reopen any TFEs already approved under the old process or restart the review process of pending TFEs.

4.3. [Deleted]

4.4 Access to Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information Included in Required Information ~~**4.3.2** Part B of a TFE Request shall contain the Part B Required Information specified in this Section 4.3.2. Failure to include all Part B Required Information may result in disapproval of the TFE Request. The information provided for items 3 through 8 below should be comprehensive, as opposed to the summary information provided on the Part A submission, and should include any supporting Documents.~~

~~1. A copy of Part A of the TFE Request.~~

~~2. Location(s) of the Covered Asset(s) for which the TFE is (are) requested.~~

~~3. A statement of the basis, consistent with Section 3.1 of this Appendix, on which the Responsible Entity contends the TFE Request should be approved, with supporting documentation. Without limiting the content of this statement, it must include: (i) a description of the specific equipment, device(s), process(es) or procedure(s) at or associated with the Covered Asset(s) and subject to or required by the Applicable Requirement, for which the TFE is requested; and (ii) an explanation of why the Responsible Entity cannot achieve Strict Compliance with the Applicable Requirement.~~

~~4. A description of the compensating measures and/or mitigating measures the Responsible Entity proposes to implement and maintain as an alternate approach to achieving Strict Compliance with the Applicable Requirement, with supporting documentation. Without limiting the content of this description, it must include an explanation of how, and the extent to which, the proposed compensating measures and/or mitigating measures will reduce or prevent any adverse impacts on (i) the reliable operation of the Covered Asset(s) and (ii) the Reliable Operation of the Element(s) and Facility(ies) of the Bulk Electric System for which the Responsible Entity is responsible, resulting from the failure to achieve Strict Compliance with the Applicable Requirement, including reducing or eliminating any vulnerabilities resulting from lack of Strict Compliance.~~

~~5. An assessment of the impacts on (i) reliable operation of the Covered Asset(s) and (ii) Reliable Operation of the Elements and the Facility(ies), of the Bulk Electric System for which the Responsible Entity is responsible, if the proposed~~

compensating measures and/or mitigating measures are insufficient or unsuccessful.

6. The Responsible Entity's proposed time schedule for implementing the proposed compensating measures and/or mitigating measures. The TFE Request may identify compensating measures and or mitigating measures that have already been implemented by the Responsible Entity.

7. The Responsible Entity's proposed plan and time schedule for terminating the TFE and achieving Strict Compliance with the Applicable Requirement, including the Responsible Entity's proposed Expiration Date. The Responsible Entity should either (i) describe the specific steps it plans to take to achieve Strict Compliance and the planned schedule for each step, including the date by which the Responsible Entity intends to achieve Strict Compliance with the Applicable Requirement, and/or (ii) describe the specific research, design, analytical, testing or other activities the Responsible Entity intends to engage in to determine a means of achieving Strict Compliance with the Applicable Requirement, and the Responsible Entity's proposed time schedule for these activities.

8. If the Responsible Entity contends it will not be possible for it to achieve Strict Compliance with the Applicable Requirement and that the TFE being requested should have no Expiration Date, an explanation of why it will not be possible for the Responsible Entity to establish a date by which it can achieve Strict Compliance with the Applicable Requirement, why the TFE Request should be approved with no Expiration Date, and under what conditions, if any, the Responsible Entity will be able to achieve Strict Compliance with the Applicable Requirement at a future unknown and unspecified date.

9. The Responsible Entity's commitment to file quarterly reports with the Regional Entity on the Responsible Entity's progress (i) in implementing the proposed compensating measures and/or mitigating measures, and (ii) towards achieving Strict Compliance with the Applicable Requirement.

If the proposed Expiration Date is more than one (1) year from the date the TFE Request is submitted, or if the Responsible Entity contends the TFE should have no Expiration Date, the Responsible Entity's agreement to submit annual reports to the Regional Entity on the continued need for and justification for the TFE, for so long as the TFE remains in effect.

10. If the TFE Request is supported, in whole or in part, by Classified National Security Information, NRC Safeguards Information, and/or Protected FOIA Information, a statement identifying which of these categories each such item of information falls into and explaining why each such item of information is Classified National Security Information, NRC Safeguards Information, and/or Protected FOIA Information. If the Responsible Entity is prohibited by law from

~~disclosing any Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information to any person who is not an Eligible Reviewer (such as, for example, the restriction on access to Classified National Security Information specified in Section 4.1 of Executive Order No. 12958, as amended), the TFE Request shall identify the Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information that is subject to such restrictions on disclosure and shall identify the criteria which a person must meet in order to be an Eligible Reviewer of the Classified National Security Information, NRC Safeguards Information and/or Protected FOIA Information.~~

~~12. A statement, signed and dated by the Senior Manager or Delegate, that the Senior Manager or Delegate has read the TFE Request and approved the compensating measures and/or mitigating measures and the implementation plan, and on behalf of the Responsible Entity that the Responsible Entity believes approval of the TFE Request is warranted pursuant to the criteria in Section 3.1 of this Appendix.~~

~~**4.3.3.** All scheduled implementation dates and other activity dates, and the Expiration Date, in the TFE Request shall be stated as specific calendar dates.~~

~~**4.4 Access to Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information Included in Required Information**~~

4.4.1. Upon reasonable advance notice from a Regional Entity or NERC, and subject to Section 4.4.2, the Responsible Entity must provide the Regional Entity or NERC (i) with access to Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information included in the ~~Part B Required Information~~TFE Request, and (ii) with access to the Covered Asset(s) and the related Facility(ies) for purposes of making a physical review and inspection.

4.4.2. If the Responsible Entity is prohibited by law from disclosing any Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information to any person who is not an Eligible Reviewer (such as, for example, the restriction on access to Classified National Security Information specified in Section 4.1 of Executive Order No. 12958, as amended), then such Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information shall only be reviewed by a representative or representatives of the Regional Entity or NERC (which may include contractors) who are Eligible Reviewers.

4.4.3. The Regional Entity or NERC, as applicable, will work cooperatively with the Responsible Entity to access Protected FOIA Information in a way that does not waive or extinguish the exemption of the Protected FOIA Information from disclosure.

~~**4.5 Submission of TFE Request in Advance of Compliant Date**~~

~~The Responsible Entity should submit a TFE Request at least sixty (60) calendar days prior to the Responsible Entity's Compliant Date for the Applicable Requirement that is the subject of the TFE Request, to avoid the risk that the initial screening will not be completed by the Compliant Date and the Responsible Entity will become subject to issuance of a Notice of Alleged Violation for noncompliance with the Applicable Requirement. However, if a Responsible Entity whose Compliant Date for an Applicable Requirement was on or before December 31, 2009, submits a TFE Request for the Applicable Requirement by January 31, 2010 (either pursuant to this Appendix or pursuant to NERC Compliance Process Bulletin #2009-007 and Attachments 1 and 2 to that Bulletin), the Compliant Date will be deemed to be the date of submission of the TFE Request for purposes of Section 5.3 of this Appendix.~~

4.5 [Deleted]

5.0 REVIEW~~, ACCEPTANCE/REJECTION,~~ AND APPROVAL/DISAPPROVAL OF TFE REQUESTS OR MATERIAL CHANGE REPORTS

5.1. ~~Initial Screening~~Identification of TFE ~~Request for Acceptance~~Requests or ~~Rejection~~Material Change Reports

5.1.1. Upon receipt of ~~Part A of~~ a TFE Request or Material Change Report, the Regional Entity (i) will assign a unique identifier to the TFE Request~~, and (ii) will review the TFE Request to determine that the TFE Request is for an Applicable Requirement and that all Part A Required Information has been provided~~ or Material Change Report.

5.1.2. The unique identifier assigned to the TFE Request or Material Change Report will be in the form of XXXX-YYY-TFEZZZZZ, where "XXXX" is the year in which the TFE Request is received by the Regional Entity (*e.g.*, "2009"); "YYY" is the acronym for the Regional Entity within whose Region the Covered Asset is located[4]; and "ZZZZZ" is the sequential number of the TFE Requests received by the Regional Entity in that year. ~~If~~In the ~~TFE Request is amended or resubmitted~~case of a Material Change Report, "-AZ" will be added to the end of the identifier, where "Z" is the number of the ~~amendment~~Material Change Report to the TFE ~~Request~~.

~~**5.1.3.** (a) The Regional Entity will typically complete its initial screening within sixty (60) calendar days after receiving the TFE Request.~~

[4] The acronyms to be used are: FRCC (Florida Reliability Coordinating Council); MRO (Midwest Reliability Organization); NPCC (Northeast Power Coordinating Council); RFC (Reliability*First* Corporation); SERC (SERC Reliability Corporation); SPP (Southwest Power Pool Regional Entity); TRE (Texas Regional Entity/Texas Reliability Entity); and WECC (Western Electricity Coordinating Council).

(b) If the Regional Entity determines at any time that for a specified period of time, the Regional Entity will be unable to complete initial screenings of TFE Requests within sixty (60) calendar days after receipt and substantive reviews of TFE Requests within one year after receipt, the Regional Entity, based on consultation with NERC, shall establish an alternative time period objective and work plan for completing initial screenings and substantive reviews of TFE Requests during the specified period of time. The alternative time period objective and work plan shall be publicized by issuance of a notice to all Registered Entities within the geographic boundaries of the Regional Entity and by posting on the Regional Entity's website.

(c) If the Regional Entity is unable to complete its initial screening within sixty (60) calendar days after receiving the TFE Request, the Responsible Entity will not be subject to imposition of any findings of violations, or imposition of Penalties or sanctions for violations, for failure to be in Strict Compliance with the Applicable Requirement that is the subject of the TFE Request, beginning on the sixty-first (61st) calendar day after the Regional Entity received the TFE Request and continuing thereafter in accordance with Section 5.3.

5.1.4. If, based on its initial screening, the Regional Entity determines the TFE Request is for an Applicable Requirement and contains all Part A Required Information, and that the Part A Required Information provided by the Responsible Entity indicates the TFE Request satisfies the criteria for approval of a TFE in Section 3.1 of this Appendix, the Regional Entity shall send a notice to the Responsible Entity, with a copy to NERC, accepting the TFE Request as complete.

5.1.5. If the Regional Entity determines, based on its review of the Part A Required Information provided by the Responsible Entity, that the TFE Request (i) is not for an Applicable Requirement, or (ii) does not contain all Part A Required Information, or (iii) does not satisfy the criteria for approval of a TFE in Section 3.1 of this Appendix, the Regional Entity shall send a notice to the Responsible Entity, with a copy to NERC, rejecting the TFE Request. The notice shall state an Effective Date which shall be no less than thirty-one (31) calendar days and no more than sixty-one (61) calendar days after the date of issuance of the notice, unless the Regional Entity determines there are exceptional circumstances that justify a later Effective Date. If the Regional Entity determines the Effective Date should be more than sixty-one (61) calendar days after the date of issuance of the notice due to exceptional circumstances, the Regional Entity shall include a detailed statement of the exceptional circumstances in the notice.

5.1.6. If the Regional Entity rejects the TFE Request because not all Part A Required Information was provided, the Regional Entity's notice shall identify the Part A Required Information that was not provided in the TFE Request. The Responsible Entity may resubmit the TFE Request with all Part A Required Information included. If the Responsible Entity resubmits the TFE Request with all Part A Required Information included prior to the Effective Date, the Responsible Entity will not be subject to imposition of any findings of violations, or imposition of Penalties or sanctions for violations, for failure to be in Strict Compliance with the Applicable Requirement that is the subject of the TFE Request, during the period the Regional Entity is

~~conducting initial screening of the resubmitted TFE Request. The Responsible Entity may resubmit a TFE Request pursuant to this Section 5.1.6 only one time.~~

~~**5.1.7.** The Regional Entity must either acceptthe TFE Request in its entirety or reject the TFE Request in its entirety, even if the TFE Request is for two or more Covered Assets subject to the same Applicable Requirement.~~

5.2 ~~Substantive~~ Review of TFE Request or Material Change Report for Approval or Disapproval

5.2.1 The Regional Entity shall ~~conduct a substantive~~ review ~~of an accepted~~ a TFE Request or Material Change Report to determine if it should be approved in accordance with Section 3.1 of this Appendix, or disapproved. ~~The Regional Entity will conduct the substantive review in accordance with established compliance monitoring processes under the CMEP, such as a Compliance Audit or Spot Check.. The compliance monitoring activity may be conducted solely for the purpose of substantive review of the TFE Request, or may include review of the Responsible Entity's compliance with other Reliability Standards.~~ As part of its ~~substantive~~ review, the Regional Entity may request access to and review the ~~Part B~~ Required Information, including any Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information that is necessary to support the TFE Request; may conduct one or more physical inspections of the Covered Asset(s) and the related Facility(ies); may request additional information from the Responsible Entity; and may engage in discussions with the Responsible Entity concerning possible revisions to the TFE Request or Material Change Report.

5.2.2. The Regional Entity shall complete its ~~substantive~~ review of the TFE Request or Material Change Report and make its determination of whether the TFE Request or Material Change Report is approved or disapproved, and issue a notice (in accordance with Sections 5.2.4 or 5.2.5) stating the TFE Request is approved or disapproved, within ~~one (1) year~~60 days after receipt of the TFE Request ~~or within an alternative time period objective as specified in a work plan established under Section 5.1.3(b).~~. In addition, the Regional Entity may extend the ~~one-year~~60-day time period for individual TFE Requests or Material Change Reports by issuing a notice to the Responsible Entity, with a copy to NERC, stating the revised date by which the Regional Entity will issue its notice approving or disapproving the TFE Request or Material Change Report.

5.2.3. The Regional Entity ~~must either approvetthe TFE Request in its entirety~~may approve or disapprove the TFE Request or Material Change Report in whole or in ~~its entirety~~part, even if the TFE Request or Material Change Report is for two or more Covered Assets subject to the same Applicable Requirement or if it covers class-based categories of devices.

5.2.4. If the Regional Entity approves the TFE Request or Material Change Report, the Regional Entity shall issue a notice to the Responsible Entity, with a copy to NERC, stating that the TFE Request or Material Change Report is approved.

5.2.5. If the Regional Entity disapproves the TFE Request or Material Change Report, the Regional Entity shall issue a notice to the Responsible Entity, with a copy to NERC, stating that the TFE Request or Material Change Report is disapproved and stating the reasons for the disapproval. In its notice disapproving a TFE Request, the Regional Entity may also, but is not required to, state any revisions to the TFE Request the Regional Entity has identified, based on its review of the TFE Request, that, if made by the Responsible Entity, would result in approval of the TFE Request. Such revisions may include, but are not limited to, changes to the Responsible Entity's proposed (i) compensating measures and/or mitigating measures, (ii) implementation schedules, or (iii) Expiration Date. If the Responsible Entity submits an amended TFE Request to the Regional Entity incorporating, to the Regional Entity's satisfaction, the revisions to the TFE Request set forth in the notice of disapproval, then the Regional Entity shall issue a notice, in accordance with Section 5.2.4, approving the revised TFE Request.

5.2.6. A notice disapproving a TFE Request or Material Change Report shall state an Effective Date, which shall be no less than sixty-one (61) calendar days and no more than ninety-one (91) calendar days after the date of issuance of the notice, unless the Regional Entity determines there are exceptional circumstances that justify a later Effective Date. If the Regional Entity determines the Effective Date should be more than ninety-one (91) calendar days after the date of issuance of the notice due to exceptional circumstances, the Regional Entity shall include a detailed statement of the exceptional circumstances in the notice. Following the Effective Date, the Responsible Entity is subject to issuance of a Notice of Alleged Violation by the Regional Entity with respect to the Applicable Requirement that was the subject of the disapproved TFE Request or Material Change Report, unless the Responsible Entity (i) has submitted an amended TFE Request in accordance with Section 5.2.5, or (ii) has achieved Strict Compliance with the Applicable Requirement. Provided, that if the Effective Date occurs prior to the Responsible Entity's Compliant Date for the Applicable Requirement, then the Responsible Entity is not subject to issuance of a Notice of Alleged Violation until the Compliant Date. A Notice of Alleged Violation issued with respect to the Applicable Requirement shall be processed in accordance with Sections 5.0, 6.0 and 7.0 of the CMEP.

5.2.7 Within thirty (30) calendar days after issuing a notice approving or disapproving a TFE Request or Material Change Report, the Regional Entity shall submit a report to NERC setting forth the basis on which the Regional Entity approved or disapproved the TFE Request or Material Change Report. If the Regional Entity has disapproved the TFE Request or Material Change Report and determined there were exceptional circumstances justifying an Effective Date more than ninety-one (91) days after the date of issuance of the notice, the Regional Entity's report to NERC shall include a description of such exceptional circumstances.

5.2.8 A Responsible Entity may submit to NERC information that the Responsible Entity believes demonstrates that the approval, or disapproval or rejection by a Regional Entity of a TFE Request or Material Change Report submitted by the Responsible Entity constitutes an inconsistent application of the criteria specified in Section 3.1 as compared to other determinations of TFE Requests or Material Change Reports made by the same Regional Entity or another Regional Entity for the same type of Covered Assets, and with such submission may suggest that NERC request the Regional Entity to reconsider its approval, or disapproval or rejection of the TFE Request or Material Change Report. A Responsible Entity's submission to

NERC under this Section 5.2.8 shall be in writing and shall set forth (i) the TFE Request or Material Change Report for which the Responsible Entity received a determination that the Responsible Entity believes represents an inconsistent application of the criteria specified in Section 3.1 (using the identifier assigned to the TFE Request or Material Change Report pursuant to Section 5.1.2), (ii) a copy of the Regional Entity's notice of approval, or disapproval ~~or rejection~~ of the TFE Request or Material Change Report, and (iii) a description of the inconsistency in determinations that the Responsible Entity believes has occurred, including specific reference(s) to any other determinations of TFE Requests or Material Change Reports for the same type of Covered Assets that the Responsible Entity believes constitutes inconsistent application of the criteria specified in Section 3.1. The Responsible Entity's submission shall provide a clear and compelling demonstration that inconsistent applications of the criteria specified in Section 3.1 have occurred in the determinations of two or more TFE Requests or Material Change Reports for the same type of Covered Assets made by the same Regional Entity or two or more Regional Entities. NERC will provide a copy of the Responsible Entity's submission to the Regional Entity that approved, or disapproved ~~or rejected~~ the TFE Request or Material Change Report that is the subject of the submission. NERC will review the Responsible Entity's submission and the reports submitted by the Regional Entity or Regional Entities pursuant to Section 5.2.7 with respect to the TFE Requests or Material Change Reports that are the subject of the Responsible Entity's submission, and may decide, in accordance with Section 5.2.9, to request the Regional Entity to reconsider its determination. NERC will send a written notice to the Responsible Entity stating that NERC has determined to request reconsideration by the Regional Entity or has determined not to request reconsideration by the Regional Entity, as applicable.

5.2.9 NERC may request the Regional Entity to reconsider the approval, or disapproval ~~or rejection~~ of a TFE Request or Material Change Report, solely on the grounds that the approval, or disapproval ~~or rejection~~ would result in inconsistent application of the criteria specified in Section 3.1 as compared to determinations made on TFE Requests or Material Change Reports for the same type of Covered Assets by the same Regional Entity or a different Regional Entity. Requests for reconsideration on any other grounds are not allowed. A request for reconsideration shall be submitted in writing to the Regional Entity and shall set forth (i) the TFE Request or Material Change Report that is the subject of the request for reconsideration (using the identifier assigned to the TFE Request or Material Change Report pursuant to Section 5.1.2), (ii) a copy of the Regional Entity's notice of approval, or disapproval ~~or rejection~~ of the TFE Request or Material Change Report, and (iii) a description of the inconsistency in determinations on which NERC relies as the basis for the request for reconsideration, including specific reference(s) to other determinations of TFE Requests or Material Change Reports for the same type of Covered Asset that NERC believes constitutes inconsistent application of the criteria specified in Section 3.1. The Regional Entity shall consider the request for reconsideration and shall issue a notice to NERC and the affected Responsible Entity(ies) approving, disapproving or rejecting the TFE Request or Material Change Report in accordance with ~~Section 5.1.4, Section 5.1.5,~~ Section 5.2.4, Section 5.2.5, Section 5.2.6 and/or Section 9.2, as applicable, within one hundred twenty (120) days following receipt of the request for reconsideration. A determination on a request for reconsideration approving, or disapproving ~~or rejecting~~ a TFE Request or Material Change Report shall be effective prospectively only, from its Effective Date, provided, that if a Regional Entity receives a request for reconsideration of the

~~rejection or~~ disapproval of a TFE Request or Material Change Report prior to the Effective Date of the notice of ~~rejection or~~ disapproval, the Regional Entity shall issue a notice to the affected Responsible Entity pursuant to Section 5.~~1.5 or Section 5.~~2.6, as applicable, suspending the Effective Date pending determination of the request for reconsideration.

5.3 No Findings of Violations or Imposition of Penalties for Violations of an Applicable Requirement for the Period a TFE Request or Material Change Report is Being Reviewed

The Responsible Entity shall not be subject to imposition of any findings of violations, or imposition of Penalties or sanctions for violations, for failure to be in Strict Compliance with an Applicable Requirement that is the subject of a TFE Request or Material Change Report, for the period from:

(i) ~~the earlier of (A) the date of the Regional Entity's notice that the TFE Request is accepted as complete and (B)~~ the date that is sixty (60) calendar days after submission of the TFE Request or Material Change Report,

to:

(ii) (A) the date of the Regional Entity's notice that the TFE Request or Material Change Report is approved, or (B) the Effective Date of the Regional Entity's notice that the TFE Request ~~is rejected, or (B) the date of the Regional Entity's notice that the TFE Request is approved, or (C) the Effective Date of the Regional Entity's notice that the TFE Request~~or Material Change Report is disapproved, whichever is applicable.

Provided, that:

(1) while a TFE Request or Material Change Report is undergoing ~~initial screening~~review, the Regional Entity shall not issue a Notice of Alleged Violation to the Responsible Entity for being noncompliant with the Applicable Requirement that is the subject of the TFE Request or Material Change Report during the period on and after the TFE Request or Material Change Report was submitted;

(2) if the TFE Request or Material Change Report is ~~accepted~~approved, the Responsible Entity shall not be subject to imposition of any findings of violations, or imposition of Penalties or sanctions for violations, for failure to be in Strict Compliance with an Applicable Requirement that is the subject of the TFE Request or Material Change Report, during the period from submission of the TFE Request to the date of the Regional Entity's notice that the TFE Request ~~is accepted~~or Material Change Report is approved; and

(3) if the TFE Request ~~is~~disapproved~~or~~ Material Change Report is disapproved, and is found by the Regional Entity, NERC or FERC to have been fraudulent or

submitted not in good faith, the provisions of this Section 5.3 shall not apply, the Responsible Entity shall be subject to imposition of findings of violations and imposition of Penalties or sanctions for violations, for failure be in Strict Compliance with the Applicable Requirement that was the subject of the TFE Request or Material Change Report, for the entire period subsequent to the date the TFE Request or Material Change Report was submitted, and the Responsible Entity's fraudulent or not-in-good-faith submission of the TFE Request or Material Change Report shall be an aggravating factor in determining the amounts of Penalties or sanctions to be imposed on the Responsible Entity for such violations.

6.0 IMPLEMENTATION AND REPORTING BY THE RESPONSIBLE ENTITY PURSUANT TO AN APPROVED TFE OR MATERIAL CHANGE REPORT

6.1. The Responsible Entity will be required to implement compensating measures and/or mitigating measures as described, and in accordance with the time schedule(s) set forth, in the approved TFE.

6.2. ~~Unless~~In the event the TFE has been approved with ~~no~~an Expiration Date, the Responsible Entity will be required to implement steps, or conduct research and analysis, towards achieving Strict Compliance with the Applicable Requirements and eliminating the TFE, as described, and in accordance with the time schedule set forth, in the approved TFE.

~~**6.3.** The Responsible Entity shall submit quarterly reports to the Regional Entity on (i) the Responsible Entity's progress in implementing the compensating measures and/or mitigating measures the Responsible Entity is adopting pursuant to the approved TFE, and (ii) the Responsible Entity's progress in implementing steps and/or conducting research and/or analysis to achieve Strict Compliance with the Applicable Requirement.~~

~~**6.4.** All quarterly reports shall be submitted to the Regional Entity by no later than the last business day of the month immediately following the end of the calendar quarter for which the report is being submitted.~~

~~**6.5.** If the Expiration Date of the TFE is more than one (1) year after the TFE Request was submitted, or if the approved TFE has no Expiration Date, the Responsible Entity shall submit annual reports to the Regional Entity supporting the continuing need and justification for the approved TFE. The first annual report shall be due on the last business day of the month immediately following the end of the fourth calendar quarter after acceptance of the TFE Request. The annual report shall contain information as specified in items 1 through 10 and 13 of Section 4.3.2, but revised as appropriate based on current information as of the date of the report. The annual report shall not propose revisions to implementation, research and reporting dates that were specified in the approved TFE, but rather shall report on the Responsible Entity's progress and accomplishments in carrying out the implementation and research activities. Any revisions to implementation, research and reporting dates, or to other requirements, that were specified in the approved TFE shall be requested by an amendment filing in accordance with Section 7.2 of this Appendix~~

~~**6.6.** Each report submitted pursuant to Section 6.3 or Section 6.5 shall include a statement, signed and dated by the Senior Manager or Delegate, that the Senior Manager or Delegate has read, and approved the submission of, the report.~~

~~**6.7.** The Regional Entity shall issue an acknowledgement notice to the Responsible Entity and to NERC that a report has been received, but no other issuances shall be required from the Regional Entity in response to submission of such a report.~~

6.3. [Deleted]

6.4. [Deleted]

6.5. If there is a Material Change in the facts underlying approval of the TFE, the Responsible Entity shall submit a report to the Regional Entity supporting the continuing need and justification for the approved TFE or verifying that the Responsible Entity has achieved Strict Compliance with the Applicable Requirement pursuant to Section 4.0.

6.6 [Deleted]

6.7 [Deleted]

6.8. If a Responsible Entity fails to implement or maintain a compensating measure or mitigating measure or fails to conduct research or analysis towards achieving Strict Compliance, in accordance with the approved TFE; or fails to submit one or more reports by the required submission date, the Responsible Entity (i) is required to file a Self-Report in accordance with Section 3.5 of the CMEP, and (ii) will be subject to issuance of a Notice of Alleged Violation for noncompliance with the Applicable Requirement that is the subject of the approved TFE. Any such Notice of Alleged Violation shall be processed in accordance with Sections 5.0, 6.0 and 7.0 of the CMEP.

~~**6.9.** At least thirty (30) calendar days prior to the Expiration Date, the Responsible Entity shall submit a report to the Regional Entity, signed and dated by the Senior Manager or Delegate, demonstrating that the Responsible Entity has achieved, or will be able to achieve by the Expiration Date, Strict Compliance with the Applicable Requirement.~~

7.0 AMENDMENT OF A PENDING TFE REQUEST ~~OR APPROVED TFE~~

7.1. Amendment of a Pending TFE Request

A Responsible Entity may ~~at any time~~ amend a pending TFE Request that is under review by a Regional Entity, for the purpose of providing additional or revised Required Information. ~~The Responsible Entity shall submit an amended Part A and shall include in the Part B Required Information a written explanation of what Required Information is being added or revised and the purpose of the amendment.~~ during the 60-day review period. Submission of an amendment to a pending TFE Request may, in the Regional Entity's discretion, extend the time period for the

Regional Entity's ~~initial screening or substantive~~ review~~, as applicable,~~ of the TFE Request but does not require the restart of the approval process.

~~**7.2. Amendment of an Approved TFE**~~

~~**7.2.1.** A Responsible Entity may submit an amendment to an approved TFE for the purpose of requesting revision to any of the requirements specified in the approved TFE, such as, for example, revisions to the specific compensating measures and/or mitigating measures to be implemented, revisions to the schedule for implementing the compensating measures and/or mitigating measures, or a change in the Expiration Date. The Responsible Entity shall submit all the Part A Required Information, as amended, as specified in Section 4.3.1, and make available the Part B Required Information, as amended, as specified in Section 4.3.2. The Responsible Entity shall also include in the Part B Required Information a written explanation of the amendment, the reason for and purpose of the amendment, and the reason the requirements in the approved TFE should be revised.~~

~~**7.2.2.** The Regional Entity shall review the amended Part A Required Information to determine if it is complete, and shall issue a notice to the Responsible Entity, with a copy to NERC, stating if the amendment is accepted as complete or rejected as incomplete. If the Regional Entity issues a notice that the amendment is accepted as complete, the Regional Entity shall conduct a substantive review of the amendment, including such review of the amended Part B Required Information as the Regional Entity deems necessary, to determine if the amended TFE Request should be approved or disapproved, and shall issue a notice of approval or disapproval, in accordance with Section 5.2. If the Regional Entity determines the amendment should be approved, the TFE as amended replaces the previously approved TFE.~~

~~**7.2.3.** An approved TFE that is the subject of an amendment filing remains in effect unless and until the amendment is approved by the Regional Entity.~~

8.0 COMPLIANCE AUDIT REQUIREMENTS RELATING TO APPROVED TFE

8.1. Following approval of a Responsible Entity's TFE Request, subsequent Compliance Audits of the Responsible Entity ~~conducted prior to the Expiration Date shall~~may include audit of (i) the Responsible Entity's implementation and maintenance of the compensating measures and/or mitigating measures specified in the approved TFE, in accordance with the time schedule set forth in the approved TFE, and (ii) the Responsible Entity's implementation of steps and conduct of research and analyses towards achieving Strict Compliance with the Applicable Requirement, in accordance with the time schedule set forth in the approved TFE. These topics shall be included in such Compliance Audits regardless of whether a Compliance Audit was otherwise scheduled to include the CIP Standard that includes the Applicable Requirement.

8.2 The first Compliance Audit of the Responsible Entity subsequent to the Expiration Date shall include audit of the Responsible Entity's Strict Compliance with the Applicable Requirement that was the subject of the approved TFE. This topic shall be included

in such Compliance Audit regardless of whether it was otherwise scheduled to include the CIP Standard that includes the Applicable Requirement.

9.0 TERMINATION OF AN APPROVED TFE

9.1. An approved TFE shall ~~terminate~~remain in effect unless it terminates on its Expiration Date, ~~unless~~ it is terminated at an earlier date pursuant to this Section 9.0, the Responsible Entity achieves Strict Compliance with the Applicable Requirement or there is a material misrepresentation by the Responsible Entity as to the facts relied upon by the Regional Entity in approving the TFE.

9.2. The Responsible Entity may terminate an approved TFE by submitting a notice to the Regional Entity stating that the Responsible Entity is terminating the TFE and the Effective Date of the termination.

9.3. A Regional Entity or NERC may terminate an approved TFE based on the results of a Spot Check initiated and conducted pursuant to the CMEP to determine whether the approved TFE should be terminated prior to its Effective Date or should be revised to impose additional or different requirements or to advance the Expiration Date to an earlier date. Following issuance to the Responsible Entity of a draft Spot Check report concluding that the approved TFE should be terminated or revised (including by advancement of the Expiration Date), and opportunity for the Responsible Entity to submit comments on the draft Spot Check report, the Regional Entity or NERC, if it has determined that the approved TFE should be terminated or revised, shall issue a notice of termination to the Responsible Entity (with a copy to NERC if the notice is issued by the Regional Entity) stating the Effective Date of termination of the approved TFE. The Effective Date shall be no less than sixty-one (61) calendar days and no more than ninety-one (91) calendar days after the date of issuance of the notice of termination, unless the Regional Entity determines there are exceptional circumstances that justify a later Effective Date. If the Regional Entity determines the Effective Date should be more than ninety-one (91) calendar days after the issuance of the notice of termination due to exceptional circumstances, the Regional Entity shall include a detailed statement of the exceptional circumstances in the notice of termination.

9.4. The Responsible Entity shall not be subject to imposition of any findings of violations, or imposition of Penalties or sanctions for violations, for failure to be in Strict Compliance with an Applicable Requirement that is the subject of a TFE that has been terminated, until the Effective Date of the notice of termination.

10.0 HEARINGS AND APPEALS PROCESS FOR RESPONSIBLE ENTITY

~~A Responsible Entity whose TFE Request has been rejected or disapproved, or whose approved TFE has been terminated, and thereafter receives a Notice of Alleged Violation for the Applicable Requirement that was the subject of the TFE Request or the approved TFE, is entitled to a hearing before the Regional Entity Hearing Body (or before the NERC Compliance and Certification Committee if NERC is the Compliance Enforcement Authority with respect to the Responsible Entity's compliance with the Applicable Requirement), in accordance with the~~

~~Hearing Procedures, if the Responsible Entity contests the Notice of Alleged Violation, the proposed Penalty or sanction, or Mitigation Plan components. The Responsible Entity may raise issues relating to the rejection or~~The Responsible Entity may raise issues relating to the disapproval of its TFE Request or the termination of the approved TFE in the hearing concerning the Notice of Alleged Violation, proposed Penalty or sanction, or Mitigation Plan components.

11.0 CONSISTENCY IN APPROVAL AND DISAPPROVAL OF TFE REQUESTS AND MATERIAL CHANGE REPORTS

11.1. NERC and the Regional Entities will engage in the activities specified in this Section 11.0 for the purpose of assuring consistency in the review, approval and disapproval of TFE Requests and Material Change Reports (i) among the Regional Entities, (ii) among different types of Covered Assets that are subject to the same Applicable Requirement, (iii) with respect to the application of the criteria specified in Section 3.1 for approval of TFE Requests or Material Change Reports, including the comparison of safety risks and costs of Strict Compliance to reliability benefits of Strict Compliance, and (iv) with respect to the types of mitigating measures and compensating measures that are determined to be appropriate to support approval of TFE Requests~~.~~ or Material Change Reports. In appropriate cases, NERC will submit a request for reconsideration to a Regional Entity in accordance with Section 5.2.9.

11.2. The activities in which NERC and the Regional Entities will engage for the purposes stated in Section 11.1 will include, but not be limited to, the following activities:

~~1. NERC will review the reports of approved and disapproved TFE Requests submitted by the Regional Entities pursuant to Section 5.2.7 as the reports are received, and based on its review of such reports, NERC will issue to the Regional Entities, as Confidential Information, such guidance as NERC deems appropriate to achieve greater consistency in approval and disapproval of TFE Requests in the respects listed in Section 11.1.~~

1. [Deleted]
2. NERC will maintain, as Confidential Information, based on reports submitted by Regional Entities, a catalogue of the types of Covered Assets for which TFE Requests or Material Change Reports from the various Applicable Requirements have been approved and disapproved. The catalogue will be accessible to the Regional Entities for their use in connection with their substantive reviews of TFE Requests or Material Change Reports.

3. NERC and the Regional Entities will form a committee comprised of NERC and Regional Entity representatives involved in the review of TFE Requests or Material Change Reports and other Critical Infrastructure program activities, which shall be charged to review approved and disapproved TFE Requests or Material Change Reports for consistency and to issue such guidance to the Regional Entities, as Confidential Information, as the committee deems appropriate to achieve greater consistency in approval and disapproval of TFE Requests or Material Change Reports in the respects listed in Section 11.1. The

committee shall include persons with appropriate subject matter expertise for the responsibilities and activities of the committee.

4. NERC will submit to the FERC and to other Applicable Governmental Entities an annual informational report containing the following information concerning the manner in which Regional Entities have made determinations to approve or disapprove TFE Requests or Material Change Reports based on the criteria of Section 3.1:

(i) whether any issues were identified during the period covered by the informational report with respect to the consistency of the determinations made based on the criteria in Section 3.1, either within a Regional Entity or among Regional Entities;

(ii) a description of any such identified consistency issues;

(iii) how each consistency issue was resolved;

(iv) the numbers of TFE Requests or Material Change Reports for which reconsideration was requested pursuant to Section 5.2.9 based on purported inconsistencies in determinations applying the criteria in Section 3.1 and the numbers of such requests which resulted in TFE Requests or Material Change Reports being approved~~,~~ or disapproved ~~and rejected~~; and

(v) whether NERC has developed or is in a position to develop a uniform framework for Regional Entities to use to appraise the reliability benefits of Strict Compliance when making determinations based on the criteria in Section 3.1(iv) and (vi).

The first such informational report shall cover the period through June 30, 2011, and shall be filed with FERC and other Applicable Governmental Entities no later than September 28, 2011. Subsequent annual informational reports shall cover the period from July 1 through June 30 and shall be filed within 90 days following the end of the period covered by the report.

If NERC determines it is necessary to include any Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information in an informational report in order to satisfy the information requirements specified above, such Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information shall be contained in a separate non-public, confidential appendix to the informational report. Prior to submitting to FERC or another Applicable Governmental Authority a non-public, confidential appendix that provides specific Confidential Information, Classified National Security Information, NRC Safeguards Information, or Protected FOIA Information of a particular Responsible Entity and identifies the Responsible Entity or one of its

Facilities by name, NERC shall provide at least twenty-one (21) days advance notice to the Responsible Entity. The non-public, confidential appendix shall be submitted to FERC and other Applicable Governmental Authorities in accordance with their procedures for receiving confidential, proprietary and other protected information.

12.0 CONFIDENTIALITY OF TFE REQUESTS, MATERIAL CHANGE REPORTS AND RELATED INFORMATION

Except as expressly stated in this Section 12.0, the submission, review, ~~acceptance/rejection,~~ and approval/disapproval of TFE Requests or Material Change ReportS, and the implementation and termination of approved TFEs, shall be maintained as confidential. The following Documents are Confidential Information and shall be treated as such in accordance with Section 1500 of the NERC *Rules of Procedure*:

(i) All TFE Requests and ~~proposed~~ amendments~~, including without limiting the foregoing the Required Part A Information and Required Part B Information~~ or Material Change Reports submitted, filed or made available by the Responsible Entity;

(ii) All notices issued by a Regional Entity or NERC pursuant to this Appendix;

(iii) All requests for Documents or information made by a Regional Entity or NERC pursuant to this Appendix;

(iv) All submissions of Documents and information by a Responsible Entity to a Regional Entity or NERC pursuant to this Appendix;

(v) All post-approval reports submitted by a Responsible Entity pursuant to this Appendix;

(vi) All correspondence, notes, drawings, drafts, work papers, electronic communications, reports and other Documents generated by a Regional Entity or NERC in connection with a TFE Request or Material Change Report, including (without limiting the scope of this provision) in connection with reviewing a TFE Request or Material Change Report and supporting Documents and information submitted, filed or made available by the Responsible Entity, conducting a physical inspection of the Covered Asset(s) or the related Facility(ies), reviewing and analyzing post-approval reports submitted by a Responsible Entity, or conducting compliance monitoring processes pursuant to the CMEP with respect to a TFE Request or Material Change Report or approved TFE.

(vii) All guidance issued to Regional Entities pursuant to Section 11.2 by NERC or by the committee described in Section 11.2(3), and all minutes of meetings of the committee and discussions between or among its members.

(viii) All submissions by Responsible Entities to NERC pursuant to Section 5.2.8.

(ix) All requests for reconsideration pursuant to Section 5.2.9.

(x) Any confidential appendix to an informational report prepared and submitted pursuant to Section 11.2(4) or to an Annual Report prepared and submitted pursuant to Section 13.0.

13.0 ANNUAL REPORT TO FERC AND OTHER APPLICABLE GOVERNMENTAL AUTHORITIES

13.1. Contents of Annual Report

NERC shall submit an Annual Report to FERC that provides a Wide-Area analysis or analyses, which NERC shall prepare in consultation with the Regional Entities, regarding the use of TFEs and the impact on the reliability of the Bulk Electric System, as required by Paragraphs 220 and 221 of *Order No. 706*, which state:

> . . . [W]e direct the ERO to submit an annual report to the Commission that provides a wide-area analysis regarding use of the technical feasibility exception and the effect on Bulk-Power System reliability. The annual report must address, at a minimum, the frequency of the use of such provisions, the circumstances or justifications that prompt their use, the interim mitigation measures used to address vulnerabilities, and efforts to eliminate future reliance on the exception. . . [T]he report should contain aggregated data with sufficient detail for the Commission to understand the frequency with which specific provisions are being invoked as well as high level data regarding mitigation and remediation plans over time and by region . . . .

Copies of the Annual Report shall be filed with other Applicable Governmental Authorities. The Annual Report shall contain, at a minimum, the following information:

(i) The frequency of use of the TFE Request process, disaggregated by Regional Entity and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, including (A) the numbers of TFE Requests that have been submitted~~, accepted/rejected,~~ and approved/disapproved during the preceding year and cumulatively since the effective date of this Appendix, (B) the numbers of unique Covered Assets for which TFEs have been approved, (C) the numbers of approved TFEs that are still in effect as of on or about the date of the Annual Report; (D) the numbers of approved TFEs that reached their Expiration Dates or were terminated during the preceding year; and (E) the numbers of approved TFEs that are scheduled to reach their Expiration Dates during the ensuing year;

(ii) Categorization of the submitted and approved TFE Requests to date by broad categories such as the general nature of the TFE Request, the Applicable Requirements

covered by submitted and approved TFE Requests, and the types of Covered Assets that are the subject of submitted and approved TFE Requests;

(iii) Categorization of the circumstances or justifications on which the approved TFEs to date were submitted and approved, by broad categories such as the need to avoid replacing existing equipment with significant remaining useful lives, unavailability of suitable equipment to achieve Strict Compliance in a timely manner, or conflicts with other statutes and regulations applicable to the Responsible Entity;

(iv) Categorization of the compensating measures and mitigating measures implemented and maintained by Responsible Entities pursuant to approved TFEs, by broad categories of compensating measures and mitigating measures and by types of Covered Assets;

(v) For each TFE Request that was ~~rejected or~~ disapproved, and for each TFE that was terminated, but for which, due to exceptional circumstances as determined by the Regional Entity, the Effective Date was later than the latest date specified in Section 5.~~1.5, 5.~~2.6, or 9.3, as applicable, a statement of the number of days the Responsible Entity was not subject to imposition of findings of violations of the Applicable Requirement or imposition of Penalties or sanctions pursuant to Section 5.3.

(vi) A discussion, on an aggregated basis, of Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures, and the implementation of steps and the conduct of research and analyses to achieve Strict Compliance with the Applicable Requirements, by Responsible Entities in accordance with approved TFEs;

(vii) Assessments, by Regional Entity (and for more discrete areas within a Regional Entity, if appropriate) and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, of the Wide-Area impacts on the reliability of the Bulk Electric System of approved TFEs in the aggregate, including the compensating measures and mitigating measures that have been implemented; and

(viii) Discussion of efforts to eliminate future reliance on TFEs.

~~**13.2. Submission of Quarterly Reports by Regional Entities to NERC**~~

~~In order to facilitate timely preparation of the Annual Report, each Regional Entity shall submit to NERC, within thirty (30) calendar days following the end of each calendar quarter, a report listing (i) the types of Covered Assets with respect to which TFE Requests were approved during such quarter, and (ii) final totals for the quarter of TFE Requests accepted and rejected and TFE Requests approved and disapproved. The reports submitted by the Regional Entities to NERC shall be Confidential Information.~~

13.3. Due Date for Annual Reports

The first Annual Report shall cover the period through June 30, 2011, and shall be filed with FERC and with other Applicable Governmental Authorities no later than 90 days after the end of such calendar quarter. Subsequent Annual Reports shall be filed at one year intervals thereafter.

13.4. Annual Report to be a Public Document; Confidential Appendix

It is the intent of this Appendix that the Annual Report be a public document. Therefore, NERC shall prepare the annual report in such a manner that it does not include or disclose any Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information. However, if NERC determines it is necessary to include any Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information in an Annual Report in order to satisfy the information requirements specified in this Appendix or required by FERC or other Applicable Governmental Authorities, such Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information shall be contained in a separate non-public, confidential appendix to the Annual Report. Prior to submitting to FERC or another Applicable Governmental Authority a non-public, confidential appendix that provides specific Confidential Information, Classified National Security Information, NRC Safeguards Information, or Protected FOIA Information of a particular Responsible Entity and identifies the Responsible Entity or one of its Facilities by name, NERC shall provide at least twenty-one (21) days advance notice to the Responsible Entity. The non-public, confidential appendix shall be submitted to FERC and other Applicable Governmental Authorities in accordance with their procedures for receiving confidential, proprietary and other protected information.

13.5. Responsible Entities Must Cooperate in Preparation of Annual Report

As specified in Paragraph 220, note 74 of Order No. 706, Responsible Entities must cooperate with NERC and Regional Entities in providing information deemed necessary for NERC to fulfill its reporting obligations to FERC.

PROCEDURE FOR REQUESTING AND RECEIVING

TECHNICAL FEASIBILITY EXCEPTIONS

TO NERC CRITICAL INFRASTRUCTURE PROTECTION STANDARDS

APPENDIX 4D TO THE RULES OF PROCEDURE

Effective: [DATE]

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[TO COME]

PROCEDURE FOR REQUESTING AND RECEIVING TECHNICAL FEASIBILITY EXCEPTIONS TO NERC CRITICAL INFRASTRUCTURE PROTECTION STANDARDS

1.0 INTRODUCTION

1.1. Purpose

This Appendix to the Rules of Procedure of the North American Electric Reliability Corporation (NERC) provides the procedure by which a Responsible Entity may request and receive an exception from Strict Compliance with the terms of a Requirement of certain NERC Critical Infrastructure Protection (CIP) Standards on the grounds of technical feasibility or technical limitations. Such an exception is referred to herein as a Technical Feasibility Exception (TFE). This Appendix is intended to implement authorization granted by FERC to allow such exceptions to Applicable Requirements of CIP Standards.[1]

1.2. Authority

This Appendix is a NERC Rule of Procedure and an Electric Reliability Organization Rule. As such, this Appendix has been approved by (i) the NERC Board of Trustees and (ii) FERC. Any future revisions to this Appendix must be adopted in accordance with Article XI, section 2 of the NERC *Bylaws* and Section 1400 of the NERC *Rules of Procedure*, including approval by the NERC Board of Trustees and by FERC, in order to become effective.

1.3. Scope

This procedure for requesting and obtaining approval of TFEs is applicable only to those Requirements of CIP Standards CIP-002 through CIP-009 that (i) expressly provide either (A) that compliance with the terms of the Requirement is required where or as technically feasible, or (B) that technical limitations may preclude compliance with the terms of the Requirement, or (ii) FERC has directed should be subject to this procedure. As of the effective date of this Appendix, in the United States the Applicable Requirements are:

CIP-005-3: R2.4, R2.6, R3.1 and R3.2

CIP-006-3c: R1.1, including the Interpretation in Appendix 2

CIP-007-3: R2.3, R3, R4, R5.3, R 5.3.1, R 5.3.2, R 5.3.3, R6 and R6.3

Subsequent versions of these Requirements that are approved by FERC will continue to be Applicable Requirements, without the need to amend this Appendix to reflect the new version number of the CIP Standards, (i) if the subsequent versions continue to expressly provide either (A) that compliance with their terms is required where or as technically feasible or (B) that

[1] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) (*Order No. 706*), at PP 157-222.

technical limitations may preclude compliance with the terms of the Requirement[2]; or (ii) so long as FERC does not direct that the subsequent versions are no longer Applicable Requirements. Other Requirements of CIP Standards may become Applicable Requirements as the result of revisions to the CIP Standards in accordance with the NERC *Bylaws* and *Rules of Procedure* including Appendix 3A, *Standards Process Manual*, or as a result of FERC directive. NERC shall maintain a current list of Applicable Requirements on its website.

1.4 Obligations of Canadian Entities and Cross-Border Regional Entities

A Responsible Entity that is a Canadian Entity seeking a TFE shall work with the Regional Entity, NERC, and Applicable Governmental Authorities, to the extent permitted under Canadian federal or provincial laws, and without being obligated to authorize the disclosure of information prohibited by Canadian federal or provincial law from disclosure to FERC or other Applicable Governmental Authorities in the U.S., to comply with the requirements of this Appendix. A Canadian Entity shall not be required to subject itself to United States federal or state laws not otherwise applicable to the Canadian Entity in order to utilize this Appendix to obtain a TFE. Cross-Border Regional Entities shall implement this TFE Procedure in a manner consistent with their memoranda of understanding with Canadian Entities and Canadian Applicable Governmental Authorities concerning compliance monitoring and enforcement activities in particular provinces.

2.0. DEFINITIONS

For purposes of this Appendix, capitalized terms shall have the definitions set forth in Appendix 2 to the Rules of Procedure. For ease of reference, the definitions of the following terms that are used in this Appendix are also set forth below:

2.1 Annual Report: The report to be filed by NERC with FERC and other Applicable Governmental Authorities in accordance with Section 13.0 of this Appendix.

2.2 Applicable Requirement: A Requirement of a CIP Standard that (i) expressly provides either (A) that compliance with the terms of the Requirement is required where or as technically feasible, or (B) that technical limitations may preclude compliance with the terms of the Requirement; or (ii) is subject to this Appendix by FERC directive.

2.3 Canadian Entity: A Responsible Entity that is organized under Canadian federal or provincial law.

2.4 Critical Infrastructure Protection Standard or CIP Standard: Any of NERC Reliability Standards CIP-002 through CIP-009.

[2] *Order No. 706* at P 157 and note 65 and P 178.

2.5 Classified National Security Information: Required Information that has been determined to be protected from unauthorized disclosure pursuant to Executive Order No. 12958, as amended, and/or the regulations of the NRC at 10 C.F.R. §95.35; or pursuant to any comparable provision of Canadian federal or provincial law.

2.6 CMEP: The NERC *Uniform Compliance Monitoring and Enforcement Program* (Appendix 4C to the NERC *Rules of Procedure*) or the Commission-approved program of a Regional Entity, as applicable.

2.7 Compliant Date: The date by which a Responsible Entity is required to be in compliance with an Applicable Requirement of a CIP Standard.

2.8 Confidential Information: (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the course of an investigation; (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition; or (vii) any other information that is designated as Confidential Information in Section 11.0 of this Appendix.

2.9 Covered Asset: A Cyber Asset or Critical Cyber Asset that is subject to an Applicable Requirement.

2.10 Delegate: A person to whom the Senior Manager of a Responsible Entity has delegated authority pursuant to Requirement R2.3 of CIP Standard CIP-003-1 (or any successor provision).

2.11 Effective Date: The date, as specified in a notice disapproving a TFE Request or terminating an approved TFE, on which the disapproval or termination becomes effective.

2.12 Eligible Reviewer: A person who has the required security clearances or other qualifications, or who otherwise meets the applicable criteria, to have access to Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information, as applicable to the particular information to be reviewed.

2.13 Expiration Date: The date on which an approved TFE expires.

2.14 FERC: The United States Federal Energy Regulatory Commission.

2.15 FOIA: The U.S. Freedom of Information Act, 5 U.S.C. §552.

2.16 Hearing Procedures: Attachment 2 to the NERC or Regional Entity CMEP, as applicable.

2.17 Material Change: ~~An update to~~A change in facts that modifies Required Information in connection with an approved TFE ~~that modifies key data in the TFE request.~~. Examples of a

Material Change could include, but are not limited to an increase in device count~~,~~ (but not a decrease), change in compensating measures, change in statement of basis for approval for the TFE, a change in the expiration date of the TFE, or a Responsible Entity achieving Strict Compliance with the Applicable Requirement.

2.18 Material Change Report: A report submitted by the Responsible Entity to the Regional Entity in the event there is a Material Change to the facts underlying an approved TFE~~.~~ pursuant to Section 4.0.

2.19 NRC: The United States Nuclear Regulatory Commission.**2.20 NRC Safeguards Information:** Required Information that is subject to restrictions on disclosure pursuant to 42 U.S.C. §2167 and the regulations of the NRC at 10 C.F.R. §73.21-73.23; or pursuant to comparable provisions of Canadian federal or provincial law.

2.21 Protected FOIA Information: Required Information, held by a governmental entity, that is subject to an exemption from disclosure under FOIA (5 U.S.C. §552(e)), under any similar state or local statutory provision, or under any comparable provision of Canadian federal or provincial law, which would be lost were the Required Information to be placed into the public domain.

2.22 Responsible Entity: An entity that is registered for a reliability function in the NERC Compliance Registry and is responsible for complying with an Applicable Requirement, as specified in the "Applicability" section of the CIP Standard.

2.23 Required Information: The information required to be provided in a TFE Request, as specified in Section 4.0 of this Appendix.

2.24 Senior Manager: The person assigned by the Responsible Entity, in accordance with CIP Standard CIP-003-1 Requirement R2 (or subsequent versions), to have overall responsibility for leading and managing the Responsible Entity's implementation of, and adherence to, the CIP Standards.

2.25 Strict Compliance: Compliance with the terms of an Applicable Requirement without reliance on a Technical Feasibility Exception.

2.26 Technical Feasibility Exception or TFE: An exception from Strict Compliance with the terms of an Applicable Requirement on grounds of technical feasibility or technical limitations in accordance with one or more of the criteria in Section 3.0 of this Appendix.

2.27 TFE Request: A request submitted by a Responsible Entity in accordance with this Appendix for an exception from Strict Compliance with an Applicable Requirement.

3.0. BASIS FOR APPROVAL OF A TECHNICAL FEASIBILITY EXCEPTION

3.1. A Responsible Entity may request and obtain approval for a TFE on the grounds that Strict Compliance with an Applicable Requirement, evaluated in the context or environment of the Responsible Entity's Covered Asset that is the subject of the TFE Request:

(i) is not technically possible or is precluded by technical limitations; or

(ii) is operationally infeasible or could adversely affect reliability of the Bulk Electric System to an extent that outweighs the reliability benefits of Strict Compliance with the Applicable Requirement; or

(iii) while technically possible and operationally feasible, cannot be achieved by the Responsible Entity's Compliant Date for the Applicable Requirement, due to factors such as, for example, scarce technical resources, limitations on the availability of required equipment or components, or the need to construct, install or modify equipment during planned outages; or

(iv) would pose safety risks or issues that, in the determination of the Regional Entity, outweigh the reliability benefits of Strict Compliance with the Applicable Requirement; or

(v) would conflict with, or cause the Responsible Entity to be non-compliant with, a separate statutory or regulatory requirement applicable to the Responsible Entity, the Covered Asset or the related Facility that must be complied with and cannot be waived or exempted; or

(vi) would require the incurrence of costs that, in the determination of the Regional Entity, far exceed the benefits to the reliability of the Bulk Electric System of Strict Compliance with the Applicable Requirement, such as for example by requiring the retirement of existing equipment that is not capable of Strict Compliance with the Applicable Requirement but is far from the end of its useful life and replacement with newer-generation equipment that is capable of Strict Compliance, where the incremental risk to the reliable operation of the Covered Asset and to the Reliable Operation of the related Facility and the Bulk Electric System of continuing to operate with the existing equipment is minimal in the determination of the Regional Entity.

3.2. A TFE does not relieve the Responsible Entity of its obligation to comply with the Applicable Requirement. Rather, a TFE authorizes an alternative (to Strict Compliance) means of compliance with the Applicable Requirement through the use of compensating measures and/or mitigating measures that achieve at least a comparable level of security for the Bulk Electric System as would Strict Compliance with the Applicable Requirement.

3.3. The burden to justify approval of a TFE Request in accordance with the provisions of this Appendix is on the Responsible Entity. It is the responsibility of the Regional Entity, subject to oversight by NERC as provided in this Appendix, to make all determinations as to

whether a TFE Request has met the criteria for approval.[3] NERC and the Regional Entities shall carry out the activities described in Section 11.0 of this Appendix to provide consistency in the review and approval or disapproval of TFE Requests across Regional Entities and across TFE Requests.

3.4. A TFE Request may be approved without a specified Expiration Date, however, in the event of a Material Change to the facts underlying an approved TFE, the Responsible Entity shall submit a Material Change Report providing continuing justification for the TFE or verifying Strict Compliance with the Applicable Requirement has been achieved.

4.0. FORM, CONTENTS AND SUBMISSION OF A TFE REQUEST OR MATERIAL CHANGE REPORT

~~4.1.~~ Submissions for a TFE Request or Material Change Report by Class

A Responsible Entity may seek a TFE for class-based categories of devices. A list of permissible class-based categories of devices will be maintained on NERC's ~~web site~~website. In addition, a Responsible Entity may use one submission to request a TFE from the same Applicable Requirement for multiple, similar Covered Assets (either at the same location or at different locations within the geographic boundaries of a Regional Entity) on the same basis, with the same compensating measures and/or mitigating measures, and with the same proposed Expiration Date, the TFE Requests for all the Covered Assets may be included in one submission.

4.2. Form and Format of TFE Request or Material Change Report

A TFE Request or a Material Change Report shall consist of the following Required Information:

(i) Category (pursuant to Section 4.1 or "other")
~~(i)~~(ii) Device ID (assigned by the Responsible Entity)
(iii) Physical location of Device
(iv) Actual or estimated date in which device is placed into production
(v) Proposed TFE Expiration Date (if any)
(vi) Actual TFE Expiration Date (if any)
(vii) CIP Standard~~/~~
~~(ii)~~(viii) CIP Requirement

[3] If a Regional Entity that is a Responsible Entity seeks a TFE in its role as a Responsible Entity, the Regional Entity shall submit its TFE Request to, as applicable, NERC or the Regional Entity that has assumed, by agreement approved by NERC and FERC, compliance monitoring and enforcement responsibilities with respect to the first Regional Entity's registered functions, as applicable. In such case NERC or the second Regional Entity, as applicable, will perform the duties and responsibilities of the "Regional Entity" specified in this Appendix.

~~(iii)Date of installation~~
(ix) Whether the TFE is also filed with other Regional Entities (if yes, which ones)
(x) Basis for Approval (pursuant to Section 3.0)
~~(iv)~~(xi) Compensating and Mitigating Measures
~~(v) Rational for the TFE (Statement of Basis)~~
(xii) Date of completion of compensating and mitigating measures (if in progress, estimated completion date and time schedule)
~~(vi)~~(xiii) Whether the TFE is related to a self-certification or self-report
~~(vii)~~(xiv) Whether the ~~has TFE~~has TFE been previously approved
~~(viii)~~(xv) TFE I.D., if known

A sample submittal will be maintained on NERC's website. Additional information may be requested by the Regional Entity as necessary or appropriate. At the discretion of the Regional Entity, information may be verified at a subsequent audit or spot-check or other form of monitoring.

A removal of a device from a TFE containing multiple devices of the same class does not require the filing of a Material Change Report. The information can be communicated during the next required submittal associated with the same class.

A statement, signed and dated by the Responsible Entity's Senior Manager or Delegate, that the Senior Manager or Delegate has read the TFE Request or Material Change Report and approved the proposed compensating measures and/or mitigating measures and the implementation plan, and that on behalf of the Responsible Entity that the Responsible Entity believes approval of the TFE Request or Material Change Report is warranted pursuant to the criteria specified in Section 3.1 of this Appendix.

At the time of the first (a) initial TFE request or (b) Material Change Report that is required to be submitted after approval of this Appendix 4D, a Responsible Entity will submit a complete submittal in the form contemplated in this section to reflect previously approved and pending TFEs as well as any new information being submitted. This one-time submittal will be followed by the maintenance of the TFE information associated with such Responsible Entity, either through additional TFE requests or Material Change Reports pertaining to TFE requests already approved. The submittal of this baseline TFE submittal will not reopen any TFEs already approved under the old process or restart the review process of pending TFEs.

4.3. [Deleted]

4.4 Access to Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information Included in Required Information

4.4.1. Upon reasonable advance notice from a Regional Entity or NERC, and subject to Section 4.4.2, the Responsible Entity must provide the Regional Entity or NERC (i) with access to Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information included in the TFE Request, and (ii) with access to the Covered Asset(s) and the related Facility(ies) for purposes of making a physical review and inspection.

4.4.2. If the Responsible Entity is prohibited by law from disclosing any Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information to any person who is not an Eligible Reviewer (such as, for example, the restriction on access to Classified National Security Information specified in Section 4.1 of Executive Order No. 12958, as amended), then such Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information shall only be reviewed by a representative or representatives of the Regional Entity or NERC (which may include contractors) who are Eligible Reviewers.

4.4.3. The Regional Entity or NERC, as applicable, will work cooperatively with the Responsible Entity to access Protected FOIA Information in a way that does not waive or extinguish the exemption of the Protected FOIA Information from disclosure.

~~**4.5 Submission of TFE Request in Advance of Compliant Date**~~

~~The Responsible Entity should submit a TFE Request at least sixty (60) calendar days prior to the Responsible Entity's Compliant Date for the Applicable Requirement that is the subject of the TFE Request, to avoid the risk that the review will not be completed by the Compliant Date and the Responsible Entity will become subject to issuance of a Notice of Alleged Violation for noncompliance with the Applicable Requirement. However, if a Responsible Entity whose Compliant Date for an Applicable Requirement was on or before December 31, 2009, submits a TFE Request for the Applicable Requirement by January 31, 2010 (either pursuant to this Appendix or pursuant to NERC Compliance Process Bulletin #2009-007 and Attachments 1 and 2 to that Bulletin), the Compliant Date will be deemed to be the date of submission of the TFE Request for purposes of Section 5.3 of this Appendix.~~

4.5 [Deleted]

5.0 REVIEW AND APPROVAL/DISAPPROVAL OF TFE REQUESTS OR MATERIAL CHANGE REPORTS

5.1. Identification of TFE Requests or Material Change Reports

5.1.1. Upon receipt of a TFE Request or Material Change Report, the Regional Entity (i) will assign a unique identifier to the TFE Request~~, and (ii) will review the TFE Request to determine that the TFE Request is for an Applicable Requirement and that all Required Information has been provided~~ or Material Change Report.

5.1.2. The unique identifier assigned to the TFE Request or Material Change Report will be in the form of XXXX-YYY-TFEZZZZZ, where "XXXX" is the year in which the TFE Request is received by the Regional Entity (*e.g.*, "2009"); "YYY" is the acronym for the Regional Entity within whose Region the Covered Asset is located[4]; and "ZZZZZ" is the sequential number of the TFE Requests received by the Regional Entity in that year. ~~If~~In the ~~TFE Request is amended or resubmitted~~case of a Material Change Report, "-AZ" will be added to the end of the identifier, where "Z" is the number of the ~~amendment~~Material Change Report to the TFE ~~Request~~.

5.2 ~~Substantive~~ Review of TFE Request or Material Change Report for Approval or Disapproval

5.2.1 The Regional Entity shall ~~conduct a substantive~~ review ~~of~~ a TFE Request or Material Change Report to determine if it should be approved in accordance with Section 3.1 of this Appendix, or disapproved. ~~The Regional Entity will conduct the substantive review in accordance with established compliance monitoring processes under the CMEP, such as a Compliance Audit or Spot Check. The compliance monitoring activity may be conducted solely for the purpose of substantive review of the TFE Request, or may include review of the Responsible Entity's compliance with other Reliability Standards. As part of its substantive~~ As part of its review, the Regional Entity may request access to and review the Required Information, including any Confidential Information, Classified National Security Information, NRC Safeguards Information, and Protected FOIA Information that is necessary to support the TFE Request; may conduct one or more physical inspections of the Covered Asset(s) and the related Facility(ies); may request additional information from the Responsible Entity; and may engage in discussions with the Responsible Entity concerning possible revisions to the TFE Request or Material Change Report.

5.2.2. The Regional Entity shall complete its ~~substantive~~ review of the TFE Request or Material Change Report and make its determination of whether the TFE Request or Material Change Report is approved or disapproved, and issue a notice (in accordance with Sections 5.2.4 or 5.2.5) stating the TFE Request is approved or disapproved, within ~~one (1) year~~60 days after receipt of the TFE Request. In addition, the Regional Entity may extend the ~~one-year~~60-day time period for individual TFE Requests or Material Change Reports by issuing a notice to the Responsible Entity, with a copy to NERC, stating the revised date by which the Regional Entity will issue its notice approving or disapproving the TFE Request or Material Change Report.

5.2.3. The Regional Entity may approve or disapprove the TFE Request or Material Change Report in whole or in part, even if the TFE Request or Material Change Report is for two

[4] The acronyms to be used are: FRCC (Florida Reliability Coordinating Council); MRO (Midwest Reliability Organization); NPCC (Northeast Power Coordinating Council); RFC (Reliability*First* Corporation); SERC (SERC Reliability Corporation); SPP (Southwest Power Pool Regional Entity); TRE (Texas Regional Entity/Texas Reliability Entity); and WECC (Western Electricity Coordinating Council).

or more Covered Assets subject to the same Applicable Requirement or if it covers class-based categories of devices.

5.2.4. If the Regional Entity approves the TFE Request or Material Change Report, the Regional Entity shall issue a notice to the Responsible Entity, with a copy to NERC, stating that the TFE Request or Material Change Report is approved.

5.2.5. If the Regional Entity disapproves the TFE Request or Material Change Report, the Regional Entity shall issue a notice to the Responsible Entity, with a copy to NERC, stating that the TFE Request ~~is approved.~~or Material Change Report is disapproved and stating the reasons for the disapproval. In its notice disapproving a TFE Request, the Regional Entity may also, but is not required to, state any revisions to the TFE Request the Regional Entity has identified, based on its review of the TFE Request, that, if made by the Responsible Entity, would result in approval of the TFE Request. Such revisions may include, but are not limited to, changes to the Responsible Entity's proposed (i) compensating measures and/or mitigating measures, (ii) implementation schedules, or (iii) Expiration Date.

~~**5.2.5.** If the Regional Entity disapproves the TFE Request, the Regional Entity shall issue a notice to the Responsible Entity, with a copy to NERC, stating that the TFE Request is disapproved and stating the reasons for the disapproval.~~

5.2.6. A notice disapproving a TFE Request or Material Change Report shall state an Effective Date, which shall be no less than sixty-one (61) calendar days and no more than ninety-one (91) calendar days after the date of issuance of the notice, unless the Regional Entity determines there are exceptional circumstances that justify a later Effective Date. If the Regional Entity determines the Effective Date should be more than ninety-one (91) calendar days after the date of issuance of the notice due to exceptional circumstances, the Regional Entity shall include a detailed statement of the exceptional circumstances in the notice. Following the Effective Date, the Responsible Entity is subject to issuance of a Notice of Alleged Violation by the Regional Entity with respect to the Applicable Requirement that was the subject of the disapproved TFE Request or Material Change Report, unless the Responsible Entity ~~(i) has submitted an amended TFE Request in accordance with Section 5.2.5, or (ii)~~ has achieved Strict Compliance with the Applicable Requirement. Provided, that if the Effective Date occurs prior to the Responsible Entity's Compliant Date for the Applicable Requirement, then the Responsible Entity is not subject to issuance of a Notice of Alleged Violation until the Compliant Date. A Notice of Alleged Violation issued with respect to the Applicable Requirement shall be processed in accordance with Sections 5.0, 6.0 and 7.0 of the CMEP.

5.2.7 Within thirty (30) calendar days after issuing a notice approving or disapproving a TFE Request or Material Change Report, the Regional Entity shall submit a report to NERC setting forth the basis on which the Regional Entity approved or disapproved the TFE Request~~.~~ or Material Change Report. If the Regional Entity has disapproved the TFE Request or Material Change Report and determined there were exceptional circumstances justifying an Effective Date more than ninety-one (91) days after the date of issuance of the notice, the Regional Entity's report to NERC shall include a description of such exceptional circumstances.

5.2.8 A Responsible Entity may submit to NERC information that the Responsible Entity believes demonstrates that the approval or disapproval by a Regional Entity of a TFE Request or Material Change Report submitted by the Responsible Entity constitutes an inconsistent application of the criteria specified in Section 3.1 as compared to other determinations of TFE Requests or Material Change Reports made by the same Regional Entity or another Regional Entity for the same type of Covered Assets, and with such submission may suggest that NERC request the Regional Entity to reconsider its approval or disapproval of the TFE Request~~.~~ or Material Change Report. A Responsible Entity's submission to NERC under this Section 5.2.8 shall be in writing and shall set forth (i) the TFE Request or Material Change Report for which the Responsible Entity received a determination that the Responsible Entity believes represents an inconsistent application of the criteria specified in Section 3.1 (using the identifier assigned to the TFE Request or Material Change Report pursuant to Section 5.1.2), (ii) a copy of the Regional Entity's notice of approval or disapproval of the TFE Request or Material Change Report, and (iii) a description of the inconsistency in determinations that the Responsible Entity believes has occurred, including specific reference(s) to any other determinations of TFE Requests or Material Change Reports for the same type of Covered Assets that the Responsible Entity believes constitutes inconsistent application of the criteria specified in Section 3.1. The Responsible Entity's submission shall provide a clear and compelling demonstration that inconsistent applications of the criteria specified in Section 3.1 have occurred in the determinations of two or more TFE Requests or Material Change Reports for the same type of Covered Assets made by the same Regional Entity or two or more Regional Entities. NERC will provide a copy of the Responsible Entity's submission to the Regional Entity that approved or disapproved the TFE Request or Material Change Report that is the subject of the submission. NERC will review the Responsible Entity's submission and the reports submitted by the Regional Entity or Regional Entities pursuant to Section 5.2.7 with respect to the TFE Requests or Material Change Reports that are the subject of the Responsible Entity's submission, and may decide, in accordance with Section 5.2.9, to request the Regional Entity to reconsider its determination. NERC will send a written notice to the Responsible Entity stating that NERC has determined to request reconsideration by the Regional Entity or has determined not to request reconsideration by the Regional Entity, as applicable.

5.2.9 NERC may request the Regional Entity to reconsider the approval or disapproval of a TFE Request or Material Change Report, solely on the grounds that the approval or disapproval would result in inconsistent application of the criteria specified in Section 3.1 as compared to determinations made on TFE Requests or Material Change Reports for the same type of Covered Assets by the same Regional Entity or a different Regional Entity. Requests for reconsideration on any other grounds are not allowed. A request for reconsideration shall be submitted in writing to the Regional Entity and shall set forth (i) the TFE Request or Material Change Report that is the subject of the request for reconsideration (using the identifier assigned to the TFE Request or Material Change Report pursuant to Section 5.1.2), (ii) a copy of the Regional Entity's notice of approval or disapproval of the TFE Request or Material Change Report, and (iii) a description of the inconsistency in determinations on which NERC relies as the basis for the request for reconsideration, including specific reference(s) to other determinations of TFE Requests or Material Change Reports for the same type of Covered Asset that NERC believes constitutes inconsistent application of the criteria specified in Section 3.1. The Regional Entity shall consider the request for reconsideration and shall issue a notice to

NERC and the affected Responsible Entity(ies) approving, disapproving or rejecting the TFE Request or Material Change Report in accordance with ~~Section 5.1.4, Section 5.1.5,~~ Section 5.2.4, Section 5.2.5, Section 5.2.6 and/or Section 9.2, as applicable, within one hundred twenty (120) days following receipt of the request for reconsideration. A determination on a request for reconsideration approving or disapproving a TFE Request or Material Change Report shall be effective prospectively only, from its Effective Date, provided, that if a Regional Entity receives a request for reconsideration of the disapproval of a TFE Request or Material Change Report prior to the Effective Date of the notice of disapproval, the Regional Entity shall issue a notice to the affected Responsible Entity pursuant to Section 5.~~1.5 or Section 5.~~2.6, as applicable, suspending the Effective Date pending determination of the request for reconsideration.

5.3 No Findings of Violations or Imposition of Penalties for Violations of an Applicable Requirement for the Period a TFE Request or Material Change Report is Being Reviewed

The Responsible Entity shall not be subject to imposition of any findings of violations, or imposition of Penalties or sanctions for violations, for failure to be in Strict Compliance with an Applicable Requirement that is the subject of a TFE Request or Material Change Report, for the period from:

(i) the date that is sixty (60) calendar days after submission of the TFE Request or Material Change Report,

to:

(ii) (A) the date of the Regional Entity's notice that the TFE Request or Material Change Report is approved, or (B) the Effective Date of the Regional Entity's notice that the TFE Request or Material Change Report is disapproved, whichever is applicable.

Provided, that:

(1) while a TFE Request or Material Change Report is undergoing review, the Regional Entity shall not issue a Notice of Alleged Violation to the Responsible Entity for being noncompliant with the Applicable Requirement that is the subject of the TFE Request or Material Change Report during the period on and after the TFE Request or Material Change Report was submitted;

(2) if the TFE Request or Material Change Report is approved, the Responsible Entity shall not be subject to imposition of any findings of violations, or imposition of Penalties or sanctions for violations, for failure to be in Strict Compliance with an Applicable Requirement that is the subject of the TFE Request or Material Change Report, during the period from submission of the TFE Request to the date of the Regional Entity's notice that the TFE Request or Material Change Report is approved; and

(3) if the TFE Request or Material Change Report is disapproved, and is found by the Regional Entity, NERC or FERC to have been fraudulent or submitted not in good faith, the provisions of this Section 5.3 shall not apply, the Responsible Entity shall be subject to imposition of findings of violations and imposition of Penalties or sanctions for violations, for failure be in Strict Compliance with the Applicable Requirement that was the subject of the TFE Request or Material Change Report, for the entire period subsequent to the date the TFE Request or Material Change Report was submitted, and the Responsible Entity's fraudulent or not-in-good-faith submission of the TFE Request or Material Change Report shall be an aggravating factor in determining the amounts of Penalties or sanctions to be imposed on the Responsible Entity for such violations.

6.0 IMPLEMENTATION AND REPORTING BY THE RESPONSIBLE ENTITY PURSUANT TO AN APPROVED TFE OR MATERIAL CHANGE REPORT

6.1. The Responsible Entity will be required to implement compensating measures and/or mitigating measures as described, and in accordance with the time schedule(s) set forth, in the approved TFE.

6.2. In the event the TFE has been approved with an Expiration Date, the Responsible Entity will be required to implement steps, or conduct research and analysis, towards achieving Strict Compliance with the Applicable Requirements and eliminating the TFE, as described, and in accordance with the time schedule set forth, in the approved TFE.

6.3. [Deleted]
6.4. [Deleted]

6.5. If there is a Material Change in the facts underlying approval of the TFE, the Responsible Entity shall submit a report to the Regional Entity supporting the continuing need and justification for the approved TFE or verifying that the Responsible Entity has achieved Strict Compliance with the Applicable Requirement~~. The Material Change Report shall be submitted as an amendment to the initial TFE request~~ pursuant to Section 4.0.

~~**6.6.** Each Material Change Report shall include a statement, signed and dated by the Senior Manager or Delegate, that the Senior Manager or Delegate has read, and approved the submission of, the report.~~

~~**6.7.** The Regional Entity shall issue an acknowledgement notice to the Responsible Entity and to NERC that a report has been received, but no other issuances shall be required from the Regional Entity in response to submission of such a report.~~

6.6 [Deleted]

6.7 [Deleted]

6.8. If a Responsible Entity fails to implement or maintain a compensating measure or mitigating measure or fails to conduct research or analysis towards achieving Strict Compliance, in accordance with the approved TFE; or fails to submit one or more reports by the required submission date, the Responsible Entity (i) is required to file a Self-Report in accordance with Section 3.5 of the CMEP, and (ii) will be subject to issuance of a Notice of Alleged Violation for noncompliance with the Applicable Requirement that is the subject of the approved TFE. Any such Notice of Alleged Violation shall be processed in accordance with Sections 5.0, 6.0 and 7.0 of the CMEP.

7.0 AMENDMENT OF A PENDING TFE REQUEST ~~OR APPROVED TFE~~

7.1. Amendment of a Pending TFE Request

A Responsible Entity may amend a pending TFE Request that is under review by a Regional Entity, for the purpose of providing additional or revised Required Information during the 60-day review period. Submission of an amendment to a pending TFE Request may, in the Regional Entity's discretion, extend the time period for the Regional Entity's review of the TFE Request but does not require the restart of the approval process.

~~**7.2. Amendment of an Approved TFE**~~

~~**7.2.1.** A Responsible Entity may submit an amendment to an approved TFE for the purpose of requesting revision to any of the requirements specified in the approved TFE, such as, for example, revisions to the specific compensating measures and/or mitigating measures to be implemented, revisions to the schedule for implementing the compensating measures and/or mitigating measures, or a change in the Expiration Date. The Responsible Entity shall include a written explanation of the amendment, the reason for and purpose of the amendment, and the reason the requirements in the approved TFE should be revised.~~

~~**7.2.2.** The Regional Entity shall review the amendment to determine if the amended TFE Request should be approved or disapproved, and shall issue a notice of approval or disapproval, in accordance with Section 5.2. If the Regional Entity determines the amendment should be approved, the TFE as amended replaces the previously approved TFE.~~

8.0 COMPLIANCE AUDIT REQUIREMENTS RELATING TO APPROVED TFE

8.1. Following approval of a Responsible Entity's TFE Request, subsequent Compliance Audits of the Responsible Entity may include audit of (i) the Responsible Entity's implementation and maintenance of the compensating measures and/or mitigating measures specified in the approved TFE, in accordance with the time schedule set forth in the approved TFE, and (ii) the Responsible Entity's implementation of steps and conduct of research and analyses towards achieving Strict Compliance with the Applicable Requirement, in accordance with the time schedule set forth in the approved TFE. These topics shall be included in such

Compliance Audits regardless of whether a Compliance Audit was otherwise scheduled to include the CIP Standard that includes the Applicable Requirement.

8.2 The first Compliance Audit of the Responsible Entity subsequent to the Expiration Date shall include audit of the Responsible Entity's Strict Compliance with the Applicable Requirement that was the subject of the approved TFE. This topic shall be included in such Compliance Audit regardless of whether it was otherwise scheduled to include the CIP Standard that includes the Applicable Requirement.

9.0 TERMINATION OF AN APPROVED TFE

9.1. An approved TFE shall remain in effect unless it terminates on its Expiration Date, it is terminated at an earlier date pursuant to this Section 9.0, the Responsible Entity achieves Strict Compliance with the Applicable Requirement or there is a material misrepresentation by the Responsible Entity as to the facts relied upon by the Regional Entity in approving the TFE.

9.2. The Responsible Entity may terminate an approved TFE by submitting a notice to the Regional Entity stating that the Responsible Entity is terminating the TFE and the Effective Date of the termination.

9.3. A Regional Entity or NERC may terminate an approved TFE based on the results of a Spot Check initiated and conducted pursuant to the CMEP to determine whether the approved TFE should be terminated prior to its Effective Date or should be revised to impose additional or different requirements or to advance the Expiration Date to an earlier date. Following issuance to the Responsible Entity of a draft Spot Check report concluding that the approved TFE should be terminated or revised (including by advancement of the Expiration Date), and opportunity for the Responsible Entity to submit comments on the draft Spot Check report, the Regional Entity or NERC, if it has determined that the approved TFE should be terminated or revised, shall issue a notice of termination to the Responsible Entity (with a copy to NERC if the notice is issued by the Regional Entity) stating the Effective Date of termination of the approved TFE. The Effective Date shall be no less than sixty-one (61) calendar days and no more than ninety-one (91) calendar days after the date of issuance of the notice of termination, unless the Regional Entity determines there are exceptional circumstances that justify a later Effective Date. If the Regional Entity determines the Effective Date should be more than ninety-one (91) calendar days after the issuance of the notice of termination due to exceptional circumstances, the Regional Entity shall include a detailed statement of the exceptional circumstances in the notice of termination.

9.4. The Responsible Entity shall not be subject to imposition of any findings of violations, or imposition of Penalties or sanctions for violations, for failure to be in Strict Compliance with an Applicable Requirement that is the subject of a TFE that has been terminated, until the Effective Date of the notice of termination.

10.0 ~~[Deleted]~~ HEARINGS AND APPEALS PROCESS FOR RESPONSIBLE ENTITY

The Responsible Entity may raise issues relating to the disapproval of its TFE Request or the termination of the approved TFE in the hearing concerning the Notice of Alleged Violation, proposed Penalty or sanction, or Mitigation Plan components.

11.0 CONSISTENCY IN APPROVAL AND DISAPPROVAL OF TFE REQUESTS AND MATERIAL CHANGE REPORTS

11.1. NERC and the Regional Entities will engage in the activities specified in this Section 11.0 for the purpose of assuring consistency in the review, approval and disapproval of TFE Requests and Material Change Reports (i) among the Regional Entities, (ii) among different types of Covered Assets that are subject to the same Applicable Requirement, (iii) with respect to the application of the criteria specified in Section 3.1 for approval of TFE Requests or Material Change Reports, including the comparison of safety risks and costs of Strict Compliance to reliability benefits of Strict Compliance, and (iv) with respect to the types of mitigating measures and compensating measures that are determined to be appropriate to support approval of TFE Requests. or Material Change Reports. In appropriate cases, NERC will submit a request for reconsideration to a Regional Entity in accordance with Section 5.2.9.

11.2. The activities in which NERC and the Regional Entities will engage for the purposes stated in Section 11.1 will include, but not be limited to, the following activities:

1. [Deleted]
2. NERC will maintain, as Confidential Information, based on reports submitted by Regional Entities, a catalogue of the types of Covered Assets for which TFE Requests or Material Change Reports from the various Applicable Requirements have been approved and disapproved. The catalogue will be accessible to the Regional Entities for their use in connection with their substantive reviews of TFE Requests or Material Change Reports.

3. NERC and the Regional Entities will form a committee comprised of NERC and Regional Entity representatives involved in the review of TFE Requests or Material Change Reports and other Critical Infrastructure program activities, which shall be charged to review approved and disapproved TFE Requests or Material Change Reports for consistency and to issue such guidance to the Regional Entities, as Confidential Information, as the committee deems appropriate to achieve greater consistency in approval and disapproval of TFE Requests or Material Change Reports in the respects listed in Section 11.1. The committee shall include persons with appropriate subject matter expertise for the responsibilities and activities of the committee.

4. NERC will submit to the FERC and to other Applicable Governmental Entities an annual informational report containing the following information concerning the manner in which Regional Entities have made determinations to approve or disapprove TFE Requests or Material Change Reports based on the criteria of Section 3.1:

(i) whether any issues were identified during the period covered by the informational report with respect to the consistency of the determinations made based on the criteria in Section 3.1, either within a Regional Entity or among Regional Entities;

(ii) a description of any such identified consistency issues;

(iii) how each consistency issue was resolved;

(iv) the numbers of TFE Requests or Material Change Reports for which reconsideration was requested pursuant to Section 5.2.9 based on purported inconsistencies in determinations applying the criteria in Section 3.1 and the numbers of such requests which resulted in TFE Requests or Material Change Reports being approved or disapproved; and

(v) whether NERC has developed or is in a position to develop a uniform framework for Regional Entities to use to appraise the reliability benefits of Strict Compliance when making determinations based on the criteria in Section 3.1(iv) and (vi).

The first such informational report shall cover the period through June 30, 2011, and shall be filed with FERC and other Applicable Governmental Entities no later than September 28, 2011. Subsequent annual informational reports shall cover the period from July 1 through June 30 and shall be filed within 90 days following the end of the period covered by the report.

If NERC determines it is necessary to include any Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information in an informational report in order to satisfy the information requirements specified above, such Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information shall be contained in a separate non-public, confidential appendix to the informational report. Prior to submitting to FERC or another Applicable Governmental Authority a non-public, confidential appendix that provides specific Confidential Information, Classified National Security Information, NRC Safeguards Information, or Protected FOIA Information of a particular Responsible Entity and identifies the Responsible Entity or one of its Facilities by name, NERC shall provide at least twenty-one (21) days advance notice to the Responsible Entity. The non-public, confidential appendix shall be submitted to FERC and other Applicable Governmental Authorities in accordance with their procedures for receiving confidential, proprietary and other protected information.

12.0 CONFIDENTIALITY OF TFE REQUESTS, MATERIAL CHANGE REPORTS AND RELATED INFORMATION

Except as expressly stated in this Section 12.0, the submission, review, and approval/disapproval of TFE Requests or Material Change ReportS, and the implementation and termination of approved TFEs, shall be maintained as confidential. The following Documents are Confidential Information and shall be treated as such in accordance with Section 1500 of the NERC *Rules of Procedure*:

(i) All TFE Requests and ~~proposed~~ amendments or Material Change Reports submitted, filed or made available by the Responsible Entity;

(ii) All notices issued by a Regional Entity or NERC pursuant to this Appendix;

(iii) All requests for Documents or information made by a Regional Entity or NERC pursuant to this Appendix;

(iv) All submissions of Documents and information by a Responsible Entity to a Regional Entity or NERC pursuant to this Appendix;

(v) All post-approval reports submitted by a Responsible Entity pursuant to this Appendix;

(vi) All correspondence, notes, drawings, drafts, work papers, electronic communications, reports and other Documents generated by a Regional Entity or NERC in connection with a TFE Request or Material Change Report, including (without limiting the scope of this provision) in connection with reviewing a TFE Request or Material Change Report and supporting Documents and information submitted, filed or made available by the Responsible Entity, conducting a physical inspection of the Covered Asset(s) or the related Facility(ies), reviewing and analyzing post-approval reports submitted by a Responsible Entity, or conducting compliance monitoring processes pursuant to the CMEP with respect to a TFE Request or Material Change Report or approved TFE.

(vii) All guidance issued to Regional Entities pursuant to Section 11.2 by NERC or by the committee described in Section 11.2(3), and all minutes of meetings of the committee and discussions between or among its members.

(viii) All submissions by Responsible Entities to NERC pursuant to Section 5.2.8.

(ix) All requests for reconsideration pursuant to Section 5.2.9.

(x) Any confidential appendix to an informational report prepared and submitted pursuant to Section 11.2(4) or to an Annual Report prepared and submitted pursuant to Section 13.0.

13.0 ANNUAL REPORT TO FERC AND OTHER APPLICABLE GOVERNMENTAL AUTHORITIES

13.1. Contents of Annual Report

NERC shall submit an Annual Report to FERC that provides a Wide-Area analysis or analyses, which NERC shall prepare in consultation with the Regional Entities, regarding the use of TFEs and the impact on the reliability of the Bulk Electric System, as required by Paragraphs 220 and 221 of *Order No. 706*, which state:

> . . . [W]e direct the ERO to submit an annual report to the Commission that provides a wide-area analysis regarding use of the technical feasibility exception and the effect on Bulk-Power System reliability. The annual report must address, at a minimum, the frequency of the use of such provisions, the circumstances or justifications that prompt their use, the interim mitigation measures used to address vulnerabilities, and efforts to eliminate future reliance on the exception. . . [T]he report should contain aggregated data with sufficient detail for the Commission to understand the frequency with which specific provisions are being invoked as well as high level data regarding mitigation and remediation plans over time and by region . . . .

Copies of the Annual Report shall be filed with other Applicable Governmental Authorities. The Annual Report shall contain, at a minimum, the following information:

(i) The frequency of use of the TFE Request process, disaggregated by Regional Entity and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, including (A) the numbers of TFE Requests that have been submitted and approved/disapproved during the preceding year and cumulatively since the effective date of this Appendix, (B) the numbers of unique Covered Assets for which TFEs have been approved, (C) the numbers of approved TFEs that are still in effect as of on or about the date of the Annual Report; (D) the numbers of approved TFEs that reached their Expiration Dates or were terminated during the preceding year; and (E) the numbers of approved TFEs that are scheduled to reach their Expiration Dates during the ensuing year;

(ii) Categorization of the submitted and approved TFE Requests to date by broad categories such as the general nature of the TFE Request, the Applicable Requirements covered by submitted and approved TFE Requests, and the types of Covered Assets that are the subject of submitted and approved TFE Requests;

(iii) Categorization of the circumstances or justifications on which the approved TFEs to date were submitted and approved, by broad categories such as the need to avoid replacing existing equipment with significant remaining useful lives, unavailability of suitable equipment to achieve Strict Compliance in a timely manner, or conflicts with other statutes and regulations applicable to the Responsible Entity;

(iv) Categorization of the compensating measures and mitigating measures implemented and maintained by Responsible Entities pursuant to approved TFEs, by

broad categories of compensating measures and mitigating measures and by types of Covered Assets;

(v) For each TFE Request that was disapproved, and for each TFE that was terminated, but for which, due to exceptional circumstances as determined by the Regional Entity, the Effective Date was later than the latest date specified in Section 5.2.6, or 9.3, as applicable, a statement of the number of days the Responsible Entity was not subject to imposition of findings of violations of the Applicable Requirement or imposition of Penalties or sanctions pursuant to Section 5.3.

(vi) A discussion, on an aggregated basis, of Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures, and the implementation of steps and the conduct of research and analyses to achieve Strict Compliance with the Applicable Requirements, by Responsible Entities in accordance with approved TFEs;

(vii) Assessments, by Regional Entity (and for more discrete areas within a Regional Entity, if appropriate) and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, of the Wide-Area impacts on the reliability of the Bulk Electric System of approved TFEs in the aggregate, including the compensating measures and mitigating measures that have been implemented; and

(viii) Discussion of efforts to eliminate future reliance on TFEs.

13.3. Due Date for Annual Reports

The first Annual Report shall cover the period through June 30, 2011, and shall be filed with FERC and with other Applicable Governmental Authorities no later than 90 days after the end of such calendar quarter. Subsequent Annual Reports shall be filed at one year intervals thereafter.

13.4. Annual Report to be a Public Document; Confidential Appendix

It is the intent of this Appendix that the Annual Report be a public document. Therefore, NERC shall prepare the annual report in such a manner that it does not include or disclose any Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information. However, if NERC determines it is necessary to include any Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information in an Annual Report in order to satisfy the information requirements specified in this Appendix or required by FERC or other Applicable Governmental Authorities, such Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information shall be contained in a separate non-public, confidential appendix to the Annual Report. Prior to submitting to FERC or another Applicable Governmental Authority a non-public, confidential appendix that provides specific Confidential Information, Classified National Security Information, NRC Safeguards Information, or Protected FOIA Information of a particular Responsible Entity and identifies the

Responsible Entity or one of its Facilities by name, NERC shall provide at least twenty-one (21) days advance notice to the Responsible Entity. The non-public, confidential appendix shall be submitted to FERC and other Applicable Governmental Authorities in accordance with their procedures for receiving confidential, proprietary and other protected information.

13.5. Responsible Entities Must Cooperate in Preparation of Annual Report

As specified in Paragraph 220, note 74 of Order No. 706, Responsible Entities must cooperate with NERC and Regional Entities in providing information deemed necessary for NERC to fulfill its reporting obligations to FERC.

Summary of Proposed Amendments to the Technical Feasibility Exception Process in the NERC Rules of Procedure, Appendix 4D

Set forth in this summary are:

(i) information about the background and process used in developing the proposed ROP amendments (the Background and Process section);
(ii) a summary of the proposed amendments (the Principal Revisions section);
(iii) a summary of the stakeholder comments received on the proposed amendments after the October 5, 2012 posting of such proposed amendments (the Principal Comments and Clarifications section); and
(iv) a detailed summary of the proposed amendments on a section-by-section basis (the Section by Section Revisions section).

Attached to this summary are:

(i) a cumulative redline showing the proposed amendments compared to the currently effective ROP text; and
(ii) an incremental redline showing changes made in response to the comments received from stakeholders.

Background and Process

The Regional Entities and NERC have worked collaboratively to develop proposed revisions to Appendix 4D to the NERC Rules of Procedure to streamline the process for approving technical feasibility exceptions (TFEs) to Critical Infrastructure Protection (CIP) Reliability Standards.

The proposed revisions to Appendix 4D represent a significant improvement to the current TFE process that will allow resources to be refocused on activities that can directly impact reliability, and decrease administrative tasks.

The Regional Entities have led the efforts to review and restructure the TFE process since January 2012. The goal was to evaluate and realign the burden and benefits associated with the TFE process. Over a period of several months, the technical experts at each Regional Entity developed the initial concept for streamlining the TFE process. Certain Regional Entities also presented the streamlining proposal to various industry stakeholders in trade conferences and meetings. Throughout the process, industry stakeholders have provided feedback, suggestions, and concerns, which were considered as the proposal was refined. There is broad support for the streamlining concept. NERC staff and the Regional Entities worked to develop the specific proposed changes to Appendix 4D attached hereto, which were most recently discussed with

industry representatives during an in person meeting at NERC in October 2012, ahead of the posting period.

The proposed revisions to Appendix 4D draw upon the experience gained to date by the Regional Entities' staff tasked with processing large numbers of TFE requests during the last two years.[1] When Appendix 4D was originally developed, Regional Entities and registered entities had minimal experience as to the types of issues that would arise in connection with TFE requests, including associated risks and vulnerabilities, and the amount and nature of information needed to substantiate TFE requests. Experience has shown that the majority of the TFE requests relate to low-risk issues, have common rationales and justification, are supported by common evidence, and often involve similar devices across registered entities nationwide. Because of this experience, the administrative burden associated with the current process is no longer justified when weighed against the benefits to reliability afforded by the current process.

The proposed revisions were posted on the NERC website for comments on October 5, 2012. NERC held a webinar to discuss the proposed revisions and answer questions on October 31, 2012. Originally, the deadline for comments was November 19, 2012. At the request of a number of industry stakeholders, the comment deadline was postponed until November 27, 2012. The proposed changes were also on the agenda for the NERC Members Representative Committee meeting in November 2012 when they were discussed and reviewed.

This summary and accompanying materials were posted on the NERC website on January 14, 2013, fifteen days prior to consideration of these revisions by the board, as contemplated in NERC's process for proposed revisions to the Rules of Procedure.

Principal Revisions

The principal feature of the proposed revisions is the elimination of the two-phased (Part A and Part B) TFE request. Currently, the TFE request process includes a preliminary screening phase (Part A) and a substantive review phase (Part B). Regional Entities have accumulated a significant database of materials used to justify TFE requests and compensating and mitigating measures associated with a number of devices. Because many types of TFE requests and related substantiation materials are similar in nature, Regional Entities are currently able to consolidate the two phases in the current process into one simplified step for gathering the information associated with a TFE request.

In the majority of cases, the Regional Entity is expected to be able to approve the TFE in 60 days, based on the information provided by the registered entity as well as the Regional Entity's knowledge and accumulated information about the type of device in question. The Regional

[1] Over the first several months of the program, more than 5,000 TFE requests were submitted. *See* Annual Report of the North American Electric Reliability Corporation on Wide-Area Analysis of Technical Feasibility Exceptions, Docket No. RR10-1-001 (September 28, 2011).

Entity would retain the ability to request additional information or extend the review period if, for example, a novel type of device is involved. Any necessary verification would be performed, at the Regional Entity's discretion, through an audit or spot check (including a regularly scheduled audit, for example). Thus, the proposed revisions balance the need to streamline the TFE review process and eliminate burden with the need for information.

In addition, the proposal shortens the overall processing time for TFE requests. The proposal also eliminates the periodic reporting requirements applicable to registered entities and replaces them with a Material Change Report to be submitted only if and when the facts underlying a TFE request change.

The proposal addresses primarily the processing of TFEs. No changes to the criteria for approving TFEs are being proposed, although the method for analyzing whether the existing criteria has been met is modified as indicated above. The requirements related to the development of compensating and mitigating measures are not affected. The availability of a safe harbor period during the pendency of the request and for a subsequent period, in the event of a disapproved TFE, also remains. Finally, the proposed changes will continue to ensure that sufficient information associated with TFE requests remains available to NERC and the appropriate regulatory authorities. A section-by-section explanation of the revisions is provided below.

Principal Comments and Clarifications

The majority of commenters strongly supports the initiative of streamlining the processing of TFEs. Most of the commenters focused on requesting clarification of the new procedures, in particular, the process for reporting a Material Change. Commenters also requested clarification regarding the transition from the existing procedures to the proposed streamlined procedures. These clarifications were provided through additional revisions in Appendix 4D, shown in the incremental redline of Appendix 4D, and in the matrix attached to these materials.

Also, as part of the clarifications provided, a sample TFE request was provided through a link to the NERC website. The information to be collected through the TFE request (and Material Change Report) is specified in section 4.2 (as revised pursuant to the comments received) and will be the same in each Regional Entity footprint. No evidence will be submitted, unless specifically requested by the Regional Entity.

Regarding the transition from the existing process to the proposed revisions, at the time of the first (a) initial TFE request or (b) Material Change Report that is required to be submitted after approval of the proposed revisions, a registered entity would submit a complete TFE submittal to reflect existing TFEs as well as the new information. This one-time submittal would be followed by the maintenance of this document, either through additional TFE requests or Material Change Reports pertaining to TFE requests already approved. The submittal of this baseline TFE document would not reopen any TFEs already approved under the existing Appendix 4D process or restart the review process of pending TFEs.

Material Change Reports will be used to communicate and, as necessary, seek approval for changes to an approved TFE. The new Material Change Report process would mirror the streamlined process for submitting TFEs and would be reviewed within the same timeframe. The circumstances that would trigger the need for a Material Change Report were also clarified.

A registered entity would be allowed to amend a pending TFE request as needed during the 60 day review period without restarting the review process.

The new streamlined reporting requirements will apply to all previously approved TFEs.

Section-by-Section Revisions

Section 2.11 – References to "rejecting" and "rejection" of a TFE request were deleted in this section and throughout the document to reflect the consolidation of the screening and substantive review phases of the TFE process. Under the proposed revisions, TFE requests would no longer be subject to acceptance or rejection but rather approval or disapproval.

New sections 2.17 and 2.18 – The defined terms "Material Change" and "Material Change Report" were added to reflect a streamlined reporting requirement for changes to an approved TFE request. In response to comments, these definitions were further revised for clarity.

Old sections 2.19 and 2.20 – The defined terms "Part A Required Information" and "Part B Required Information" were deleted to reflect the new format of the TFE request, which is consolidated into a single submittal.

Section 3.4 – This section was revised to reflect the new process for modifying an approved TFE through a Material Change Report.

Section 4.0 – In response to comments, further revisions were made throughout this section to reflect the fact that the process for a Material Change Report is essentially identical to that of a TFE request.

Section 4.1 – This section was revised to reflect the possibility of submitting class-based TFE requests. In addition, language was deleted to allow Regional Entities to collaborate on approval of TFE requests for entities located in multiple Regional Entity footprints.

Sections 4.2 and 4.3 – These sections were revised to reflect the new format and Required Information associated with a TFE request. While the amount of information to be submitted is greatly reduced, the Regional Entity retains the ability to seek any other information that may be necessary or appropriate. In addition, the new language authorizes the Regional Entity to verify any information at a subsequent audit, spot check or other form of compliance monitoring. The TFE request would no longer involve a initial screen followed by a substantive review (former Parts A and B). Rather, the review would be performed on the basis of the

consolidated TFE request, with substantiation to follow through a compliance monitoring and enforcement program (CMEP) process. In response to comments, additional detail was provided with respect to the Required Information, form of submittal, events that would trigger the need for a Material Change Report, the process for transitioning to the new submittal format as well as the requirement for signature by a senior manager or delegate which had been inadvertently omitted from the original posting of the revisions.

Section 4.4.1 – This section was revised to reflect the elimination of Part B of the TFE Request.

Section 4.5 – This section was eliminated because it was not necessary. The extent of the safe-harbor protection is already defined in section 5.3, which provides an incentive for the filing of a TFE 60 days prior to the entity's Compliant Date. That provision has not been substantively revised so registered entities remain at risk for a finding of a possible violation if TFE requests are not timely submitted. Section 4.5 contained an administrative requirement for submitting TFE requests within a specified timeframe that is not needed in light of the provisions of section 5.3.

Sections 5.0 and 5.1 – The headings of the sections were modified to reflect the elimination of the screening process and consequent acceptance or rejection. In addition, in response to comments, further revisions were made throughout Section 5.0 to reflect the fact that the process for a Material Change Report is essentially identical to that of a TFE request.

Sections 5.1.1, 5.1.3-5.1.7 – These sections were revised to reflect the elimination of the Part A submittal as well as the streamlined information requirements and consolidated review and approval process for TFE requests.

Section 5.2.1 – This section was revised to reflect the elimination of the Part B submittal. In addition, the reference to Data Request was eliminated as unnecessary since CMEP processes rather than Data Requests are generally used in connection with TFE reviews.

Section 5.2.2 – This section was revised to eliminate a cross reference to a deleted section.

Section 5.2.3 – This section was revised to reflect that a TFE request can be approved in part.

Section 5.2.4 – This section was revised to reflect the fact that the process for a Material Change Report is essentially identical to that of a TFE request.

Section 5.2.5 – This section was revised to reflect the fact that the process for a Material Change Report is essentially identical to that of a TFE request. In response to comments, language allowing the Regional Entity to provide substantive feedback in connection with a disapproval was reinstated.

Sections 5.2.6 and 5.2.7 -- These sections were revised to reflect the fact that the process for a Material Change Report is essentially identical to that of a TFE request.

Sections 5.2.8 and 5.2.9 – These sections were revised to reflect the consolidation of the review process and the elimination of initial screening phase, in which the TFE request could be "rejected." This section was also revised to eliminate two cross references to deleted sections.

Section 5.3 – This section was revised to reflect the consolidation of the review process and the elimination of initial screening phase, in which the TFE request was "accepted" for further review and approval or "rejected."

Section 6.0 – In response to comments, further revisions were made throughout this section to reflect the fact that the process for a Material Change Report is essentially identical to that of a TFE request.

Section 6.2 – This section was modified to recognize that the majority of the TFE requests do not have Expiration Dates. Experience has shown that most TFEs relate to network devices and other equipment for which vendors are not pursuing versions that would allow Strict Compliance with NERC Reliability Standards and consequently, a need for an open-ended TFE exists in most cases.

Section 6.3 and 6.4 – These sections were deleted to eliminate the requirements for quarterly reports to the Regional Entity. Experience has demonstrated that these are not necessary to maintain reliability so long as the TFE remains unchanged. Under Section 13.5, however, both Regional Entities and Responsible Entities remain under the obligation to provide any information deemed necessary for NERC to fulfill its reporting obligations to FERC, and Responsible Entities have the obligation to notify Regional Entities in any Material Changes to TFEs

Section 6.5 – This section was modified to eliminate the requirement for an annual report to the Regional Entity and instead require a Material Change Report that would be submitted when an amendment to the initial TFE request occurs. Under Section 13.5, both Regional Entities and Responsible Entities remain under the obligation to provide any information deemed necessary for NERC to fulfill its reporting obligations to FERC.

Sections 6.6 and 6.7 – These sections were deleted as unnecessary given the clarification that a Material Change Report is processed in a similar manner as a TFE request.

Section 6.9 – This section was deleted because it is superseded by the introduction of the Material Change Report.

Section 7.1 – This section was modified to revise the process for changes to a pending TFE request. A Responsible Entity may make any necessary changes without restarting the TFE request process during the first sixty days of review. At the end of the sixty-day period, the Regional Entity will approve or disapprove the TFE request with the information available to it unless the Regional Entity determines that it needs additional time. This modification is

necessary to encourage complete submittals and discourage unnecessary amendments or revisions to the request that could delay the processing of the TFE request.

Sections 7.2.1, 7.2.2 and 7.2.3 – These sections were deleted because they are superseded by the introduction of the Material Change Report.

Section 8.1 – This section was revised to allow, instead of require, that a Regional Entity conduct an audit following the approval of every TFE request. The Regional Entities should retain flexibility to determine audit schedules in connection with a number of factors, only one of which would be the verification of issues associated with TFE requests. Experience has demonstrated that a number of TFE requests involve matters of low risk for which the rationales, evidence, documentation, and compensating and mitigating measures are uniform and familiar to Regional Entities and Responsible Entities alike. In some cases, verification in an audit may not be necessary.

Section 9.1 – This section was revised to clarify the circumstances in which a TFE would be terminated.

Section 10.0 – This section has been modified to eliminate language that is duplicative of the process for appealing Possible Violations under the CMEP. The term "rejection" was removed from this section to reflect the consolidation of the review process and the elimination of initial screening phase, in which the TFE request was "accepted" for further review and approval or "rejected." In response to comments, the last sentence of the provision, which clarifies that a registered entity may raise issues related to the disapproval of its TFE request in a CMEP appeal process was reinstated.

Section 11.0 – In response to comments, further revisions were made throughout this section to reflect the fact that the process for a Material Change Report is essentially identical to that of a TFE request.

Section 11.2 – This section was revised to eliminate a process that has not proven particularly useful in the context of NERC's and the Regional Entity's review of consistency in the approval and disapproval of TFE requests. Other steps, which remain in section 11.2, have been more effective in pursuing this objective.

Section 12.0 – This section has been revised to reflect the elimination of the Part A and B phases of the TFE process. In addition, in response to comments, further revisions were made throughout this section to reflect the fact that the process for a Material Change Report is essentially identical to that of a TFE request.

Section 13.1 – The term "rejection" was removed from this section to reflect the consolidation of the review process and the elimination of initial screening phase, in which the TFE request was "accepted" for further review and approval or "rejected." This section was also revised to eliminate a cross reference to a deleted section.

Section 13.2 – This section has been deleted to eliminate the requirement of a quarterly report to NERC. It is noted, however, that both Regional Entities and Responsible Entities remain under the obligation to provide any information deemed necessary for NERC to fulfill its reporting obligations to FERC.

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Media Release

NERC Releases Long-Term, Winter Reliability Assessments

November 29, 2012

WASHINGTON, DC – During the next ten years, the electricity industry faces a number of emerging reliability issues driven by transformational changes in the industry. The changes include a resource mix with more reliance on natural gas-fired generation, a reduction in coal-fired capacity, and significantly larger amounts of variable generation — mostly wind and solar – and demand-side management, according to the North American Electric Reliability Corporation's (NERC) *2012 Long-Term Reliability Assessment* released today.



NERC's annual long-term reliability assessment provides an independent, ten-year view of the electricity industry by evaluating key reliability indicators, including peak demand and energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other issues that may impact the reliability of the bulk power system. With the exception of the challenges identified in Electric Reliability Council of Texas (ERCOT) since our last report, the electricity industry has adequate plans to provide reliable electric service across North America for the 2013-2022 period.



This year's report focuses on eight key findings, which include:

- Significant fossil-fired generator retirements over next five years.
- Planning reserve margins in ERCOT lower than target.
- Favorable resource adequacy assessment for majority of areas.
- Increased dependence on natural gas for electricity generation.
- Long-term generator maintenance outages for environmental retrofits.
- Large growth in renewable resources.
- Significant transmission growth to accommodate new and distant renewable generation.
- Demand-side management offsets future resource needs.



Approximately 64 GW of fossil-fired generator retirements have either retired or will retire by 2017; the amount increases to 71 GW by 2022, the report finds. This closely

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aligns with NERC's projections from the prior year's assessment. While the amount of retirements represents a significant reduction in capacity, more than 32 GW of new gas-fired generation and 60 GW of new renewable capacity will be installed over the same period.

"The on-going changes to the resource mix will require significant adjustments to existing planning and operating practices to maintain grid reliability," said John Moura, associate director of Reliability Assessment at NERC. "In many areas across North America, the challenge to reliably accommodate a change in resource mix will require careful planning and time for necessary transmission upgrades."

Results from the resource adequacy assessment show reserve margins for the ERCOT area are below target levels. A combination of high demand growth and lower than anticipated capacity commitments cause planning reserve margins to drop below a target level of 13.75 percent by 2013.

"The long-term assessment allows NERC, the industry and policymakers to foresee how a resource overhaul dramatically affects traditional planning and design principals," Moura said. "Once identified and fully evaluated, potential challenges to reliability in the future can be considered and addressed."

To ensure reliability can be maintained, there must be continued enhancement of sophisticated modeling, a risk and probabilistic framework built to address reliability challenges, and growing physical and cyber security monitoring to ensure reliability. These emerging reliability issues, as well as others, are addressed in the report.

Also released today is NERC's *2012/2013 Winter Reliability Assessment*. The assessment is for the operating period of December 2012 through February 2013, and identified three key findings that highlight either a common theme across North America or a region-specific challenge. The findings are:

- Planning reserve margins are sufficient to accommodate normal winter weather.
- Extreme winter weather in the Northeast could lead to increased gas-fired generator outages.
- Improved winterization in the Southwest responding to the February 2011 Cold Weather Event.

"While the long-term assessment shows that industry is in the midst of change, the winter assessment presents a strong indication that some challenges in New England are already here," Moura said. "Dependence on natural gas in New England will be closely monitored this winter. More importantly, a significant amount of preparation, planning and coordination between the electricity and gas industries is proactively underway."

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The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO), certified by the Federal Energy Regulatory Commission in the United States to establish and enforce reliability standards for the bulk power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2012 Long-Term Reliability Assessment

November 2012

RELIABILITY | ACCOUNTABILITY






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This assessment was prepared by NERC in its capacity as the Electric Reliability Organization[1] and provides an independent view of the 10-year reliability outlook for the North American BPS,[2] while identifying trends, emerging issues, and potential risks. Additional insight will be offered regarding resource adequacy and operating reliability, as well as an overview of projected electricity demand growth for individual assessment areas. The 10-year period observed in this assessment is from 2013-2022, with the 2013 summer as the initial season. Information and data for the 2012 summer and 2012/2013 winter seasons are provided in NERC's seasonal reliability assessments.[3] This new approach eliminates overlap between seasonal and long-term assessments.

Additional inquiries regarding the information, data, and analysis in this assessment may be directed to the NERC Reliability Assessment Staff:

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[1] Section 39.11(b) of the U.S. FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[2] BPS reliability, as defined in the *How NERC Defines BPS Reliability* section of this report, does not include the reliability of the lower voltage distribution systems, which systems account for 80 percent of all electricity supply interruptions to end-use customers.

[3] NERC *2012 Summer Reliability Assessment* and *2012/2013 Winter Reliability Assessment*: http://www.nerc.com/page.php?cid=4|61.

Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) of North America.[4,5] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces reliability standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[6]

Reliability Standards are the planning and operating rules that electric utilities follow to support and maintain a reliable electric system. These standards are developed by the industry using a balanced, open, fair and inclusive process accredited by the American National Standards Institute (ANSI). While NERC does not have authority to set Reliability Standards for resource adequacy (e.g., reserve margin criteria) or to order the construction of resources or transmission, through reliability assessment, NERC can independently assess where reliability issues may arise as well as identify emerging risks. This information, along with NERC recommendations, is then available to policy makers and federal, state, and provincial regulators to support decision making within the electric sector.

NERC Regional Entities	
FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

NERC Regional Entities Map



NERC Assessment Areas Map



NERC prepares seasonal and long-term assessments of the overall reliability and adequacy of the North American BPS, which is divided into 26 assessment areas, both within and across the eight Regional Entity boundaries, as shown by the corresponding table and maps above.[7] To prepare these assessments, NERC collects and consolidates data from the eight Regional Entities, including forecasts for on-peak demand and energy, demand response, resource capacity, and transmission projects. The use of this bottom-up approach accounts for virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The information is analyzed to identify notable trends, emerging issues, and potential concerns regarding future electricity supply, as well as the overall adequacy of the BPS to meet future demand. Reliability assessments are developed with the intention of informing industry, policy makers, and regulators and to aid NERC in achieving its mission—to ensure the reliability of the North American BPS.

[4] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf.

[5] The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[6] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory and enforceable in that jurisdiction.

[7] A larger map of the assessment area boundaries is included in Appendix IV of this assessment.

Assessment Preparation and Design

The *2012 Long-Term Reliability Assessment* (*2012LTRA*) is published in accordance with Title 18, § 39.11 of the Code of Federal Regulations,[8] also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the BPS. NERC's obligation to produce a long-term reliability assessment is further described by Section 803 of NERC's Rules of Procedure,[9] which calls for the development of an annual long-term report with a 10-year planning horizon.

NERC prepared the *2012 Long-Term Reliability Assessment* with support from the Reliability Assessment Subcommittee (RAS), under the direction of the NERC Planning Committee (PC). This report is based on data and information submitted by each of the eight Regional Entities, which are represented on the RAS. Initial data and information was submitted in June 2012, and periodic updates occurred throughout the development of the report. Any other data sources included by NERC staff are identified accordingly.

NERC uses a RAS peer review process in preparing both seasonal and long-term reliability assessments to leverage the knowledge and experience of subject matter experts representing NERC Regions, as well as the electricity industry at large. This process provides an essential balance that ensures the validity of data and information provided by the Regional Entities. Each regional self-assessment is assigned to subcommittee members from other Regions to provide a comprehensive review that is discussed and verified by the subcommittee in open meetings. The review process enables all RAS members the opportunity to verify that each Regional Entity produces quality assessments that are accurate and offer a comprehensive assessment for each assessment area. A complete draft of the document is further reviewed by the PC and the Member Representatives Committee (MRC), fully vetting all findings and conclusions. Prior to release, the assessment is submitted to the NERC Board of Trustees (BOT) for final review and approval.

The *2012LTRA* is arranged as follows:

- An "Executive Summary" presents notable findings and highlights brought forward from NERC's reference case projections for the long-term outlook. This section also provides an overview of NERC-wide reliability issues that have been recognized by the industry as important emerging issues that need to be addressed. Additionally, highlights of the projected resource adequacy are provided for the 26 assessment areas, along with area-specific impacts and potential vulnerabilities.
- The "Key Reliability Findings" section includes highlights identified from the *2012LTRA* Reference case. The reference case incorporates known policy and regulation changes expected to take effect throughout the 10-year timeframe, assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior. This section provides NERC's independent assessment of the *2012LTRA* Reference case and recommendations to further identify, study, or manage reliability concerns.
- The "Emerging Reliability Issues in Focus" section supports the development of scenarios—the analysis of which can indicate the sensitivity of the reference case to changes in pre-specified conditions and provide insight into the risks to regional reliability. Emerging reliability issues are generally known or unknown risks NERC and its stakeholders have endorsed for assessment. Continued understandings of potential impacts to the BPS, the likelihood of those impacts, and regional implications are important characteristics to NERC's reliability assessment process.
- The "Demands, Resources, and Reserve Margins" section provides summary tables and corresponding analysis of projections of the electricity supply, demand, and transmission throughout North America.
- The "Regional Reliability Assessments" section includes summary tables and corresponding text that provide a more comprehensive and granular reliability outlook for each assessment area.

[8] http://www.gpo.gov/fdsys/pkg/CFR-2010-title18-vol1/pdf/CFR-2010-title18-vol1-sec39-11.pdf.
[9] NERC Rules of Procedure: http://www.nerc.com/page.php?cid=1|8|169.

Report and Data Assumptions

Forecasts cannot precisely predict the future. Instead, many forecasts report a baseline or "most likely" outcome and a range of possible outcomes based on probabilities around the baseline or midpoint. Each NERC Region is responsible for providing projections for NERC's seasonal and long-term reliability assessments. Projections are highly dependent on the data, methodologies, model structures, and other assumptions that often vary by Region, Reliability Coordinator, assessment area, or Balancing Authority.[10] Generally, future generation projections are often derived from generation queues and other area-specific resource planning processes, while load projections are typically based on a non-coincident 50/50 peak demand forecast probability. Additional information is available in Appendix IV and V of this assessment.

When aggregating this data to provide overall projections for the United States, Canada, or North America as a whole, NERC strives to ensure these projections are as accurate as possible to aid the industry, regulators, and policy makers.

The *2012LTRA* reference case for electricity supply and internal demand projections are as follows:

- Data updates are included until September 2012. Any subsequent revisions or corrections may not be included or otherwise represented in this assessment.
- Average or normal weather conditions.
- Based on the economic conditions and outlook at the time of analysis.
- Generating and transmission equipment availability is based on historic performance.
- Planned outages and additions to or upgrades of generation and transmission will be completed as scheduled.
- Demand reductions expected from direct control load management and interruptible demand contracts will be available if and when they are needed.
- Other peak demand-side management and demand response programs are included in net internal demand forecasts.
- Electricity transfers between Regions are contractually arranged and occur as projected.
- Federal, state, and provincial laws and regulations in effect at the time of data and information collection.

In the *2011 Long-Term Reliability Assessment*, NERC indicated that the Environmental Protection Agency's (EPA) Cross-State Air Pollution Rule (CSAPR), combined with other environmental regulations, could directly impact power supply decisions and grid reliability. On August 21, 2012, the D.C. Circuit Court vacated the CSAPR,[11] which had originally required 23 states to reduce annual SO_2 and NO_X emissions. Final data submission for this assessment may not reflect the full impact of the vacated rule. The data collected for the *2012LTRA* is generally based on the assumption that this rule would remain in effect. However, since CSAPR did not mandate physical requirements for electric generators, the rule had a smaller bearing on unit retirement decisions compared to other factors. Moreover, the likely drivers behind retirement decisions will be the combination of other federal and state environmental rules, changing fuel costs (i.e., lower natural gas prices), and other economic decisions. The status of these assumptions is represented in the reference case assessed in this report.

[10] Additional information on the methods and assumption used by each Assessment Area are available through the following link: http://www.nerc.com/files/2012LTRA_PartII.pdf.

[11] The CSAPR was initially designed to replace EPA's 2005 Clean Air Interstate Rule (CAIR). A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement Clean Air Act requirements concerning the transport of air pollution across state boundaries. This action responds to the court's concerns. For additional information see the EPA website http://www.epa.gov/airtransport/.

Enhancements

A number of enhancements have been made to the *2012 Long-Term Reliability Assessment* in support of stakeholder comments, the Reliability Assessment Improvement Plan,[12] guidance from the Board of Trustees, and the Reliability Assessment Subcommittee's efforts to obtain additional information needed to sufficiently perform the long-term reliability assessment. This year, enhancements include:

- **An enhanced view of generator retirements and retrofits**
  - A supplemental request for information and data on known and potential generator retirements and retrofits in the next 10 years (see Appendix IX for more information)
- **Probabilistic indices to supplement the *Long-Term Reliability Assessment***
  - The biannual probabilistic assessment report is designed to complement the *Long-Term Reliability Assessment* by providing additional probabilistic statistics of Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE). The analysis will provide results for the third and fifth year of the *2012 Long-Term Reliability Assessment*—2014 and 2016 results (see Appendix VIII for more information)
- **Regional vulnerabilities and emerging issues identified in the report**
  - Emerging issues are developed for each assessment area that provide a more granular view on Region-specific issues that potentially affect long-term BPS reliability
- **Risk-type evaluations of key reliability findings and emerging reliability issues**
  - Evaluations of risks to operating reliability (security) compared to those that impact resource adequacy
  - Preliminary support for the Reliability Issues Steering Committee (RISC) framework as this will evolve into future reliability assessments
- **A Regional Methods and Assumptions document**
  - A separate document is published that details methods and assumptions used in the development of the seasonal and long-term reliability assessments for each NERC Assessment Area. This information is modified only as frequently as the Assessment Area changes or enhances the process for assessing reliability. This document is published to support the *2012 Long-Term Reliability Assessment* and can be found on the NERC website.[13]
- **Modified 10-year assessment period**
  - The 10-year period observed in this assessment is from 2013-2022, with the 2013 summer as the initial season. Information and data for the 2012 summer and 2012/2013 winter seasons are provided in NERC's seasonal reliability assessments.[14] This new approach eliminates overlap between seasonal and long-term assessments.

[12] Reliability Assessment Improvement Plan : http://www.nerc.com/files/Reliability%20Improvement%20Report%20RAITF%20100208.pdf .
[13] 2012 LTRA Methods and Assumptions: http://www.nerc.com/files/2012LTRA_PartII.pdf.
[14] NERC *2012 Summer Reliability Assessment* and *2012/2013 Winter Reliability Assessment*: http://www.nerc.com/page.php?cid=4|61.

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Executive Summary

In preparing this assessment, NERC has evaluated key reliability indicators, including peak demand and energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other influential or regulatory issues that may impact the reliability of the BPS.

Over the next 10 years, the electric industry will face a number of significant emerging reliability issues, which are explained in detail throughout this report. Emerging reliability challenges will drive a transformational change for the industry that could potentially result in a dramatically different resource mix with reliance on natural gas and renewable generation, a need for enhanced modeling, a new risk and probabilistic framework built to address reliability challenges, and growing critical infrastructure and protection concerns—both physical and cyber.

One of the most significant overarching findings of this report is a rapid change in resource mix in several areas across North America. While the key factors driving this evolutionary change vary by region, fuel price economics, environmental regulations, and renewable requirements are the most significant factors affecting the pace of change. Fundamentally, substantial modifications to the bulk power system require a great deal of time to design, site, permit, and ultimately construct. As projected in this report, a majority of new generation, as well as older generation expected to retire, will contribute to a significant resource shift. As resources change both in system characteristics and geography, the transmission system will be challenged to develop a more robust grid that is not only resilient to resource shifts, but also other more extreme conditions.

With the exception of the challenges identified in Electric Reliability Council of Texas (ERCOT), the electricity industry has prepared plans for the 2013-2022 assessment period in an effort to provide reliable electric service across North America. As identified in previous assessments, capacity resources in ERCOT have drifted to a level below reliability targets. In other assessment areas, potential impacts of issues that are not yet fully understood could affect the implementation of current plans.

While the highlights of this report are presented independently, they are cross-cutting, and interdependencies between many of these issues present unique challenges to the electricity industry. Growth in flexible resources, such as demand response and quick-start natural gas power generators, and increased transmission plans to integrate renewable resources distant from load centers are encouraging trends. However, fundamental changes to planning and operating strategies must consider evolving risks such as increased dependency on natural gas, uncertainties of variable and renewable generation, and new vectors of penetration for emerging cyber and physical security threats. The confluence of these risks are critically interdependent and must be strategically managed, monitored, and mitigated in order to preserve the reliability of the BPS.

2012 Key Reliability Findings:

Significant Fossil-Fired Generator Retirements Over Next Five Years

Due largely to the unique confluence of final and potential environmental regulations, low natural gas prices, and other economic factors, about 71 GW of fossil-fired generation is projected to retire by 2022, with over 90 percent retiring by 2017. With the exception of ERCOT, the retirement of this capacity does not pose significant resource adequacy concerns. Reserve Margins are likely to be reduced, but to levels that are still above targets. However, retirements over the next three to four years may raise issues related to system stability and the need for transmission enhancements, which if not addressed could cause reliability concerns in some areas.

Increased Risk of Capacity Deficiencies in ERCOT as Planning Reserve Margins Projected to Fall Below Targets

Starting as early as next year, the Electric Reliability Council of Texas (ERCOT) Planning Reserve Margin is anticipated to be 13.4 percent, which is below the NERC Reference Margin Level and ERCOT planning target of 13.75 percent. At these levels, the risk of insufficient generation resources to meet peak demand increases beyond reliability targets.

Resources Sufficient to Meet Reliability Targets in Most Areas

For the majority of the bulk power system, Planning Reserve Margins appear sufficient to maintain reliability through the long-term horizon. However, there are significant challenges facing the electric industry that may shift industry projections adding considerable uncertainty to the long term assessment. Future uncertainties include electricity market changes, fuel-prices (natural gas in particular), potential environmental regulations, and renewable portfolio standards.

Increased Dependence on Natural Gas for Electricity Generation

Increased dependence on natural gas for electricity in some areas has increased the need for all gas users, electric system planners and operators, and policy makers to focus more sharply on the interaction between the electric and gas industries. The adoption of highly efficient combined-cycle technology by the electric power industry and the emergence of shale gas have altered the relative economics of gas-fired generation. As a result, the dependence on natural gas by the electric power sector has increased significantly. Trends in fuel-mix changes highlighted in this assessment identify gas-fired generation as the primary choice for new capacity with almost 100 GW of Planned and Conceptual capacity expected over the next 10 years, which represents almost half of all new generation capacity.

Long-Term Generator Maintenance Outages for Environmental Retrofits

A significant generation retrofit effort is expected over the next 10 years in order to comply with federal and state-level environmental regulations. A majority of environmental controls are expected to be put in place to meet air regulations by April 2016. In total, 339 unit-level retrofits on fossil-fired generation will be needed, totaling about 160 GW. However, there is still significant uncertainty in the forecasted values as maintenance schedules have not yet been fully evaluated by all areas.

Renewable Resource Additions Introduce New Planning and Operational Challenges

Renewable resources are growing in importance in many areas of North America as the number of new facilities continues to increase. The share of capacity from renewable resources will continue to grow, especially as significant additions are projected for both wind and solar throughout North America. In 2012, renewable generation, including hydro, made up 15.6 percent of all on-peak capacity resources and is expected to reach almost 17 percent in 2022. Contributing to this growth is approximately 20 GW of on-peak Future-Planned capacity and an additional 21.5 GW of on-peak Conceptual capacity. It is vital that these variable resources are integrated reliably and in a way that supports the continued performance of the BPS and addresses both planning and operational challenges.

Transmission Growth to Accommodate New and Distant Resources

As recent as five years ago, transmission was being constructed at a rate of about 1,000 circuit miles per year. In the last five years, over 2,300 circuit miles were constructed per year, more than doubling actual builds in the previous five years. With the current plans in place, that rate is expected to increase to 3,600 miles per year over the next five years. NERC-wide, almost a quarter of new transmission is specifically linked to the integration of renewable generation.

Increases in Demand-Side Management Help Offset Future Resource Needs

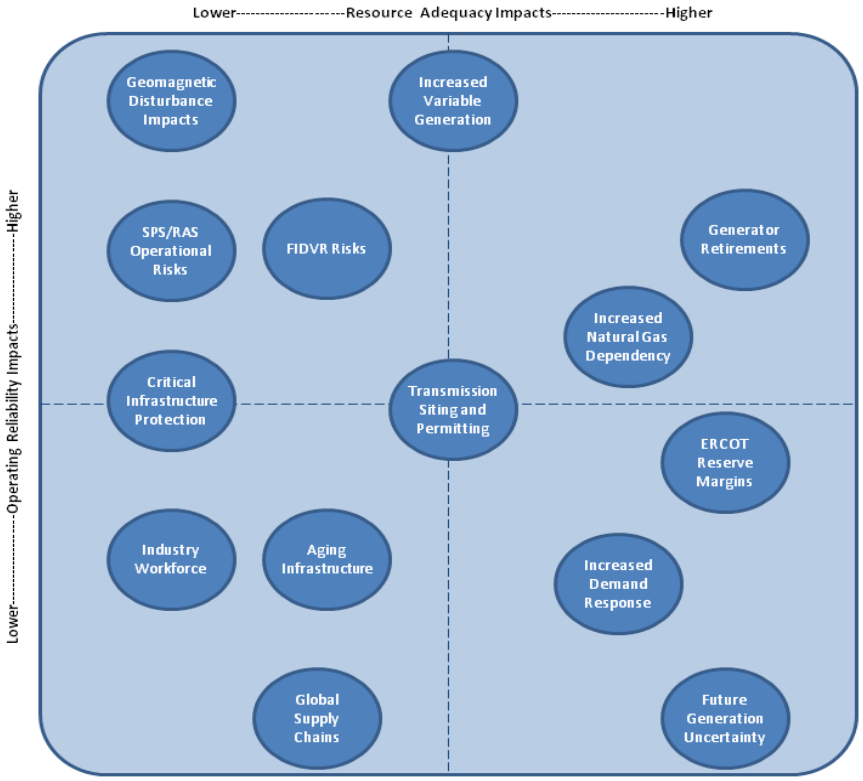
All areas are projecting at least some increased availability of Demand-Side Management (DSM) over the next 10 years to reduce peak demands, contributing either to the deferral of new generating capacity or improving operator flexibility in day-ahead or real-time time operations. NERC-wide, DSM is projected to total roughly 80,000 MW by 2022 (or about 7 percent of the on-peak resource portfolio), offsetting approximately six years of peak demand growth. However, unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of DSM involve greater forecasting uncertainty—particulary with Demand Response resources.

Future Reliability Challenges and Emerging Issue Risk Types

A comprehensive reliability assessment of the North American BPS requires considerations of emerging issues and future risks to reliability. While NERC is in the process of developing a strategic framework to address and prioritize high-risk issues, it is important to recognize how different risks can be exposed and what the potential impact could be to reliability.

Emerging risks identified in the current and past long-term reliability assessment reports are shown in Figure 1. Two fundamental and measurable characteristics of BPS reliability form the foundation of the concepts described in this document—*resource adequacy* and *operating reliability* (or system security). Each issue in Figure I includes the potential to impact these two characteristics differently; therefore, the impacts to system reliability can be different and must be well understood. The results are the product of combined industry surveys, engineering judgment, and NERC's independent assessment.

Figure 1: Future Reliability Challenges and Emerging Issues as a Function of Resource Adequacy versus Operating Reliability Impacts



By understanding these risks, the electricity industry can be more effective in mitigating adverse impacts. With resource adequacy impacts, the ability of the BPS to supply the aggregate electrical demand and energy requirements is compromised. Operating reliability impacts include all other system disturbances that result in the unplanned or uncontrolled interruption of customer demand, regardless of cause. Impacts that spread over a wide area of the grid are referred to as cascading outages—the uncontrolled successive loss of system elements triggered by an incident at any location.

Going forward, an enhanced framework for developing strategic and tactical recommendations will help NERC and the industry effectively focus resources on the critical issues needed to best improve the reliability of the BPS. The Reliability Issues Steering Committee (RISC) is an advisory committee that reports directly to the NERC Board of Trustees and triages and provides front-end, high-level leadership and accountability for nominated issues of strategic importance to reliability. Ultimately, the recommendations will improve efficiency of NERC Reliability Standards development, engage high-level stakeholder leadership, and promote reliability excellence.[15]

[15] RISC Website: http://www.nerc.com/page.php?cid=1|117|428.

Key Reliability Findings

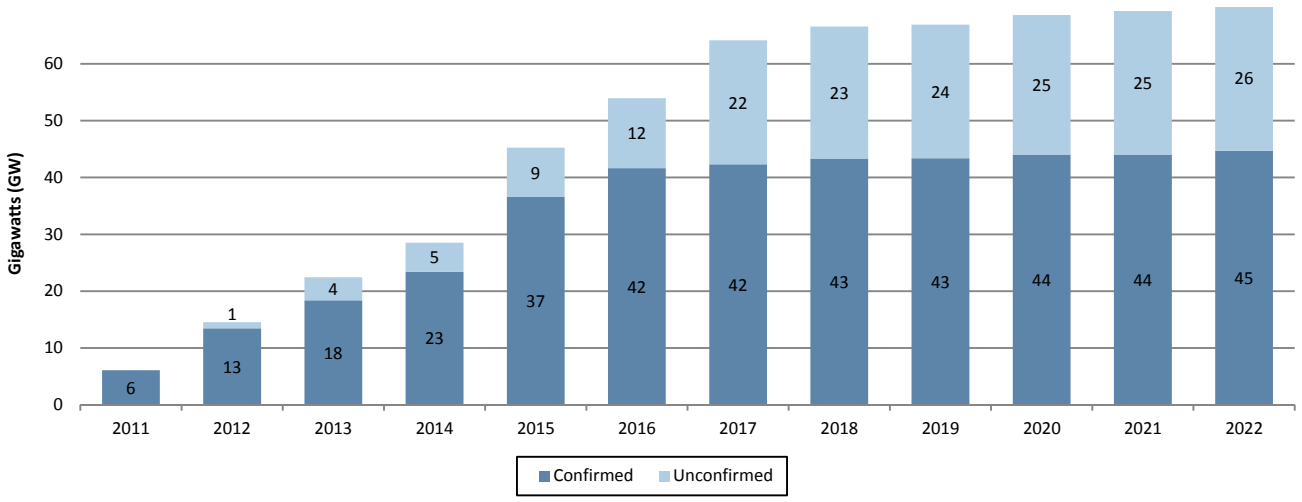
Each year, the Long-Term Reliability Assessment (LTRA) forms the basis for the NERC reference case. This reference case incorporates known policy and regulation changes that are expected to take effect throughout the 10-year timeframe, assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior. This section provides NERC's independent assessment of the 2012 reference case and discusses key findings and challenges of managing reliability concerns.

Significant Fossil-Fired Generator Retirements Over Next Five Years

Largely due to the unique confluence of final and potential federal environmental regulations, low natural gas prices, and other economic factors, approximately 71 GW of fossil-fired generation[16] is projected to retire by 2022, with over 90 percent retiring by 2017. Over the past three years, significant uncertainty surrounding fossil-fired generation retirements has been the most prominent emerging reliability issue assessed by NERC and the electric power industry. For the first time, coal-fired generation is projected to decline over the 10-year assessment period. While significant fossil-fired generation retirements were expected (based on a 2011 NERC assessment), the magnitude of retirements remains uncertain due to generator owners not revealing or announcing plans for unit retirements until recently.

For the *2012LTRA* Reference case, approximately 44 GW of fossil-fired capacity retirements has been confirmed to retire in the next 10 years (Figure 2). Confirmed retirements are those that have been announced or otherwise included in a given Planning Coordinator's resource plans. Additionally, unconfirmed retirement projections have been reported, reaching a total of 26 GW by 2022, a majority of which are projected to retire by 2017 (Figure 3). Projected retirements were forecast by individual assessment areas based on reasonable expectations. For many assessment areas, existing studies and analyses were applied as a basis for retirement projections over and above the amount that has already been confirmed. Some assessment areas did not fully project additional retirements beyond confirmed amounts included in the reference case as insufficient information was available to make a determination.[17] For assessment areas that did not submit supplemental retirement data, the *2012LTRA* Reference case data was applied. Uncertainties still exist and more generators may retire than what is projected in this assessment.

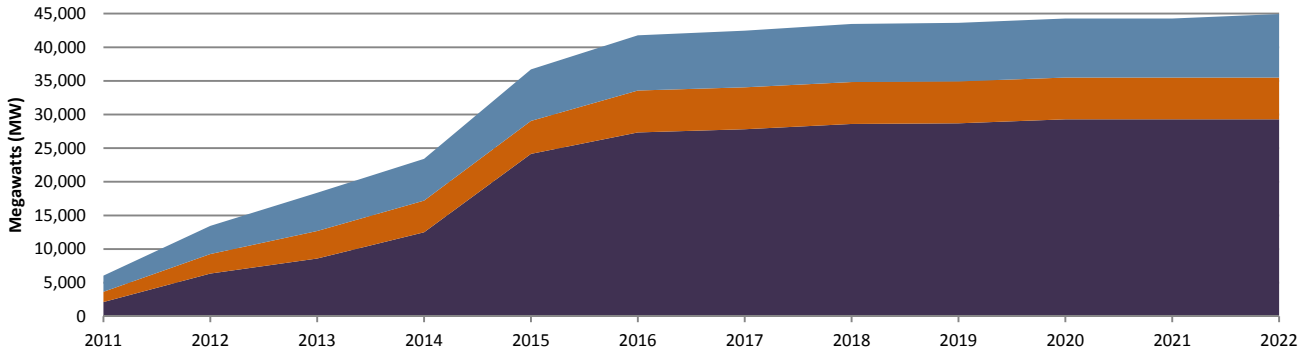
Figure 2: NERC-Wide Cumulative Summer Fossil-Fired Capacity Resource Retirements



[16] NERC reviews the impacts of both controlled and variable resources in this assessment. Variable resources differ from conventional controllable resources, such as fossil-fired resources in a fundamental way: their fuel source (wind, sunlight, andmoving water) cannot presently be controlled or stored. Unlike coal or natural gas, which can be extracted from the earth, delivered to plants thousands of miles away, and stockpiled for use when needed, variable fuels must be used when and where they are available.

[17] ERCOT, FRCC, NPCC-New England, NPCC-Ontario, and SERC Assessment Areas

Figure 3: NERC-Wide Confirmed Retirements by Fuel Type (Summer Capacity)



Capacity Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Coal	2,131	6,380	8,597	12,496	23,615	26,719	27,198	27,971	28,067	28,650	28,650	28,650
Petroleum	1,531	2,880	4,088	4,719	4,909	6,221	6,221	6,221	6,221	6,221	6,221	6,221
Gas	2,405	4,195	5,565	6,086	7,530	7,919	8,121	8,365	8,417	8,493	8,493	8,611
Total	**6,067**	**13,454**	**18,250**	**23,301**	**36,054**	**40,858**	**41,539**	**42,556**	**42,705**	**43,364**	**43,364**	**43,482**

In the *2011 Long-Term Reliability Assessment*, NERC projected capacity losses due to retirements and derates associated with environmental control impacts to generator ratings.[18] Based on the results of the Moderate Case, 36 GW of incremental capacity in coal, oil, and gas-fired generation was identified for either retirement or for capacity reductions to support additional station loads (deratings) by 2018. In the Strict Case, capacity reductions amount to approximately 59 GW. For retirements only, the study indicated a range of 7 GW to 18 GW for 2015 and 32 GW to 54 GW for 2018 (Moderate to Strict Cases represent the ranges).[19] Confirmed and unconfirmed retirements in the *2012LTRA* Refernce case show significantly more generators retiring than had previously been projected by NERC for 2015; however, 2018 projections are more in line with last year's study. This is believed to be due largely to a decrease in natural gas prices as well as the extended compliance period associated with the EPA Mercury and Air Toxics Standard (MATS).[20,21]

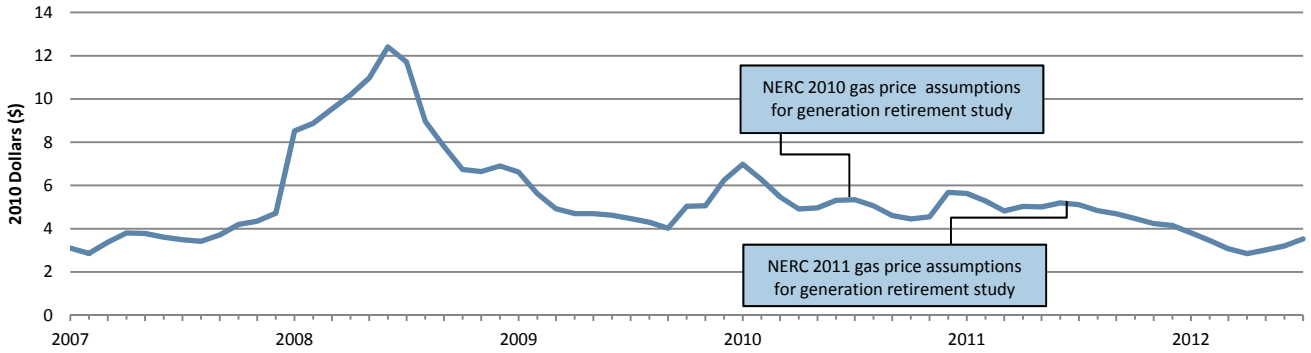
On December 16, 2011, the Environmental Protection Agency (EPA) issued a rule to reduce emissions of toxic air pollutants from power plants. Specifically, MATS will reduce emissions from existing and planned coal- and oil-fired generators by requiring the installation of environmental controls. These controls typically involve the addition of dry sorbent injection[22] or a scrubber on units to control emission levels. Generation owners will ultimately be charged with deciding between investing in the plant to ensure compliance, or closing it permenantly.

Adding to the regulatory constraint, low natural gas in recent years offers incentives for plant owners to convert existing plants from coal to gas. Retirement decisions for existing coal- and oil-fired units are often highly sensitive to the replacement costs for that capacity—which, in effect is fuel cost dependent. Therefore, the option of converting these existing units to natural gas becomes a more economically attractive alternative as gas prices decline. According to the 2011 NERC study on potential generator retirements, a $2 downward swing on natural gas prices could potentially double the amount of retired coal-fired generation as part of the NERC scenario analysis.[23] Henry Hub natural gas prices have dropped

[18] Extraction from *2011 Long-Term Reliability Assessment*: http://www.nerc.com/files/EPA%20Section.pdf.
[19] Derates associated with generator retrofits are embedded within the 2012 LTRA reference case for projected capacity resources and generator ratings and have been considered as part of the overall assessment.
[20] http://www.epa.gov/mats/.
[21] National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, http://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf.
[22] http://www.eia.gov/todayinenergy/detail.cfm?id=5430.
[23] Based on Henry Hub Prices, *2011 Long-Term Reliability Assessment*, Table 35: Projected 2018 Coal Retirements Based on Gas-Price Sensitivity: http://www.nerc.com/files/2011%20LTRA_Final.pdf.

almost $2 since NERC's 2011 study on generation retirements, providing obvious incentives and greater economic benefits to switch from coal or oil to gas generation (Figure 4).

Figure 4: Monthly Average Electric Generation Natural Gas Prices 2007–July 2012 (2010 dollars per million Btu)[24]

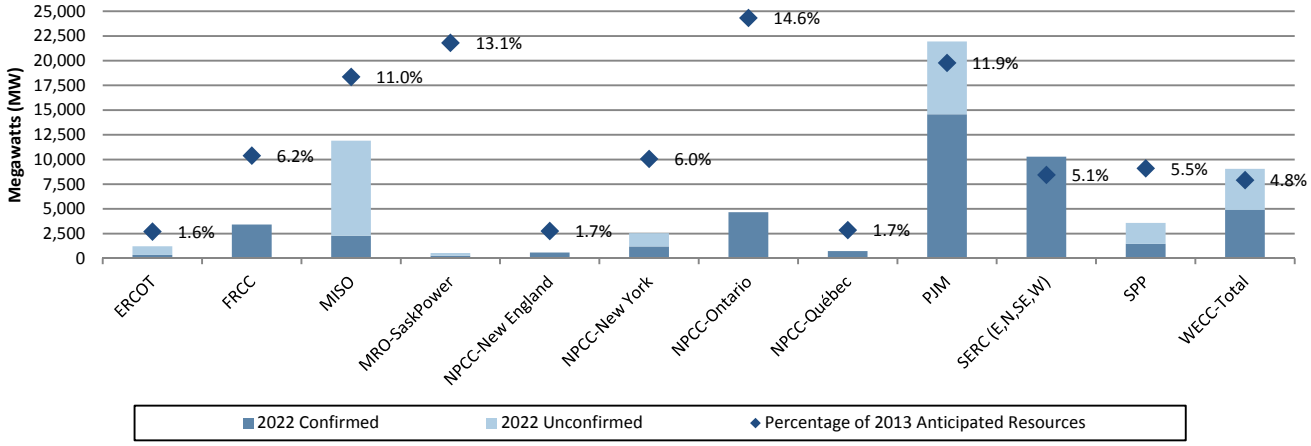


Other reasons for generation retirements include economic-related decisions for continuing the operation of a given plant. Decisions may be impacted by the plant's age, past investment in environmental controls, and other regional-specific issues such as fuel mix, renewable portfolio standards, and impacts of other proposed environmental regulations.

While facility retirements are expected NERC-wide—including in the United States and Canada—some assessment areas will be impacted more than others will. It is important to note that absolute retirement impacts will only cause a resource adequacy concern if retirements cause the Planning Reserve Margin to fall below the targets.[25] For example, PJM is projected to retire the largest amount of fossil-fired capacity by 2022; however, even with 15 GW of generator retirements confirmed, Planning Reserve Margins do not fall below the NERC Reference Margin Level until 2020. The plans for new generation in PJM, along with available reserves, allow PJM the flexibility required to maintain resource adequacy through the long term.

PJM, MISO, and the SERC Assessment Areas are projecting the highest amount of retirements (over 10 GW), as well as the highest percentage relative to total capacity resources—11.9 percent, 11 percent, and 5.1 percent, respectively (Figure 5). Ontario is also projected to retire 14.2 percent of its total capacity by 2014 (Table 1).

Figure 5: NERC-Wide Confirmed and Projected Fossil-Fired Capacity Retirements for 10-Year Period



[24] U.S. Department of Energy – Energy Information Administration: http://www.eia.gov/dnav/ng/hist/n3045us3m.htm.

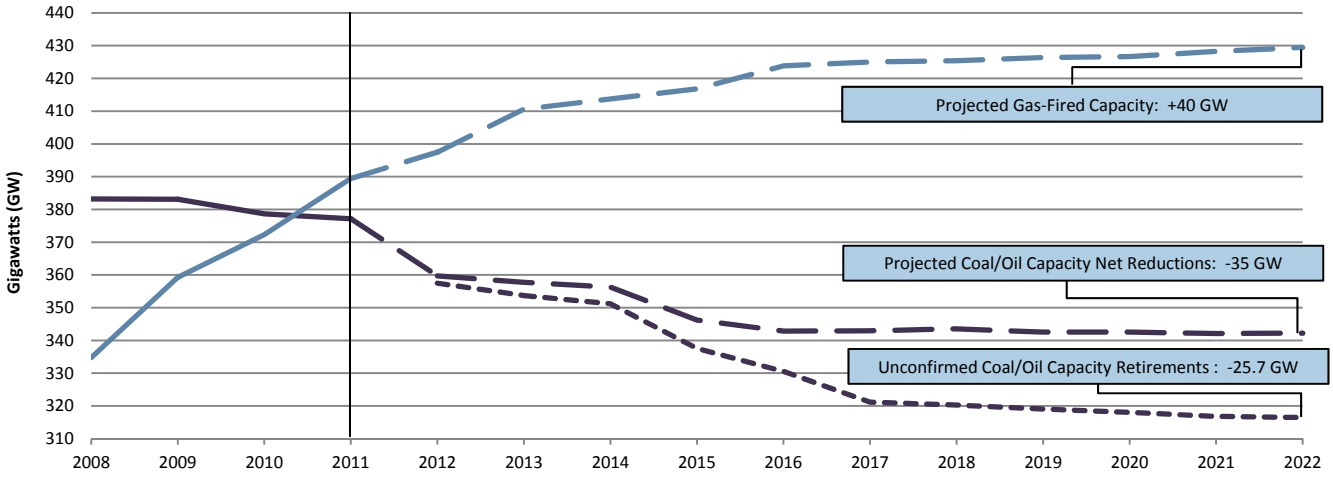
[25] Targets are based on resource planning analysis or regulatory criteria within Regions, NERC Assessment Areas, or Canadian provinces. In some cases, these targets are mandatory. The target for each assessment area is applied as the NERC Reference Margin Level.

Table 1: Cumulative NERC-Wide Confirmed and Unconfirmed Fossil-Fired Capacity Retirements[26]

Assessment Area	Certainty	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ERCOT	Confirmed	342	342	342	342	342	342	342	342	342	342	342	342
	Unconfirmed	-	0	0	0	0	0	0	871	871	871	871	871
FRCC	Confirmed	957	1,344	2,599	2,599	2,611	3,321	3,345	3,345	3,345	3,421	3,421	3,421
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
MISO	Confirmed	1,012	2,170	2,281	2,281	2,281	2,281	2,281	2,281	2,281	2,281	2,281	2,281
	Unconfirmed	-	252	364	364	364	364	9,626	9,626	9,626	9,626	9,626	9,626
MRO-SaskPower	Confirmed	0	0	201	201	262	262	262	262	262	262	262	262
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	278	278
NPCC-New England	Confirmed	0	0	0	587	587	587	587	587	587	587	587	587
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
NPCC-New York	Confirmed	219	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204
	Unconfirmed	-	0	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342
NPCC-Ontario	Confirmed	920	920	920	2,699	4,002	4,112	4,290	4,494	4,546	4,546	4,546	4,664
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
NPCC-Québec	Confirmed	450	730	730	730	730	730	730	730	730	730	730	730
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
PJM	Confirmed	0	1,367	1,601	3,518	12,215	14,578	14,578	14,578	14,578	14,578	14,578	14,578
	Unconfirmed	-	0	1,038	1,931	4,289	7,373	7,373	7,373	7,373	7,373	7,373	7,373
SERC (E,N,SE,W)	Confirmed	977	3,401	4,882	5,605	7,550	9,172	9,467	10,280	10,280	10,280	10,280	10,280
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
SPP	Confirmed	0	0	130	130	676	926	926	926	926	926	926	1,457
	Unconfirmed	-	496	700	737	1,305	1,851	2,108	2,108	2,108	2,116	2,116	2,116
WECC-Total	Confirmed	1,190	1,972	3,485	3,530	4,132	4,132	4,316	4,316	4,316	4,899	4,899	4,899
	Unconfirmed	-	340	613	722	1,366	1,366	1,366	1,911	2,204	3,213	3,655	4,150
TOTAL-NERC	**Confirmed**	**6,067**	**13,450**	**18,375**	**23,426**	**36,592**	**41,647**	**42,328**	**43,345**	**43,397**	**44,056**	**44,056**	**44,705**
TOTAL-NERC	**Unconfirmed**	**-**	**1,088**	**4,057**	**5,096**	**8,666**	**12,296**	**21,815**	**23,231**	**23,524**	**24,541**	**25,261**	**25,756**
TOTAL-NERC	**TOTAL**	**6,067**	**14,538**	**22,432**	**28,521**	**45,259**	**53,943**	**64,143**	**66,576**	**66,921**	**68,597**	**69,316**	**70,460**

For all these reasons, NERC is projecting approximately 64.1 GW of capacity to be retired by 2017 and 70.5 GW by 2022. With the exception of ERCOT, the retirement of this capacity does not pose significant resource adequacy concerns. Rather, issues related to supporting system stability and transmission enhancements required as a result of retiring generation are likely to cause some reliability concerns in areas that are impacted by large generator retirements (Figure 6).

Figure 6: NERC-Wide Confirmed and Projected Fossil-Fired Capacity Retirements (with 2011 as a base-year)[27]



[26] Net On-Peak summer capacity.

[27] Natural gas and coal/oil projections projections are aggregated from *2012 LTRA* reference case data and represent net changes (i.e., there are increases in capacity throughout the assessment period as well). Capacity changes are due to a combination of capacity retirements, derates, and maintenance outages. Unconfirmed retirements of oil and coal were provided through a supplemental data request. Details on this request are provided in Appendix IX. The *2012LTRA* Reference case indicates approximately 32 GW of gas-fired capacity is projected from 2012-2022. This figure has a base-year of 2011, with over 40 GW projected from 2011-2022.

The retirement of larger and/or strategically situated generating units will cause changes to the power flows and the performance of the bulk power system. These changing characteristics will require enhancements to the interconnected transmission systems to provide reactive and voltage support, address thermal constraints, and provide for system stability.

System planners and operators must understand and study impacts of every generator that may be retired; in market areas, this analysis is performed with a retirement request of the market participant. Federal environmental rule compliance deadlines will challenge the electric industry's planning horizons and processes. Transmission lines and facilities, as well as power plants, are often planned and constructed over a long period of time. Therefore, sufficient time is needed so that plans can be developed and implemented to accommodate generator retirements. If these decisions are made in a time frame that does not allow for building new generation capacity or transmission enhancements, overall system reliability could be adversely affected.

The lack of certainty has left system planners with little information on how the system might be changed in the future. For example, in many of the deregulated market areas, the ISO/RTO, performing the Planning Coordinator function, has little insight into the retirement decisions of generators serving the market. Many of the ISO/RTOs have challenges in identifying generators that will retire, because the market rules or criteria do not require generators to inform the system operator until 90 days prior to the requested retirement date or termination of an interconnection agreement. However, those areas with a forward capacity market structure are able to foresee market participant withdrawals up to three years in the future. For example, in PJM, almost 15 GW of existing fossil-fired generation did not bid into the capacity market. While this capacity has not all been officially announced to retire, the PJM planning process, along with this assessment, does not include this generation in future reliability analyses. Areas without this capability or other methods to provide planning coordination with sufficient lead time to determine reliability impacts are left with significant uncertainty as to the amount and timing of retirements.

As a result of generator uncertainties, transmission plans needed to accommodate generator retirements are impacted. System planners' responsibilities include analyzing expected future changes in generation and transmission assets, such as the retirement of a generating unit; customer demand; and emerging reliability issues. For example, once a system planner learns that a power company intends to retire a generating unit, the system planner generally studies the electric system to assess whether the retirement would cause reliability challenges and then identifies solutions to mitigate any impacts. The solutions could be in the form of replacement capacity (generation or demand-side resources), new transmission lines, or other equipment, each with its own associated permitting and construction timelines.

Other compounding issues, such as dependency on gas-fired generation, significant generator retrofit maintenance outages, and an increasing need for system flexibility, will pose continued challenges for planners and operators of the performance of the BPS. As more gas-fired generation is brought on-line in the bulk power system, gas dependency issues must be addressed. Increased gas-fired capacity may require additional gas pipeline infrastructure, increased coordination with pipeline operators, and developing operational strategies to minimize potential fuel delivery issues. These issues were highlighted in a recent NERC report[28] on gas and electric interdependencies and are also highlighted later in this report.

When a Planning Coordinator receives a deactivation request from a Generator Owner, it simulates power flows and stability of the bulk power system and assesses resource adequacy based on forecast system conditions. Detailed modeling studies analyze system configurations against NERC and Regional Reliability Standards to identify transmission overloads, voltage limitations, system stability, and other reliability performance conditions. The Planning Coordinator is required to develop plans and implement solutions for each potential violation, which could otherwise lead to overloads, equipment failure, instability, and, in the most extreme circumstances, uncontrolled, widespread cascading outages.

[28] 2011 NERC Special Assessment Report: A Primer of the Natural Gas and Electric Power Interdependency in the United States: http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf

Based on information gathered from stakeholders and the Regional Entities, a large amount of retirements occurring over a short period may cause reliability concerns. In some cases, these reliability issues could result in violations of NERC Reliability Standards and, therefore, pose a threat to reliability if not addressed. System impact studies, conducted by Planning Coordinators, will be able to identify impacts and potential mitigation strategies to address the announced and planned retirement of facilities.

Overall, generation retirements need to be evaluated and analyzed in an integrated fashion. While the high degree of uncertainty surrounding retirement decisions continues to be exceedingly difficult, power system planners must continue not only to study the effects of individual generator impacts, but also to recognize the cumulative impacts of multiple generator retirements.

Risk Assessment Summary

Impacted Assessment Area(s)	PJM MISO SERC
Impact Type	Resource Adequacy - Significant generator retirements can cause capacity deficiencies and may affect the power system's ability to meet peak demands.
Magnitude of Impact	Operating Reliability – Local transmission reliability impacts due to large plant retirements
	44 GW of Fossil-Fired Generation Confirmed to Retire
	24 GW of Fossil-Fired Generation Projected to Retire
Likelihood of Impact	Confirmed retirement capacity is very likely to retire based on the current schedule. However, it is possible that these plans change in the future depending on changes in regulations, technologies, and fuel prices.
	Short terms; a majority of the retirements are expected by 2016

Recommendations

NERC	NERC should continue to monitor retirements and emerging reliability issues stemming from significant generator retirements in the *Long-Term Reliability Assessments*.
Generator Owners and Operators	Generator Owners and Operators that are disconnected from wide-area planning functions (e.g., generator owners operating in an ISO/RTO), should provide Planning Coordinators timely and accurate information about the retirement plans for their units in order to adequately assess any reliability concerns. While changes to market rules are not necessarily needed, discussions should occur and expectations should be shared with independent authorities on reliability.
Planning Coordinators	All Planning Coordinators should employ available tools and processes to ensure that BPS reliability is maintained through any resource transition. Regional wholesale competitive market operators should ensure markets are functioning effectively to support the development of new replacement capacity where needed.

Increased Risk of Capacity Deficiencies in ERCOT as Planning Reserve Margins Projected to Fall Below Targets

Starting as early as next year, the Electric Reliability Council of Texas (ERCOT)[29] Planning Reserve Margin is projected to be below the NERC Reference Margin Level. Specifically, for 2013 the Anticipated Reserve Margin of 13.4 percent is below the ERCOT planning target (NERC Reference Margin Level) of 13.75 percent.[30] At these levels, the risk of insufficient generation resources to meet peak demand increases beyond the accepted target. Throughout the 10-year assessment period, the Planning Reserve Margin continues to degrade and is projected to fall below five percent by 2017 and approximately zero by 2020 if more resources are not acquired. By not meeting the Planning Reserve Margin target of 13.75 percent, ERCOT is unable to meet a "one-event-in-ten" planning target.[31] With ERCOT Planning Reserve Margins below the NERC Reference Margin Level, ERCOT does not appear to have sufficient resources during the summer peak to maintain target resource adequacy levels at any point throughout the assessment period (Figure 7 and Table 2).

Figure 7: ERCOT Summer Planning Reserve Margins

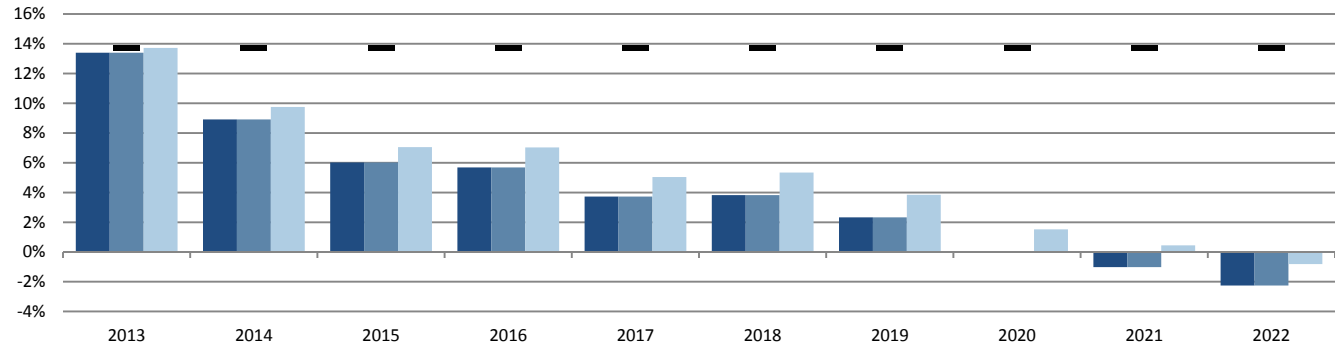


Table 2: ERCOT Planning Reserve Margins

ERCOT-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		13.40%	8.91%	6.02%	5.69%	3.72%	3.82%	2.33%	0.04%	-1.02%	-2.26%
PROSPECTIVE		13.40%	8.91%	6.02%	5.69%	3.72%	3.82%	2.33%	0.04%	-1.02%	-2.26%
ADJUSTED POTENTIAL		13.72%	9.75%	7.06%	7.03%	5.04%	5.34%	3.84%	1.52%	0.44%	-0.82%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

ERCOT-Winter		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		53.03%	52.33%	47.01%	48.32%	40.96%	42.49%	40.71%	39.72%	37.78%	32.35%
PROSPECTIVE		53.03%	52.33%	47.01%	48.32%	40.96%	42.49%	40.71%	39.72%	37.78%	32.35%
ADJUSTED POTENTIAL		55.34%	57.43%	53.33%	56.81%	49.02%	52.00%	50.20%	49.10%	47.03%	41.24%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

The projected capacity deficiencies may result in an increased probability of interruptions of firm load to maintain reliability. Reserve margins are calculated using a 50/50 peak demand forecast.[32] Therefore, these values represent what is considered a normal summer with a normal electric peak demand. However, the onset of extreme and sustained hot temperatures may cause ERCOT to initiate rotating outages to maintain the reliability of the interconnection and prevent uncontrolled, cascading outages. As reserve margins decrease below reliability targets, the probability of rotating outages

[29] The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator for the ERCOT Interconnection and schedules power on an electric grid that connects 40,500 miles of transmission lines and more than 550 generation units. Texas Reliability Entity (TRE) is the Regional Entity responsible for assessing the reliability of the bulk power system within ERCOT.

[30] The ERCOT Planning Target of 13.75 percent is a planning target applied based on a probabilistic analysis performed by ERCOT. See *2010 ERCOT Long Term System Assessment*: http://www.ercot.com/content/news/presentations/2010/ERCOT%202010%20Long%20Term%20System%20Assessment.pdf ERCOT's Planning Target is included as the NERC Reference Margin Level in this assessment.

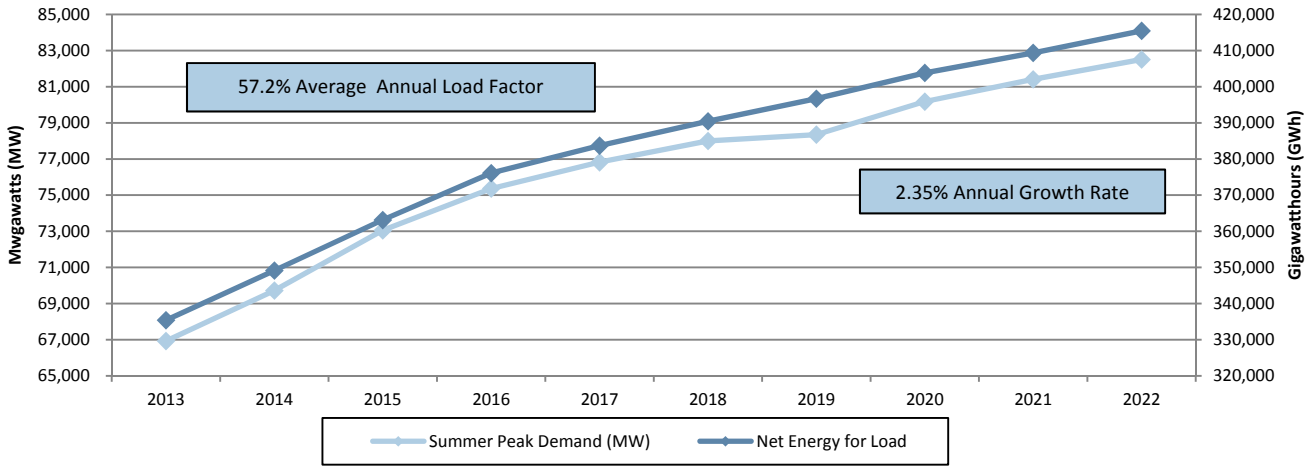
[31] Reliability planning for the bulk power system, or resource adequacy planning, has historically been based strictly on Loss of Load Expectation (LOLE), or the number of firm load shed events an electric system expects over a period of one or more years. The electric power industry has for decades used an LOLE of 1 day of firm load shed in 10 years as the primary, if not sole means for setting target reserve margins and capacity requirements in such resource adequacy analyses. While this is not a regulatory requirement in ERCOT, this planning criteria is the generally accepted industry standard for maintaining sufficient resources to meet peak demands.

[32] Forecasts cannot precisely predict the future. Instead, many forecasts report a baseline or most likely outcome, and a range of possible outcomes based on probabilities around the baseline or midpoint. Actual demand may deviate from the midpoint projections due to variability in key factors that drive electricity use. For these forecasts, there is generally a long-run 50 percent probability that actual demand will be higher than the forecast midpoint and a long-run 50 percent probability that it will be lower.

increases. Meeting resource adequacy targets in ERCOT over the next 10 years will largely be a function of the extent and frequency of extreme and prolonged weather events and whether timely capacity additions can be integrated. Most importantly, current forecasts do not appear to be sufficient to meet a "normal" peak demand forecast.[33]

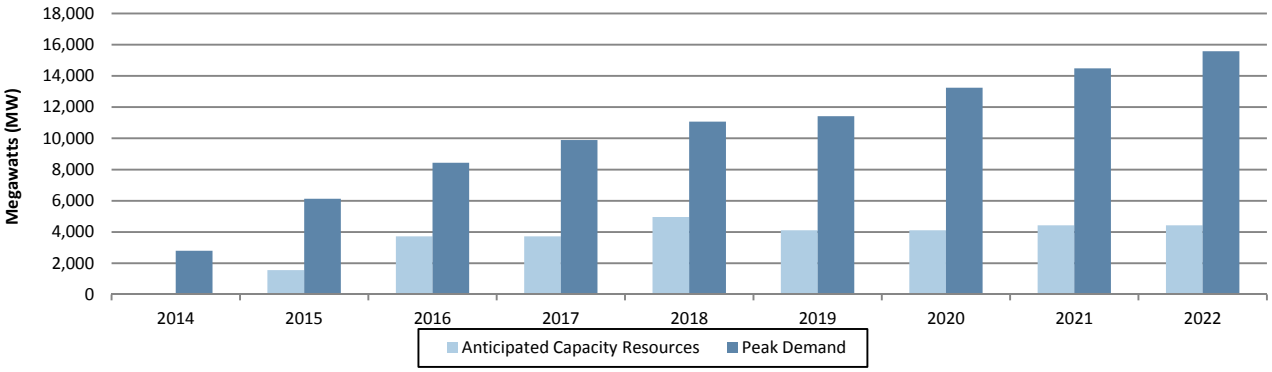
With significant demand growth expected in Texas, even slight deviations from the peak demand forecast can significantly impact the area's flexibility on peak. Over the next 10 years, peak demand in ERCOT is expected to increase by almost 16,000 MW (or 23 percent), which is the largest growth across all NERC assessment areas (Figure 8).

Figure 8: ERCOT – Highest 10-Year Projection for Peak Demand and Energy Growth



The expectation that Planning Reserve Margins will be below the NERC Reference Margin Level is a result of limited knowledge of plans for future generation development and retirements, especially due to uncertainty in ERCOT's marketplace. Uncertainty in the supply of future resources is causing significant reliability concerns as projected resources cannot keep up with the large peak demand growth (Figure 9).

Figure 9: ERCOT – Cumulative Summer Peak Demand Growth Projected to Outpace Supply Resources



It is important to note that resource adequacy and its impact on the Planning Reserve Margin is at the forefront of policy maker discussions in Texas, and there are a number of proposals to incent more generation development as well as other non-traditional resources. The projections for Planning Reserve Margin deficits will vary as solutions are implemented. A project has been created to discuss the options, opinions, and concerns by the Public Utility Commission of Texas (PUCT).[34]

[33] ERCOT Planning – 2012 Long-Term Demand and Energy Forecast http://www.ercot.com/content/news/presentations/2012/2012%20Long-Term%20Hourly%20Peak%20Demand%20and%20Energy%20Forecast.pdf

[34] See Project No. 40000 at the Public Utility Commission of Texas.

Since ERCOT operates within its own interconnection, opportunities to import more power from neighboring areas are limited. The amount of capacity imports considered Firm by ERCOT is just under 600 MW. Assistance from outside entities is restricted to a maximum of approximately 1,100 MW. While there are some transmission projects being considered to increase the transfer capabilities between ERCOT and Eastern and Western Interconnections,[35] these projects are too early in development to be considered for this assessment (Table 3).

Table 3: ERCOT Capacity Transactions (Summer Peak)

ERCOT-Summer	2013	2022
Expected Imports	0	0
Firm Imports	598	598
TOTAL IMPORTS	598	598
Expected Exports	0	0
Firm Exports	317	0
TOTAL EXPORTS	317	0
TOTAL NET CAPACITY TRANSACTIONS	**281**	**598**

Short of building more generation within ERCOT or relying on future transmission projects to increase transfer capabilities, there are additional opportunities to procure more demand-side resources in the future.

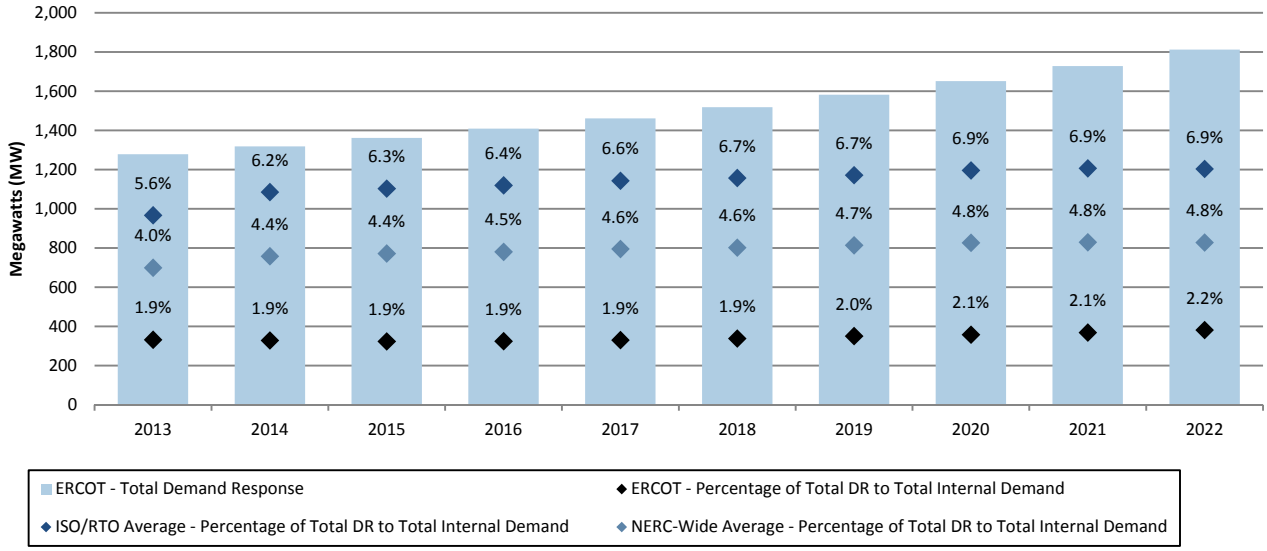
Demand-Side Management (DSM) programs, which include Conservation, Energy Efficiency (EE), and a variety of Demand Response (DR) programs, provide the industry with the ability to reduce peak demand and to potentially defer the need for some future generation capacity. EE concentrates on end-use energy solutions and targets permanent reduction of electricity consumption, attempting to reduce the demand for power. DR works to change the timing of energy use from peak to off-peak periods by transmitting changes in prices, load control signals, or other incentives to end users to reflect existing production and delivery costs.

Currently, ERCOT has almost 1,300 MW of expected dispatchable and controllable demand response available for market operations. Load Resources (LRs)[36,37,] provide Responsive Reserve Service (RRS) and Emergency Response Service (ERS) designed to be deployed in the late stages of a grid emergency prior to shedding involuntary Firm load and represents contractually committed interruptible load.[38,39] Additional demand response exists in ERCOT, but market rules currently limit the amount commercially available. This commercially available amount equates to approximately 2 percent of the forecast Total Internal Demand for the assessment area. This is significantly less than both the NERC-wide average, which is approximately 4 percent, and the ISO/RTO average, which is approximately 5.5 percent and will increase to 7 percent by 2022.

ERCOT also has an almost untapped resource market in the residential sector. Increasing demand response capabilities can provide some significant benefits in the short-term. Since demand response can be "installed" in a relatively short time frame, these resources have the potential to provide ERCOT operators with the flexibility that is needed during peak demand periods in the upcoming years. The increasing amount of smart meters and other smart grid technology in the state of Texas may also provide additional demand-side resources, which will help to partially offset potentially insufficient generation resources (Figure 10).[40]

[35] http://www.tresamigasllc.com/.
[36] Categorized as Load as a Capacity Resource Demand Response in this assessment.
[37] http://www.ercot.com/content/mktinfo/dam/kd/ERCOT Percent20Methodologies Percent20for Percent20Determining Percent20Ancillary Percent20Service Percent20Requir.zip.
[38] The 886 MW represent LR participation in RRS capacity during the peak month of August 2011 across the peak hours (3-6 PM).
[39] See Section 3.14.3 of the current ERCOT protocols:http://www.ercot.com/content/mktrules/nprotocols/current/03-051012_Nodal.doc.
[40] ERCOT Advanced Metering Initiative: http://www.ercot.com/services/projects/current/80027_01/index

Figure 10: ERCOT – Demand Response Mix Less Than Industry Averages



While some enhancements have already been made—such as increasing the scarcity pricing cap—ERCOT, along with the Public Utility Commission of Texas (PUCT), continues to identify and evaluate potential solutions to incentivize new capacity resources. Some of these potential solutions include developing more demand-side management resources with more demand response programs and increasing conservation capabilities, implementing state-mandated resource adequacy targets, and enhancing existing market mechanisms, which may include further increasing scarcity pricing or integrating a capacity component to the market structure.

The ongoing resource adequacy challenges in ERCOT are dynamic. The state regulator (PUCT) continues to be proactive in developing solutions that will be most beneficial to the electric stakeholders across Texas.[41] Most recently, changes in wholesale market rules for ERCOT were adopted in an effort to increase incentives for new capacity investments and to ensure reliability targets can be met.[42]

Ultimately, the resource adequacy concerns in ERCOT are more likely to impact the reliability of the BPS during peak conditions or in an extreme event. Since capacity deficiencies are likely to result in having to implement emergency operating procedures—which may include shedding firm load—uncontrolled cascading of the BPS is unlikely. However, the likelihood of this impact is highly dependent on weather conditions and resulting impacts to peak demand, especially in the summer. If actual peak demand increases beyond the summer forecast, the potential for rotating system outages grows. Prolonged extreme conditions also increase the last several days during the summer peak season.

[41] Resource Adequacy docket at the Public Utility Commission of Texas (Docket No. 40000)
[42] http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.508/25.508.pdf

Risk Assessment Summary

Impacted Assessment Area(s)	ERCOT
Impact Type	Resource Adequacy - Significant generator retirements and lack of new resources can cause capacity deficiencies and may affect the power system's ability to meet peak demands.
Magnitude of Impact	Degrading Reserve Margins: Anticipated Reserve Margin below NERC Reference Margin Level in every year and is zero by 2020 unless more capacity is added
	Rotating System Outages: Capacity deficiencies can trigger emergency operating procedures that may include the shedding of firm load.
Likelihood of Impact	With ERCOT Planning Reserve Margins projected to be below the NERC Reference Margin Level in 2013, the probability of a capacity deficiency is increased and will continue to increase throughout the assessment period unless more capacity is added.

Recommendations

NERC	NERC should continue to assess plans and actions to address resource adequacy issues. Seasonal reliability assessments will provide a better short-term view on the preparations to maintain reliability through the upcoming season.
ERCOT	ERCOT should consider alternative solutions to resource adequacy issues and provide a strategic plan outlining the measures it is taking to increase reserve margins and ensure reliability.
	ERCOT should continue to provide information to the PUCT for continued development of policies in support of a solution to incease capacity resources.
Regulators	NERC strongly recommends that the PUCT and ERCOT identify and implement near-term and long-term solutions to decrease the likelihood of a capacity deficiency. While there has been a significant amount of work done at the PUCT on addressing this issue,[43] there has been little progress on bringing new resources online.

[43] Texas Public Utility Commission Proceeding to Ensure Resource Adequacy in Texas, http://www.puc.texas.gov/industry/projects/electric/40000/40000.aspx

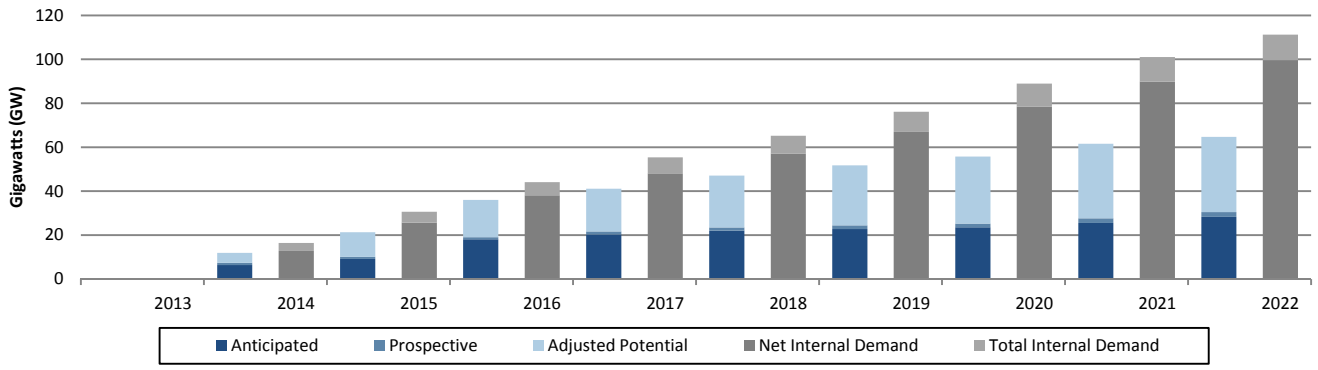
Resources Sufficient to Meet Reliability Targets in Most Areas

NERC assesses resource adequacy by evaluating each Assessment Area's Planning Reserve Margins—a deterministic method based on traditional capacity planning.[44] For the majority of the bulk power system, Planning Reserve Margins appear sufficient to maintain reliability during the long-term horizon. However, there are significant challenges facing the electric industry that may shift industry projections and cause the NERC reference case to change, adding considerable uncertainty not only in the long term, but in the short term as well. Where markets exist, signals for new capacity must be effective for planning purposes, which can impact necessary lead times to construct new generation, as well as any associated transmission. A transition to reduce environmental impacts through policy, specifically through regulatory compliance deadlines, could ultimately conflict with existing planning and approval processes—both regional and interregional.

Supply and Planning Reserve Margin projections in this assessment do not necessarily take into account all retirements of generators due to all potential environmental regulations and other industry risks. While some generators have already announced and planned for retirement, the majority of vulnerable generation resources have not finalized plans. A significant amount of generation retirements can have a considerable impact on Planning Reserve Margins if new resources and associated transmission cannot be constructed or acquired before the compliance deadlines. The results would drive on-peak Planning Reserve Margins lower than forecasted in this assessment. The uncertainty inherent in future generation retirements is representative of the future supply forecast as well. Without a firm understanding of future generation retirements, plans for replacement capacity are left uncertain (Figure 11).

Long-term uncertainty can increase due to the growth in demand response, as well as shorter lead times for bringing on-line natural gas and renewable generation capacity. All of these drivers contribute to future uncertainty as system planners can defer large capacity development projects for longer periods of time, allowing decisions to be made at a later time without an impact to reliability.

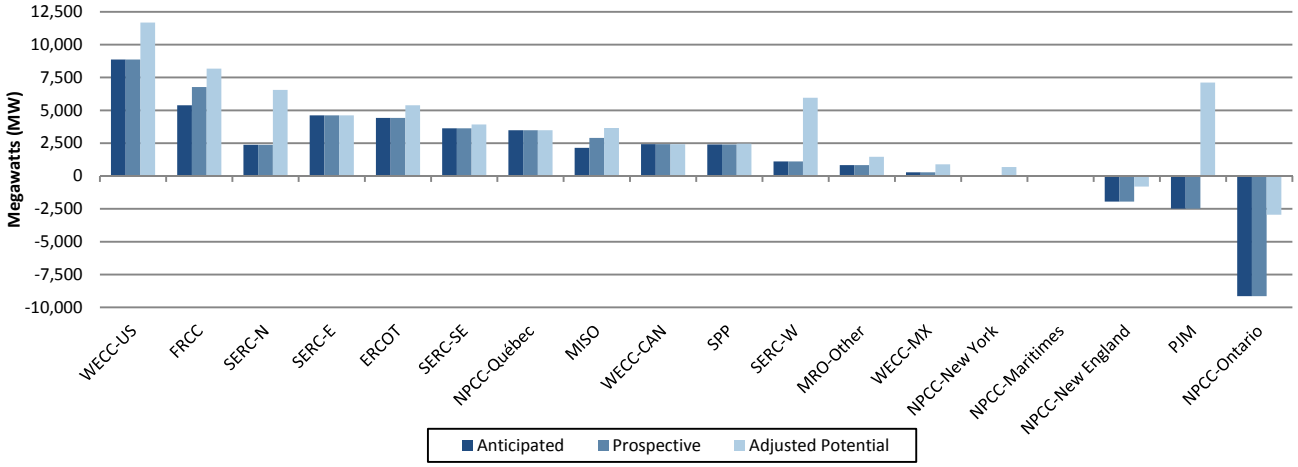
Figure 11: Net Cumulative Change in Supply and Demand Forecasts; Supply Categories Show Different Degrees of Resource Uncertainty; Demand Growth Outpaces Supply



However, the long lead times for developing and constructing transmission are difficult to align with the shorter lead times for resources. Although generating plant in-service lead times have been significantly reduced (excluding environmental permitting processes), transmission planning and approval necessary to integrate these new resources have not experienced a similar lead-time reduction (Figure 12).

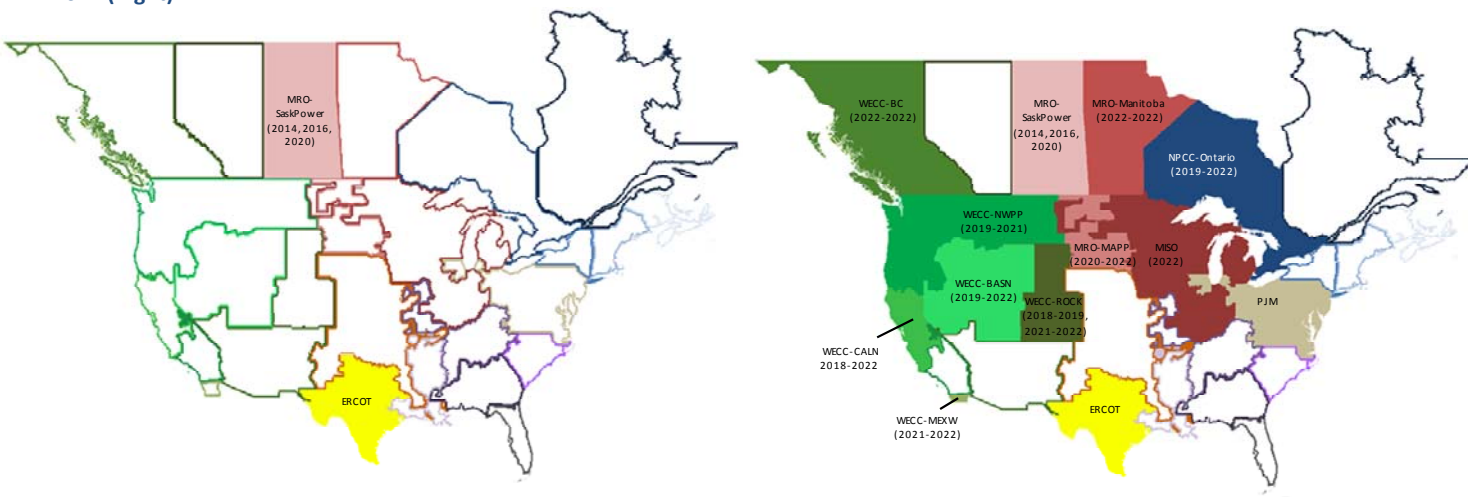
[44] Planning Reserve Margins in this report represent margins calculated for planning purposes (Planning Reserve Margins) not operational reserve margins that reflect real-time operating conditions. See *Estimated Demand, Resources, and Reserve Margins* for specific values.

Figure 12: Future Net 10-Year Capacity Change by Assessment Area



As mentioned earlier in this report, Planning Reserve Margins in ERCOT are projected to significantly decline over the assessment period. Additionally, the approximately 5,000 MW of projected resources does not appear to be sufficient to keep pace with peak demand growth. A considerable amount of Conceptual resources (which are included only as Adjusted Potential Resources), appears to be the primary reason that Ontario, PJM, and the WECC assessment areas fall below the NERC Reference Margin Level (Figure 13).

Figure 13: Assessment Areas with Anticipated Reserve Margins that fall below the NERC Reference Margin Level by 2014[45] (Left) and 2022 (Right)[46]



In general, long-term planning (beyond five years) is inherently uncertain due to, among other things, varying market practices and regulatory conditions, such as environmental regulations. In the areas where Anticipated Resources fall short of meeting the NERC Reference Margin Level, Adjusted Potential Resources must be accelerated, if necessary. However, Adjusted Potential Resources carry a higher degree of uncertainty because these resources are in the early stages of

[45] When evaluating system requirements for new generation, SaskPower utilizes a mostlikely load forecast accounting for load risk to project demand requirements. This is not based on a 50/50 probability. For the purpose of this study, utilization of a less conservative 50/50 load forecast probability would result in higher reserve margins ranging from approximately 16 to 23 percent. Furthermore, for the purpose of this assessment, the NERC Reference Margin Level is 11 percent (lower end of probabilistic EUE range) throughout the assessment period. Saskatchewan has planned for adequate resources to meet anticipated load throughout the assessment period.

[46] Assessment Areas with no dates in parenthesis maintain Anticipated Reserve Margins that are above the NERC Reference Margin Level throughout the assessment period.

development. Therefore, considerable progress in resource development must be made in order to bring these resources online. Engineering studies, siting and permitting, and construction represent the activities required before these resources can have reasonable expectation of going into service. Should peak demand grow faster than projected, additional Conceptual resources should be developed, as they likely will be needed to maintain resource adequacy.

Risk Assessment Summary

Impacted Assessment Area(s)	ERCOT
	MISO
	MRO
	NPCC-Ontario
	PJM
	WECC
Impact Type	Resource Adequacy - Lower than anticipated capacity additions can contribute to a capacity shortage
Magnitude of Impact	With the exception of ERCOT, all other impacted areas have at least five years to enhance plans to ensure sufficient resources are constructed or procured.
Likelihood of Impact	The likelihood of an event that impacts reliability is greatly reduced if proper planning processes sufficiently reflect resource uncertainties
	Conceptual resources are generally in early planning stages and have a high degree of uncertainty associated with project completion

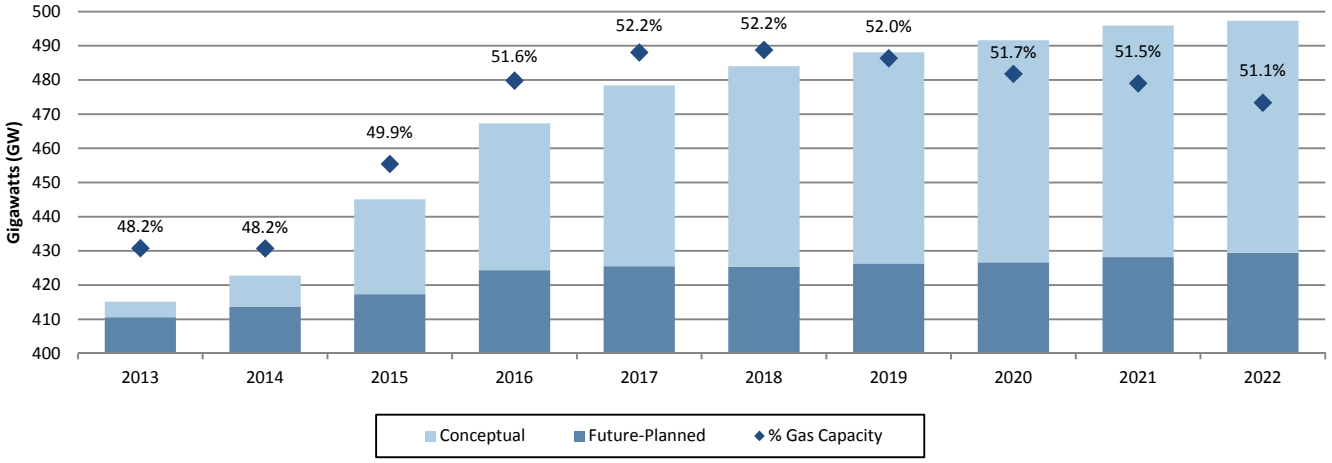
Recommendations

NERC	NERC should consider evaluating generator uncertainties using a probabilistic risk basis, rather than a deterministic approach in its reliability assessment.

Increased Dependence on Natural Gas for Electricity Generation

The growth in natural gas demand within the electric sector has important implications on other gas-consuming sectors, such as commercial and residential heating or industrial manufacturing. Increased dependence on natural gas in the electric sector has increased the need for all gas consumers, electric system planners and operators, and policy makers to focus more sharply on the interaction between the electric and gas industries. For a variety of reasons, including the adoption of highly efficient combined-cycle technology by the electric power industry and the emergence of shale gas, both of which have altered the relative economics of gas-fired generation, the dependence on natural gas by the electric power sector has increased significantly. Trends in fuel-mix changes highlighted in this assessment identify gas-fired generation as the premier choice for new capacity with almost 100 GW expected over the next 10 years, which represents almost half of all new generation capacity (Figure 14).

Figure 14: NERC-Wide Future Gas-Fired Capacity Serves Over Half the Projected Peak Total Internal Demand by 2016



Increasing gas-fired generation to meet electric loads in the future does not come without dependency risks. Increased dependence on natural gas can amplify the bulk power system's exposure to disruptions of fuel supply, transportation, and delivery. In order to accommodate a significant amount of gas-fired generation, BPS planners must understand the different functions gas-fired generation will perform (i.e., baseload and midrange support versus load following and peaking support). Risks to reliability must also be addressed through the three primary timeframes of system planning and operations: Long and Short-Term Planning (1–10 years), Operational Planning (1 day–1 year), and Operations (1 day–real-time) (Table 4).

Table 4: Reliability Considerations for Accommodating Large Amounts of Gas-Fired Generation

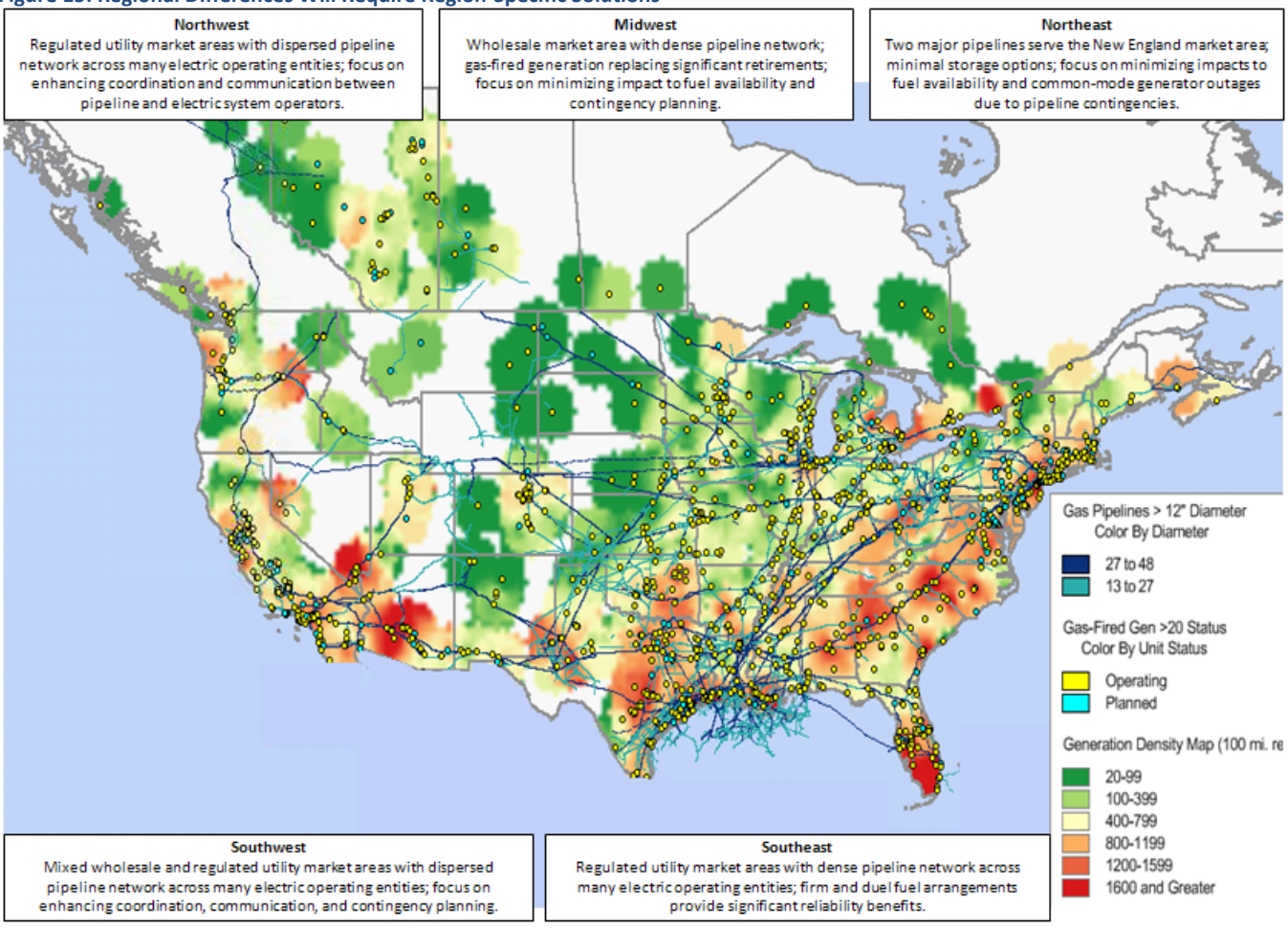
Long- and Short- Term Planning	Operational Planning	Operations
Gas supply and fuel security	Seasonal and day-ahead observability	Information sharing and visibility
Dual-fuel capabilities	Coordinated operational procedures	Communication and information exchange
Fuel transportation expectations	Coordinated outage schedules	Emergency operating procedures
Generator availability	Increasing flexibility	
Resource planning		
Reliability assessment and resource adequacy studies		

NERC's Phase II effort on gas dependency targets these very issues. The report focuses on the different risks that can affect BPS reliability, identifying practices that minimize vulnerabilities, and identifying approaches where coordinated inter-industry efforts could provide enhanced system reliability.

A key area of focus is the need for increased coordination between the two industries, particularly at a regional level. It is important to understand the fundamental differences between how the two industries plan for the long term, communicate with each respective stakeholder, and operate within different regulatory frameworks. While solutions to mitigate increasing risks will be vast and Region-specific, NERC should ensure that enhancements to planning processes will

account for expected uncertainty in gas-fired generation performance as well as potential contingencies on the pipeline network. Furthermore, operational procedures should include a certain level of formalized coordination with the gas pipeline industry, with specific attention on emergency operating procedures during extreme events. Each Region will have unique issues to resolve; therefore, efforts to reduce these risks will vary. These new challenges include a reduction of fuel supply diversification within the power industry, incorporating risks into planning processes and operational procedures, and the need to adapt fuel procurement, transportation, and storage strategies (Figure 15).

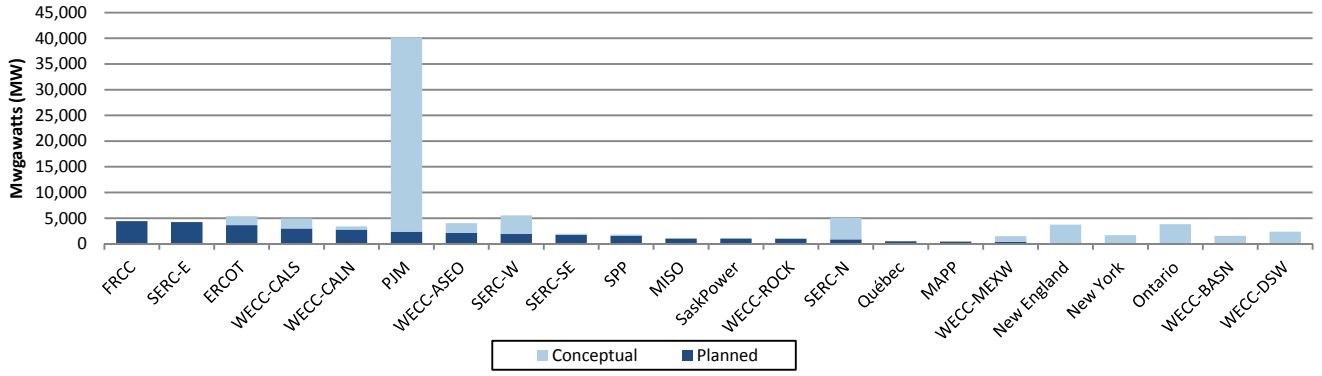
Figure 15: Regional Differences Will Require Region-Specific Solutions[47]



The amount of gas-fired capacity additions also contributes to the regional differences and vulnerabilities that could impact BPS reliability in the future. With natural gas as the premier fuel for new generation, gas-fired capacity additions are largely a function of forecasted peak demand increases and the amount of coal and oil-fired generation within a given assessment area. With significant generator retirements expected in the forecast, PJM is projecting approximately 40,000 MW of new gas-fired generation; however, over 37,000 MW are Conceptual and still in the early planning stages (Figure 16). No more than 5,000 MW are either Planned or Conceptual in all other areas.

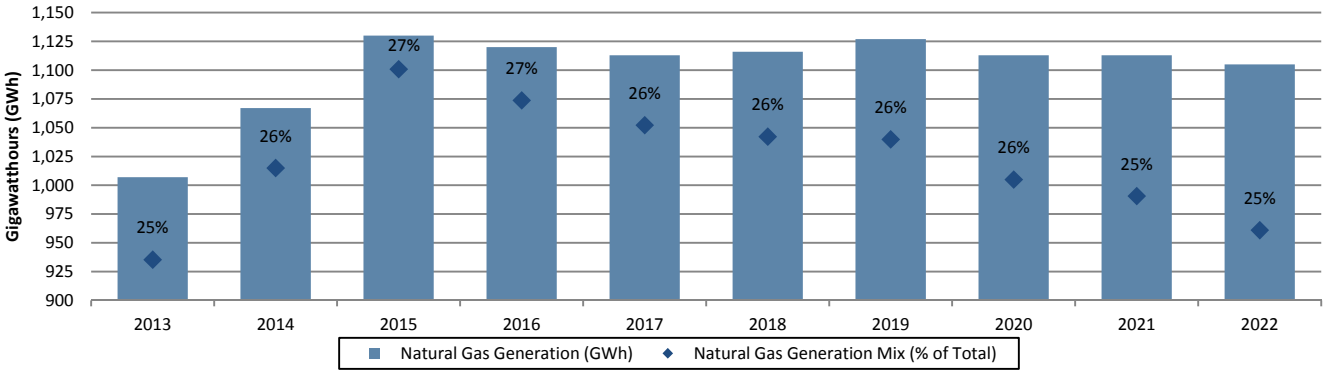
[47] Source: Ventyx Velocity Suite, An ABB Company; modified by NERC staff to reflect NERC footprint. Text boxes added by NERC staff.

Figure 16: Future Gas-Fired Capacity Serves Over Half the Projected Peak Demand



Historically, the power industry has relied heavily on fuel diversification for generating electricity. While there are regional differences, diversification strategies have had a number of significant benefits for the power industry. However, with the projected increases in capacity of gas-fired generation along with the projected reductions in coal capacity, gas-fired generation will be called upon more often. Gas-fired generation will be used to meet base, intermediate, and peak load requirements, effectively increasing overall capacity factors. According to its *2012 Annual Energy Outlook*,[48] the Energy Information Administration (EIA) is projecting an approximately 110 GWh increase in gas-fired generation, effectively increasing gas-fired generation to over 27 percent of all electric generation in 2015 and trailing off to 25 percent in the long term (Figure 17).

Figure 17: Gas-Fired Generation Significantly Increases Over Next Three Years



As shown in the NERC Phase I study on increasing gas dependencies, reliability challenges are more likely to occur during the winter season.[49] While electric generation is generally able to schedule and secure gas during the summer to meet seasonal peak demand, this flexibility decreases during winter months when pipelines tend to peak and firm transportation customers have scheduled their full entitlements. Cold weather can also be responsible for increased infrastructure and supply disruptions, which are generally caused by freezing. Risks to gas well-heads, generators, and pipeline infrastructure due to freezing can expose the electric industry to significant capacity shortages. It is important to understand that while firm gas transportation significantly decreases the likelihood that fuel delivery will be curtailed, extreme events, such as well-head freeze-offs causing decreased gas production (a "force majeure" event),[50] could potentially lead to common-mode failures of a significant amount of gas-fired generators. Additionally, pipeline customers with gas use is designated as

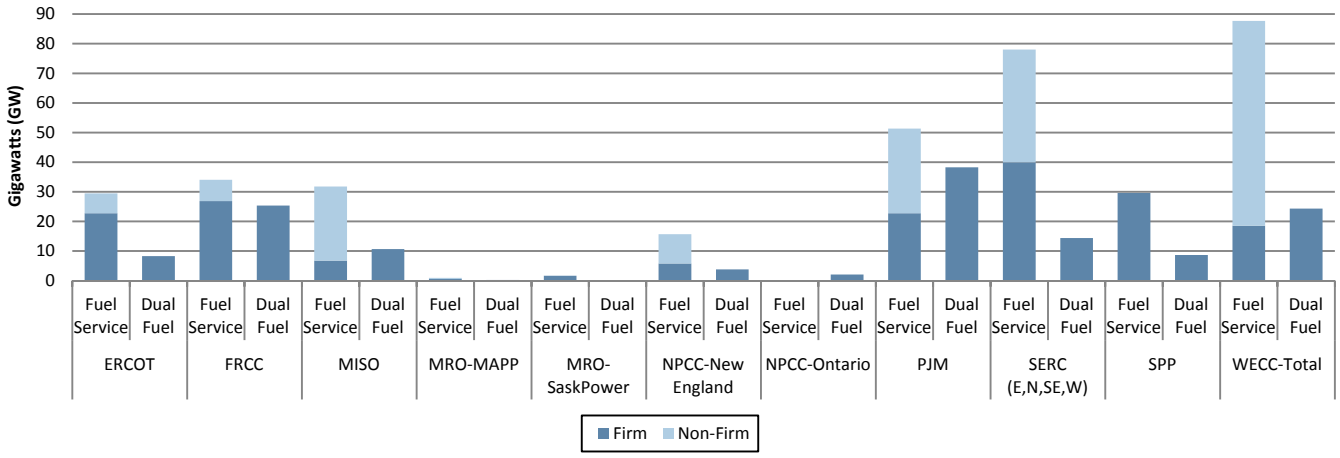
[48] U.S. Energy Information Administration's (EIA's) Annual Energy Outlook 2012 (AEO2012): www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.
[49] 2011 Special Assessment Report: A Primer of the Natural Gas and Electric Power Interdependency in the United States, http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf
[50] Such agreements in fuel contracts relieve the lessee from liability for breach, if the party's performance is impeded as the result of a natural cause that could not have been anticipated or prevented. This act of God must completely prevent performance and must be unanticipated.

"human use" (typically local distribution companies and some commercial customers) always receive priority over electric generation, which during emergencies and restoration efforts can have an impact to gas-fired generation—even with pipelines that have Firm capacity rights.

Dual fuel capabilities and a variety of storage options may help bridge the gap between the uncertainties of gas availability during extreme events and maintaining a reliable source of capacity available to meet seasonal peak demands. Ultimately, the right balance of firm pipeline capacity, dual-fuel capabilities, and a variety of storage options will be regionally dependent. Factors such as market structure, geography, fuel mix, and pipeline infrastructure will determine the extent of gas dependency risks as well as what solutions are available.

Improvements in system reliability may be realized from having sufficient back-up, dual-fuel switching capabilities. Obstacles to achieving such benefits include operational preparedness and state, federal, and provincial environmental regulations, which effectively limit the amount of oil that can be burned. Current policies and rules that regulate back-up oil use and emissions for electric generation may need to be evaluated to ensure dual-fuel capability can be maintained during emergencies or other extreme conditions. Additionally, planning processes should consider back-up fuel inventories, changes in ramp and unit power capabilities, and the time requirements for fuel switch-over. Without considering this information, the amount of available dual-fuel generation projected to be available may be overstated. Currently, 125 GW of gas-fired generation has dual-fuel capabilities, and 58 percent of gas-fired generation is tied to firm supply, transportation, and delivery (Figure 18).

Figure 18: NERC-Wide Gas-Fired Generation Fuel Services and Dual Fuel Capabilities[51]



In early February 2011, a cold-weather event impacted a significant amount of electric generation in Texas, Arizona, and New Mexico.[52] While much of the impact was related to insufficient weatherization, there were some issues with gas supply and transportation. For the southwest as a whole, 67 percent of the generator failures (by MWh) were due directly to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, and low temperature cutoff limits. At least another 12 percent were indirectly attributable to the weather (occasioned by natural gas curtailments to gas-fired generators and difficulties in fuel switching). Natural gas production losses stemmed principally from three causes: gas well-head freeze-offs, icy roads limiting field crew's access to remote well-head sites, and rolling electric blackouts or customer curtailments impacting gas production equipment.

[51] This analysis shows results of where fuel service is known. Areas which did not provide results, and may have unknown fuel service, are not shown.

[52] Joint FERC / NERC Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011, http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

While extreme cold weather is less common in the Southwest, these conditions can arise every few years, without substantial warning. Significant progress has been made to both the gas and electric industries' preparations for managing extreme cold weather events. Weatherization and enhanced emergency operating procedures have been implemented because of the event and will be highlighted in the *2012/2013 Winter Reliability Assessment*.[53]

It is inherent in the electric industry's role of providing reliable electricity to its customers to manage risks. However, it is important to recognize that reliability comes at a cost, and the electric industry must maintain reliability, regardless of the constantly shifting resource mix. The issue of deciding between reliability and cost must be addressed appropriately by all participants of both industries. Industry regulators have a paramount responsibly to find common ground.

NERC will soon release a second phase of its ongoing assessment of the increased dependency on natural gas-fired generation.[54] In its role of continuing to assess the reliability of the BPS through periodic and special reliability assessments, NERC realized the necessity to identify more specific reliability needs. The NERC Phase II effort on increasing gas dependency focuses on the different vulnerabilities that can affect BPS reliability, identifying ways that could minimize those vulnerabilities, and identifying approaches in which coordinated inter-industry activities could provide enhanced system reliability. While solutions will be vast and Region-specific, NERC must ensure that enhancements to planning processes are made to account for any expected uncertainty in gas-fired generation performance as well as potential contingencies on the pipeline network. Furthermore, operational procedures must include a certain level of formalized coordination with the gas pipeline industry, with specific focus on emergency procedures during extreme events.

Risk Assessment Summary

Impacted Assessment Area(s)	ERCOT
	NPCC-New England
	MISO
	PJM
Impact Type	Resource Adequacy - Significant (common-mode) generator outages can cause capacity deficiencies.
	Operating Reliability - Transmission system impacts could manifest from significant gas-fired generator outages.
Magnitude of Impact	During extreme cold weather conditions, gas-fired generation with neither firm transportation nor dual-fuel capabilities may not be available to produce electricity.
	A significant gas supply or pipeline disruption can cause a substantial portion of gas-fired generation to be unavailable.
Likelihood of Impact	Highly dependent on winter weather conditions
	Increase in gas generation and capacity is expected by 2015
	In the past 40 years, at least one significant event has occurred during each 10-year period—at least two major events occurred between 2002 and 2011.

Recommendations

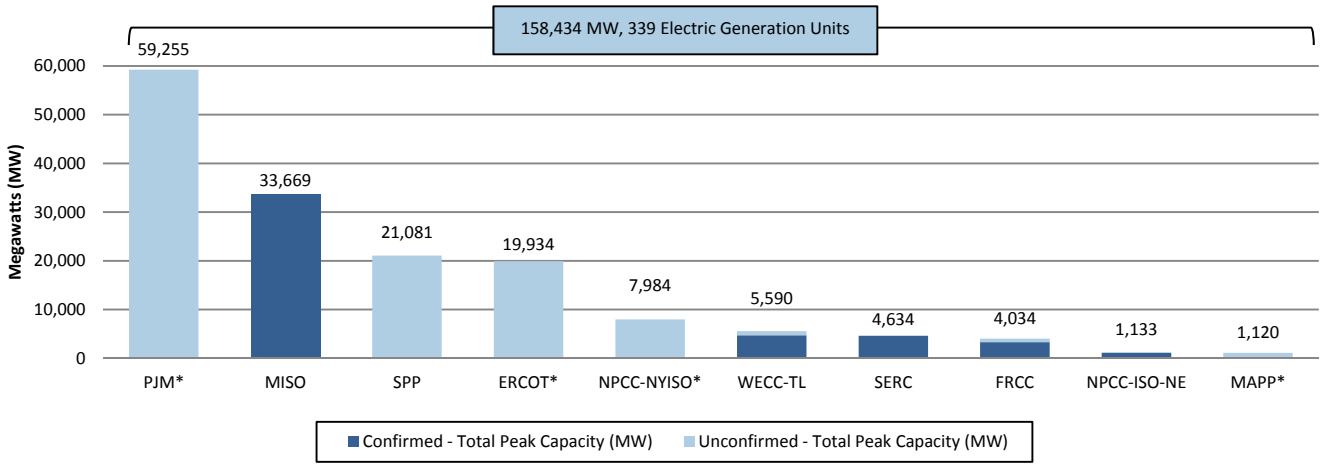
NERC	Identify guidelines, recommendations, alerts, or enhancements to reliability standards that support minimizing risks associated with natural gas dependencies.
	Consider incorporating fuel risks and capacity impacts into resource adequacy and reliability assessments.
	Enhance seasonal assessments of gas-fired generation availability by identifying fuel transportation types and dual-fuel reliability metrics.
	Assess industry plans and procedures to mitigate severe fuel disruptions.
Planning Coordinators, Reliability Coordinators and Balancing Authorities	Enhancements to BPS planning processes that account for uncertainty in gas-fired generation performance should be considered.
	Operational procedures should include a certain level of formalized coordination with the gas supply and pipeline industry, as well as emergency procedures during extreme events
Regulators	State regulators should evaluate the associated risks of gas supply and transportation disruptions and ensure these risks are consistent with a level of risk that is known, expected and planned.
	Current policies and rules that regulate back-up oil use and emissions for electric generation may need to be evaluated to ensure dual-fuel capability can be maintained during emergencies or extreme conditions.

[53] NERC reliability assessment reports: http://www.nerc.com/page.php?cid=4|38.
[54] NERC Gas and Electric Interdependency activities: Phase I and II study scope: http://www.nerc.com/docs/pc/ras/Draft2011GasStudyScope.pdf.

Long-Term Generator Maintenance Outages for Environmental Retrofits

A significant retrofit effort is expected over the next 10 years in order to comply with federal and state-level environmental regulations. A majority of environmental controls are expected to be put in place to meet air regulations by April 2016. In total, 339 unit-level foss-fired generation retrofits will be needed, totaling about 160 GW.[55] However, there is still significant uncertainty in the "unconfirmed" values as maintenance schedules have not yet been fully evaluated by all areas (Figure 19).

Figure 19: NERC-Wide Confirmed & Unconfirmed (Projected) Maintenance Outages for Environmental Control Retrofits through 2016



Complying with proposed environmental regulations may result in generation capacity not being available during shoulder months and off-peak times during the operating day in the near-term (2013–2016).[56] Within this timeframe, some generators may not have enough time to acquire permits, procure engineering services, design equipment, and systematically shut down units for the purpose of retrofitting, while concurrently meeting reliability goals. Deactivations or temporary de-ratings associated with generating unit retrofits may avoid the need to procure replacement resources, but they introduce additional complexities with scheduling outages to avoid temporary shortages that may occur if too much capacity is taken out of service at the same time.

The challenge of timing and scheduling numerous major construction projects, both generation and transmission, to maintain system reliability and avoid having key facilities unavailable at the same time, include:

- Compressed timelines
- Uncertainty related to scope of materials, equipment needs, and availability of skilled labor for these projects
- Market forces outside of the entity's control that could impact cost and delivery times of long lead items (fans, large motors, transformers, fabricated equipment, etc.)
- Outage durations, some as long as 12 weeks at a time, to cover tie-ins and fan upgrades for baghouses and SCRs
- Conflicts in outage windows due to the coordination of new compliance-related projects/outages and existing transmission construction programs and outages, located internally and externally to an area's service territory
- Managing reliability risks for units that will share common environmental controls such as common scrubbers or baghouses

[55] These values do not include retrofits that would be needed to meet 316(b) compliance, as this rule has not yet been finalized and plans have not yet been established. Additionally, areas marked with a (*) were unable to provide this data at this time as the information is not available. In these cases, estimates from NERC's *2011 Long-Term Reliability Assessment* were used and potential retrofits for 316(b) are included.

[56] The shoulder months of the electric year are from March 1 through May 30 and October 1 through November 30.

Generators that are required to retrofit their plants with environmental controls and have chosen to remain online must be in compliance with MATS by 2016 or submit a request for a waiver or extension—specifically, an Administrative Order.[57] With a significant amount of retrofits to be completed from now (late 2012) through 2016, reduced system flexibility during off-peak periods could be encountered. Given the window for completing retrofits, many affected units may need to take long-term maintenance outages concurrently. Taking multiple units out of service for extended outage periods can aggravate resource adequacy and reduce system flexibility and dispatch options, especially during seasons considered "off-peak". Therefore, outage and retirement coordination must be a priority for the industry. If a reliability critical generator cannot come into compliance with the MATS by April 2016, it may request from the EPA an Administrative Order to come into compliance by as late as April 2017, following the pathway described in the December 16, 2011 policy document.

The EPA will rule on a generator's requests for an Administrative Order (AO) to operate in noncompliance with the EPA's Mercury and Air Toxics Standards (MATS).[58] As stated in the EPA Policy Memorandum, on a case-by-case basis, the EPA may rely on identification or analysis of reliability risks upon the advice and counsel of reliability experts, including, but not limited to FERC, RTO/ISOs, Planning Authorities, NERC, and state public service or utility commissions. However, the decision to grant an AO to an owner/operator rests entirely with EPA. NERC, in concert with the Regional Entities, may be requested by the EPA to provide a reliability assessment in relation to a pending AO request. This assessment may include review of the recommendations, a resource adequacy assessment of the given area, gathering of additional information, and additional study if required. Further, it may include all requirements for a reliable power system, including impacts on Planning Reserve Margins, effects on local, regional, and interconnection-wide operational reliability, and review of the expected operating procedures that system planners and operators will use to address NERC Reliability Standards. These studies include a measure of resource adequacy, power flow, transient stability, and system restoration plans. Plans for transmission outage coordination (inter- and intra-regional) may also be needed to implement necessary transmission upgrades. To the extent that potential violations to NERC Reliability Standards are identified, FERC may also provide comments to serve as guidance for EPA on whether there might be a violation of a Reliability Standard.[59]

Compressed compliance deadlines may challenge the electric industry's planning horizons, existing planning processes, and typical construction schedules. Successful implementation of environmental regulation compliance will be highly dependent on the ability of units needed for reliability to obtain the necessary time needed to comply with certain requirements. Given the timelines for compliance, many of the affected units may need to take maintenance outages concurrently. The need to take multiple units out of service on extended scheduled outages can exacerbate resource adequacy concerns and reduce needed flexibility, even during off-peak periods. Outage coordination must be a priority to avoid resource adequacy concerns during maintenance periods.

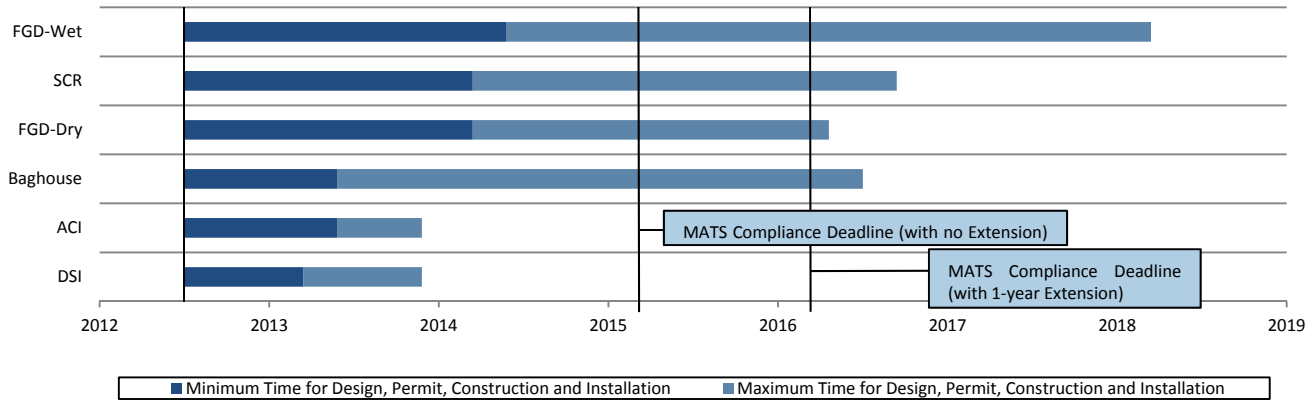
The timelines for retrofits vary by technology. Some retrofit technologies, such as flue gas desulfurization (FGD) and selective catalyst reduction (SCR), are riskier than others because of the length of time it takes to complete the work compared to the deadlines for compliance. It may be possible to receive an additional one-year AO beyond the first-year extension, extending the compliance deadline into 2017. This second-year extension will likely be limited to unique cases, but does offer the flexibility that is needed to ensure generators that are critical for reliability can operate.

Existing authorities should be used to provide extensions where justified. Unit outages for maintenance due to retrofits will affect both the capability to retrofit existing plants to meet required emission targets and the ability of industry to coordinate the necessary outages in order to perform the retrofit. For example, to meet the MATS rule, one possible retrofit solution is to install an air scrubber. It takes approximately 18 months—including planning and installation—for an air scrubber to be installed into an existing facility, as scrubbing equipment is unique to each generator (Figure 20).

[57] http://www.epa.gov/mats/pdfs/EnforcementResponsePolicyforCAA113.pdf
[58] The EPA's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury and Air Toxics Standard (Dec. 16, 2011), http://www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf.
[59] The Commission's Role Regarding the EPA's Mercury and Air Toxics Standards: http://www.ferc.gov/whats-new/comm-meet/2012/051712/E-5.pdf.

However, scrubbers are not expected to be the premier choice for environmental controls at this point in time as some Regions have indicated that direct sorbent injection (DSI) has been selected for a majority of known retrofits (activated carbon injection (ACI) has also been selected). Therefore, longer-term maintenance outages spanning over a year are only expected for a fraction of retrofits.

Figure 20: Retrofit Project Timelines Relative to MATS Compliance Deadlines



With the limited outage windows before the 2016 compliance deadline, it will be increasingly important for the outage coordination groups to have as much information as possible. In MISO, the development of a monthly maintenance margin will aid in outage scheduling and will be updated seasonally to reflect current information.[60] As part of MISO's efforts to best manage an expected influx of outage requests associated with recent environmental regulations, MISO conducted an outage limit analysis to determine acceptable monthly outage levels that can be allowed to maintain reliable transmission operations.[61]

MISO's supply chain analysis,[62] conducted by The Brattle Group, concluded that the March 2015 timeline requires more construction than the industry has seen in the past and the greatest unknown risk is the amount of skilled labor available to perform the retrofits. In addition, the type of technology necessary to bring a unit into compliance may require lengthy unit outages that may run past the compliance deadline.

In PJM, significant uncertainty remains in the projections for maintenance outages. However, PJM will continue to coordinate closely with BPS owners and operators in the area to analyze the impact of retiring generation, planned outage to perform retrofits, and transmission maintenance outages required to reliably take retiring units out of service. Generation Owners have indicated that while there appears to be sufficient time to complete environmental retrofits, if there are delays in scheduling retrofit outages due to system constraint issues or capital budget limitations, then there may be significant challenges in completing the retrofit outages in the required time to comply with environmental regulations.

In SPP, it is expected that the impact of retrofits will constrain the availability and increase the costs of qualified labor, materials, and heavy equipment. These constraints, as well as the need to coordinate outage scheduling and complete localized transmission reinforcement projects, will likely result in the compliance deadlines for certain units be extended. SPP RTO is maintaining regular contact with individual entities to ensure that any specialized assessments can be completed in time to identify and address circumstances in which additional time may be warranted. Surveys are still being completed regarding expected retrofit and retirement plans, and SPP RTO expects to complete an initial analysis of this issue by the end of the year.

[60] https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/EPA_Outage%20Limits%20Analysis.pdf.
[61] https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/EPA_Outage%20Limits%20Analysis.pdf.
[62] https://www.midwestiso.org/Library/Repository/Communication Percent20Material/Key Percent20Presentations Percent20and Percent20Whitepapers/Supply Percent20Chain Percent20and Percent20Outage Percent20Analysis Percent20of Percent20MISO Percent20Coal Percent20Retrofits Percent20for Percent20MATS.pdf

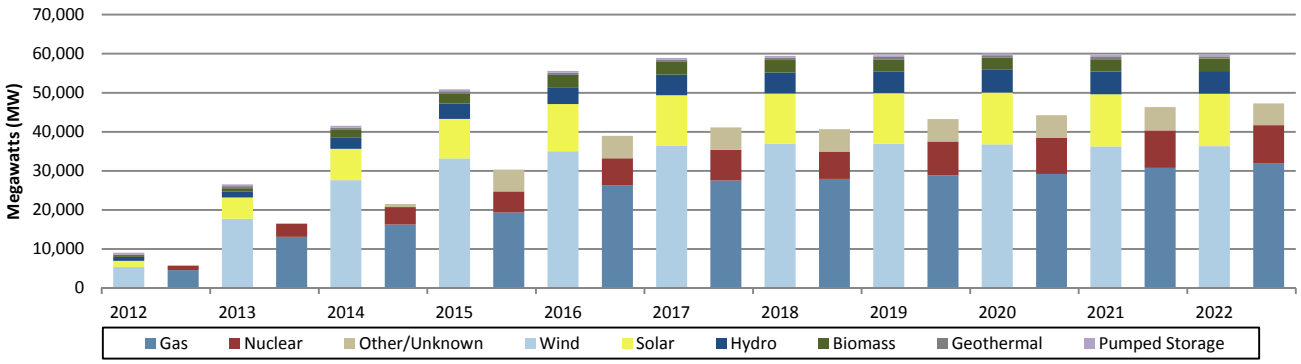
Risk Assessment Summary	
Impacted Assessment Area(s)	MISO
	PJM
	SPP
Impact Type	Resource Adequacy - Longer than expected maintenance outages can result in off-peak resource adequacy concerns.
	Operating Reliability - The aggregated impact of multiple unit outages, combined with unforeseen system stresses, can impact system stability.
Magnitude of Impact	339 generation unit retrofits, comprising of almost 160 GW of capacity
Likelihood of Impact	Dependent on delays in retrofits and scheduled maintenance
	While there are often procedures to manage and coordinate generator outages, unforeseen events can reduce the system operator's ability to perform corrective actions.

Recommendations	
NERC	NERC should evaluate the retrofit efforts of generators in North America within its seasonal reliability assessment.
Regulators	ERCOT should continue to consider alternative solutions to the resource adequacy issues.
	Regulators should provide extensions where justified by independent authorities on electric reliability.

Renewable Resource Additions Introduce New Planning and Operational Challenges

Renewable resources are growing in importance in many areas of North America as the number of new facilities continues to increase. Nameplate renewable capacity (including wind, solar, hyro, biomass, geothermal, and pumped storage) will grow by approximately 60 GW by 2022, outpacing any other resource (Figure 21). Wind contribution during the peak is typically only a fraction of the nameplate capacity, which grows by over 36 GW during the assessment period. Solar and bioass will grow by 13.4 and 3.1 GW, respectively. A majority of the 580 GW of geothermal capacity additions will occur in the first two years of the assessment period (by 2014). The same case applies to pumped storage resources, which will grow to 466 MW by 2014 and remain constant through 2022.

Figure 21: Cumulative Future-Planned Nameplate Renewable Capacity Additions Compared to Non-Renewable Capacity Additions



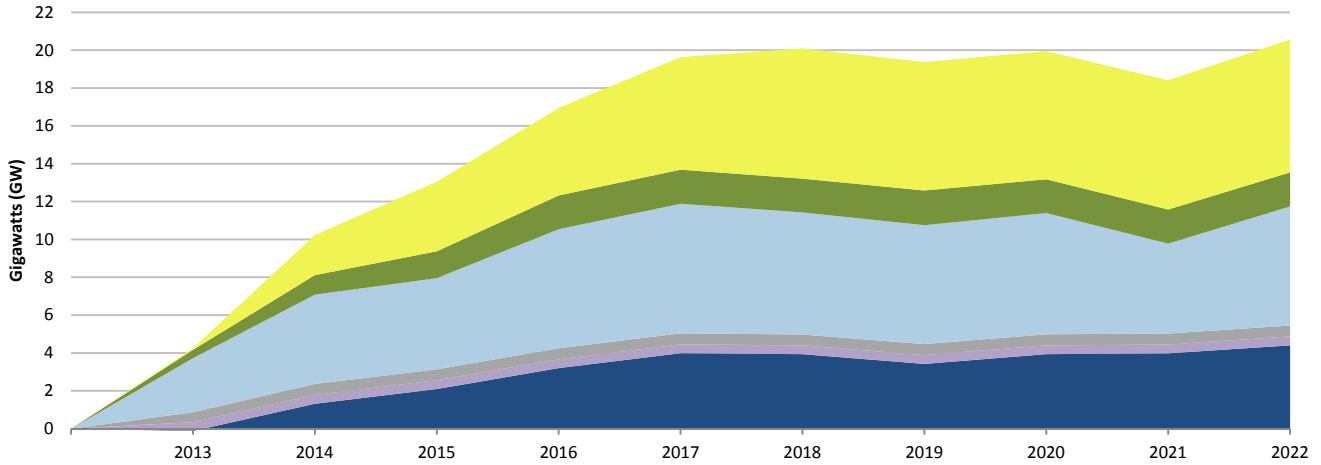
Overall capacity contribution from renewable resources will continue to grow, especially as significant additions are projected for both wind and solar throughout North America. In 2012, renewable generation, including hydro, made up 15.6 percent of all on-peak capacity resources and is expected to reach almost 17 percent in 2022 (Figure 22). Contributing to this growth is approximately 20 GW of on-peak planned capacity and an additional 21.5 GW of on-peak Conceptual capacity. It is vital that these variable resources are integrated reliably and in a way that supports the continued performance of the BPS and addresses both planning and operational challenges.[63]

Managing the variability of wind and solar resources will require more flexibility in the power system. The changes in the bulk power system flows from both the variable generation and demand response implementation must be better understood. The NERC Integrating Variable Generation Task Force (IVGTF) has completed significant work over the past three years to address enhanced planning and operational reliability considerations when accommodating large amounts of variable generation.[64] The scope of work has addressed not only system-specific considerations, but also those from a regional and North American perspective.

[63] Accommodating High Levels of Variable Generation: Summary Report: http://www.nerc.com/files/Special%20Report%20%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf.

[64] Completed variable generation assessments and recommendations produced by the IVGTF: http://www.nerc.com/page.php?cid=4|61

Figure 22: On-Peak Future-Planned Renewable Capacity – Cumulative Net Change



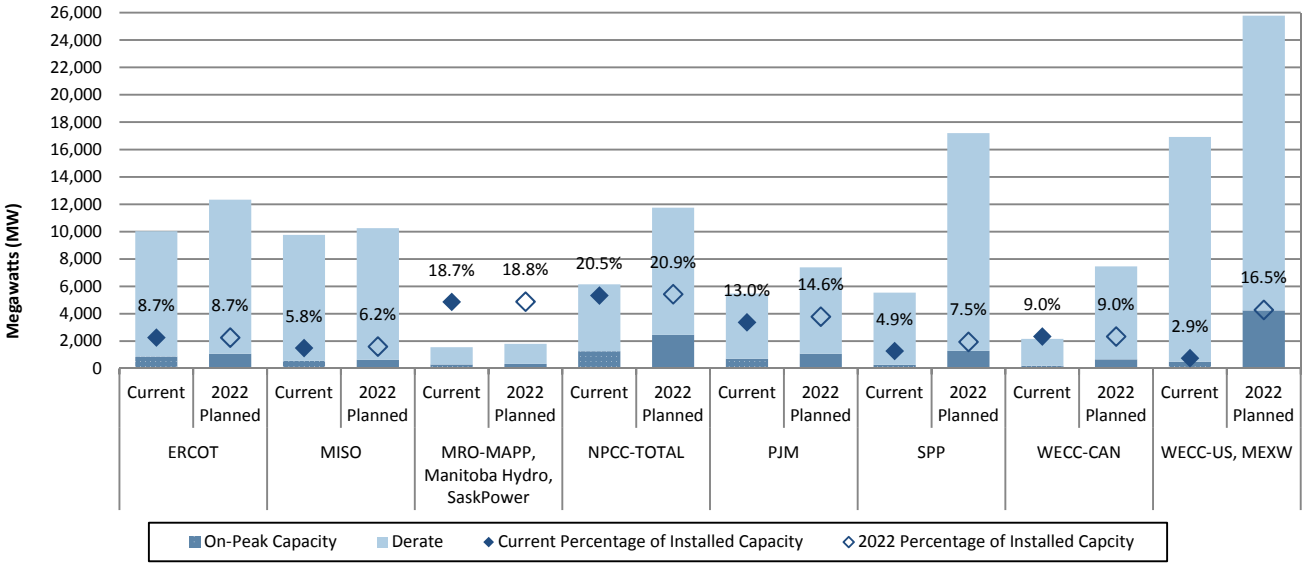
	Current		2022 Planned			2022 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	124,332	77.50%	128,742	71.01%	4,410	131,175	58.50%	6,843
Pumped Storage	21,697	13.53%	22,162	12.22%	465	22,627	10.09%	930
Geothermal	2,584	1.61%	3,333	1.84%	749	4,082	1.82%	1,498
Wind	5,219	3.25%	11,505	6.35%	6,286	32,105	14.32%	26,886
Biomass	4,780	2.98%	6,736	3.72%	1,956	8,692	3.88%	3,912
Solar	1,809	1.13%	8,833	4.87%	7,025	25,555	11.40%	23,747
TOTAL	**160,420**	**100.00%**	**181,311**	**100.00%**	**20,891**	**224,235**	**100.00%**	**63,815**

A key goal for power system planners is not only to determine how much capacity there is on a system, but also to determine if that capacity can be reasonably expected to perform and operate on peak. Because wind power output is often inversely correlated with demand in some regions, capacity output of wind plants during times of peak demand generally amounts to a fraction of nameplate capacity (Figure 23). For example, the "expected on-peak capacity" can account for as little as 3 percent of a given area's entire nameplate wind capacity. As noted by NERC in prior assessments, consistent methods to determine on-peak wind capacity are needed to ensure uniform measurement and resource adequacy assumptions.[65] As wind generation becomes a more significant contributor to an area's capacity mix, probabilistic planning techniques will be needed. Probabilistic planning techniques indicate that in most areas wind's contribution to capacity are generally in the range of 5 to ten percent of the wind energy nameplate capacity.[66] Currenly, only MISO and ERCOT have a probabilistic basis for determining this factor. More consistency is being achieved due to more experience with larger portfolios of wind generation.

[65] Currently, Regions and subregions (in particular, difference operating entities) use different methods to determine expected on-peak values of wind capacity. The Integration of Variable Generation Task Force is addressing this issue. The report *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* is available on the NERC website at: http://www.nerc.com/files/IVGTF1-2.pdf

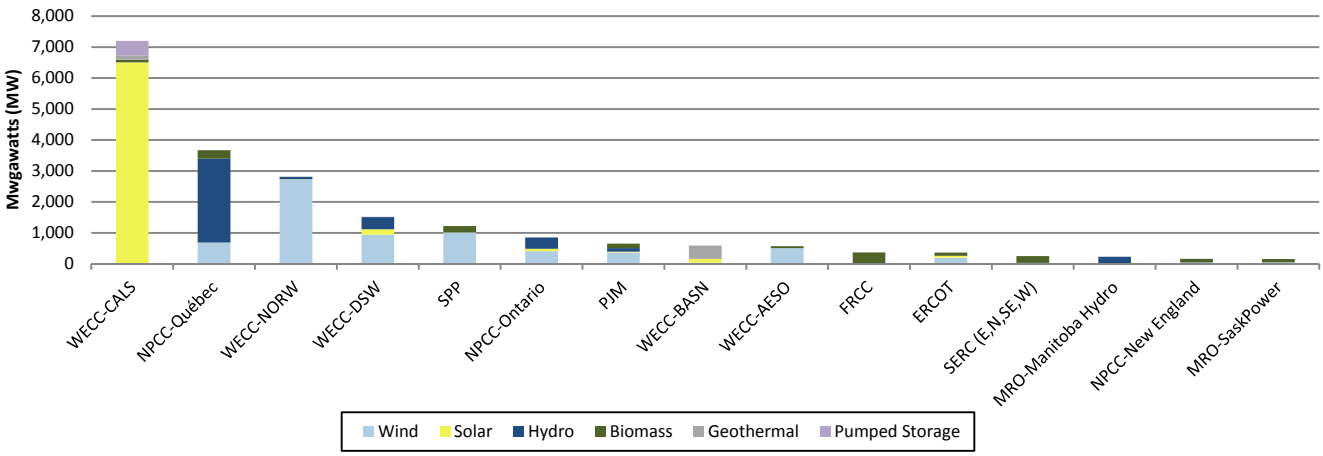
[66] http://www.nerc.com/docs/pc/ivgtf/ieee-capacity-value-task-force-confidential%20%282%29.pdf

Figure 23: On-Peak Renewable Capacity – Cumulative Net Change[67]



From an assessment area perspective, southern California is expecting the most future renewable on-peak capacity with over 13 GW of new solar capacity. Significant on-peak wind capacity is projected in both the United States and Canada, totaling an increase of over 7.4 GW in WECC alone (Figure 23).

Figure 24: On-Peak Renewable Capacity – Planned Additions by 2022[68]



Solar generation will see more growth in both nameplate and on-peak capacity during the next 10 years (Figure 25). Plans for approximately 13.4 GW of nameplate capacity are projected to come into service, primarily in the WECC-CALS and WECC-DSW subregions. Regional planners in these areas continue to assess the growing impacts of this variable resource into the generation mix. One notable difference is the expected on-peak capacity that can be reliably counted on to serve peak demand. Across the dense installations of solar capacity in the Southwest, the two WECC assessment areas are counting on approximately half of the installed capacity to serve peak demand.

[67] For WECC-CAN, the metric the on-peak wind capacity is based actual performance for the last three winter seasons, as reported in the 2010-2012 LTRA reference cases. WECC is currently developing an enhanced approach to determine capacity contributions from variable generation.

[68] This figure includes only those areas with significant renewable capacity additions and does not include capacity additions classified as Conceptual.

Figure 26: Solar Additions Primarily in the WECC-CALS and WECC-DSW Assessment Areas

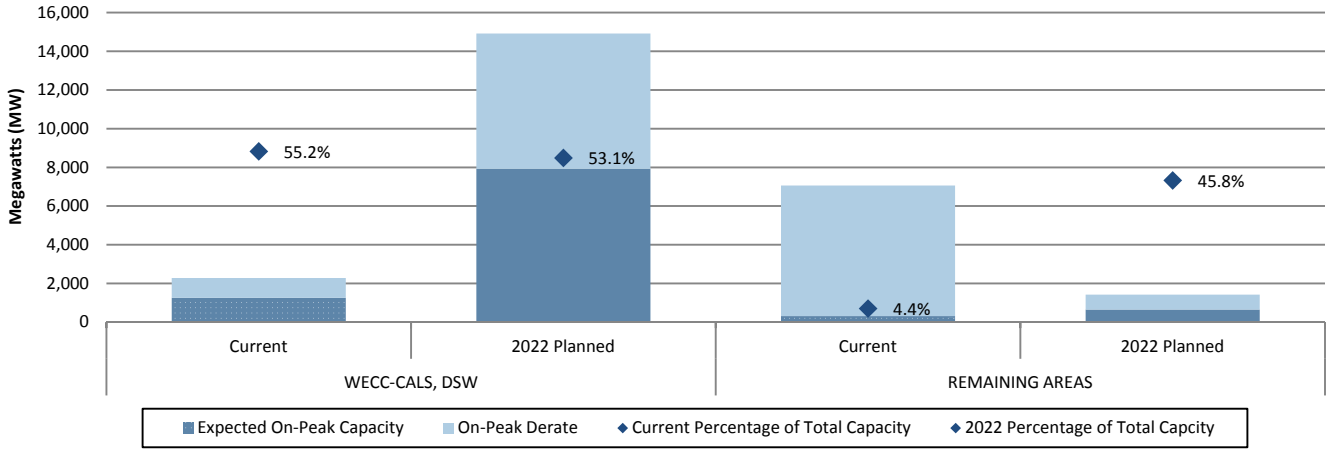
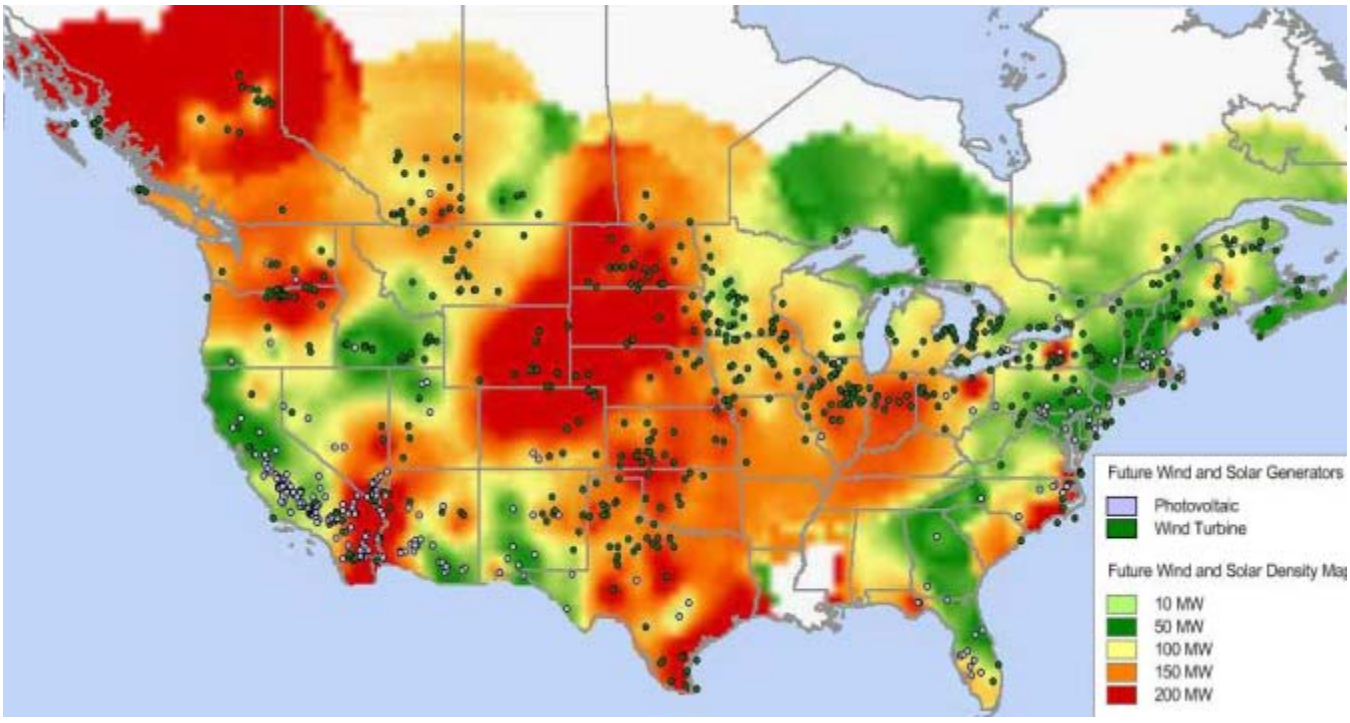


Figure 27: Density Map of Future Wind and Solar Installed Capacity Additions[69]



Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term bulk power system reliability. Power system planning is intended to ensure that a reliable and robust power system is available to the power system operator within the planning horizon. The industry has already begun development of new planning methods and techniques that consider the characteristics of variable generation assets to improve system reliability. These tools need to be expedited to ensure the reliable operation of the bulk power system. New models need to take into account new technologies, such as storage, variable demand such as demand response, and incorporation of flexible resources. For example, storage technologies, if properly planned and implemented can provide the flexibility to accommodate large amounts of variable resources as an alternative to the construction of more conventional flexible generation resources or transmission, if economical.

[69] Source: Ventyx Velocity Suite, An ABB Company, modified by NERC staff to reflect NERC footprint.

Areas integrating wind resources have projected increases in transmission congestion, particularly when demand is low. As wind resources are less predictable and follow the availability of their fuel (wind) rather than dispatch instructions from operators or market based systems for traditional "controlled fuel" plants, different patterns in the use of transmission capacity can emerge from this new variable fuel paradigm. In some cases, renewable resource availability may not be correlated to demand, being available during the nighttime, for example, rather than during daily peak periods. Energy storage may provide potential support by converting this energy to stored capacity. Further, some Regions report challenges in managing the power system under the high variability of wind resources and report the need to provide additional ancillary services (such as operating reserves) as specific challenges (see NERC's *2012 Summer Reliability Assessment*).[70]

Power system planners are already familiar with designing a system that can be operated reliably while accommodating a certain amount of variability and uncertainty, particularly as it relates to system demand and, to a lesser extent, to conventional generation. However, large-scale integration of variable generation can significantly alter familiar system conditions due to increased supply variability and uncertainty. This presents new challenges to power system operators, and planners will need to design a system that can accommodate variable generation in large quantities, providing operators with the resources needed. In addition, system variability occurs from distribution system connected renewables (also called embedded generation). Embedded generation capacity is less visible to system operators and introduces additional variability to the perceived local demand forecast and load served.

Forecasting of variable generation resources is important in all timeframes, and there are many uses for longer-range forecasts from days and weeks (e.g., transmission outage planning and minimum generation issues) to years (e.g., integrated resource planning, where resource flexibility and ramping capabilities should be increasingly valued, and the generation mix if not appropriately planned can raise bigger challenges/issues during operating timeframe). Such longer-term schedules are adjusted as they get closer to real-time and the critical operating impacts to bulk power system reliability tend to be closer to real time.

Regional differences will exist; however, this is largely an interconnection-wide issue as policy and mandates requiring energy from renewable generation expand. As policy and regulations on greenhouse gas emissions, notably CO_2, and mandated Renewable Portfolio Standards (RPS) are being developed by states and provinces throughout North America, and as the economics of renewable resources continue to improve, the addition of renewable generation into the bulk power system is expected to grow considerably in the near future. The level of commitment to renewable resources offers benefits such as new generation resources, fuel diversification, and greenhouse gas reductions. However, renewable commitments present significant new challenges that need to be properly addressed to maintain bulk power system reliability.

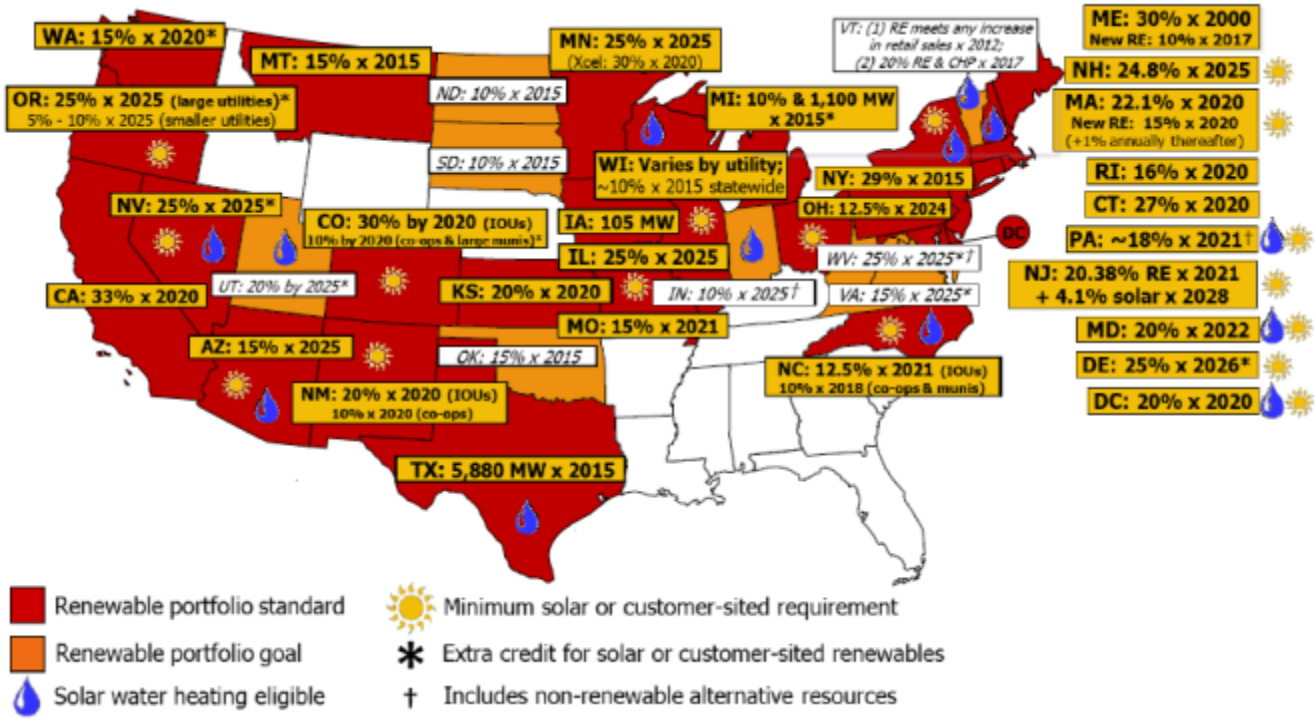
Provincial and state Renewable Portfolio Standards (RPS) will increase renewable resources located where wind power densities and solar development are favorable. Congress is also considering a federal RPS. Grid expansion is needed to support the dispersed nature of renewable resources. The limited timeframe provided to meet RPS mandates requires that current transmission siting and permitting processes be expedited. Federal, state, and provincial CO_2 legislation is pending throughout North America.

In the United States, a number of Regional and state activities have resulted in a variety of renewable portfolio standards. In 2010, NERC's Planning Committee created the Reliability Impacts of Climate Change Initiatives Task Force (RICCITF)[71] to

[70] *2012 Summer Reliability Assessment*: http://www.nerc.com/files/2012SRA.pdf
[71] 2010 Special Reliability Assessment: Reliability Impacts of Climate Change Initiatives: Technology Assessment and Scenario Development, http://www.nerc.com/files/RICCI_2010.pdf

review CO_2 legislative and regulatory impacts on BPS reliability.[72] Further, NERC staff prepared a report documenting industry concerns and reliability considerations (Figure 28).[73]

Figure 28: Renewable Portfolio Targets in Most of the United States[74]



Individual state, provincial, and regional initiatives may not significantly affect BPS reliability. However, these combined initiatives will begin to come to fruition concurrently with federal climate change policies underway in North America. Industry planners should recognize and address potential impacts to meet the following climate change initiatives without compromising system reliability.

- **State and Provincial Renewable Portfolio Standards**: Renewable Portfolio Standards typically require load-serving entities in a given area to acquire a certain percentage of their energy supply from renewable resources by a target year (for example, 20 percent by 2020). Twenty-nine U.S. states and three Canadian provinces have some kind of renewable portfolio standard in place. NERC has studied the reliability consideration resulting from accommodating high levels of variable renewable resources.[75]
- **Other State and Provincial Climate Goals**: All remaining Canadian provinces and six U.S. states have some form of policy in place to address climate change and greenhouse gas emissions, either through specific capacity or energy goals for electric generation or other means.
- **Regional Initiatives**: Initiatives such as the Regional Greenhouse Gas Initiative in the Northeast (RGGI) and Western Climate Initiative (WCI) have created multi-state and cross-border partnerships to reduce greenhouse gas emissions on a regional basis.[76]
- **U.S. Federal Climate Change Legislation**: The U.S. Senate and House of Representatives, as well as the EPA, have considered in the recent past various legislative proposals to reduce carbon dioxide (CO_2) emissions.

[72] http://www.nerc.com/filez/riccitf.html
[73] http://www.nerc.com/files/2008-Climate-Initiatives-Report.pdf
[74] Source: Database of State Incentives for Renewables & Efficiency: http://www.dsireusa.org/.
[75] Numerous special assessments on accommodating high-levels of variable generation: http://www.nerc.com/page.php?cid=4|61
[76] Regional Greenhouse Gas Initiative (http://www.rggi.org/) and Western Climate Initiative (http://www.westernclimateinitiative.org/)

As states and provinces begin adopting a variety of approaches to greenhouse gas emission regulation, the prospect grows for federal regulation. Further, an April 2007 United States Supreme Court decision[77] determined greenhouse gas regulation fell under the purview of the U.S. Environmental Protection Agency.

Transmission

Transmission planning processes to integrate large amounts of variable generation rely on a number of factors, including:

- Whether government renewable policies or mandates exist;
- Level of variable generation mandated and available variable generation in remote locations;
- Time horizon across which capital investments in variable generation are to be made; and
- Geographic footprint across which the investments occur.

In order to ensure reliability, transmission is needed to achieve the following:

- Interconnect variable energy resources planned in remote Regions
- Accommodate the variable generation output with uniformity across a broad geographical region and resource portfolio
- Deliver ramping capability and ancillary services from inside and outside a Balancing Authority area to equalize supply and demand

Transmission system expansion is vital to unlocking the capacity available from variable generation. In those Regions with a competitive generation marketplace, regulatory targets such as Renewable Portfolio Standards heavily influence the location and timing of renewable generation investments and their development. Furthermore, government policy and any associated cost allocations (i.e., who pays for transmission, additional ancillary services, and ramping capability) will be a key driver for variable generation capacity expansion. Therefore, an iterative approach between transmission and generating resource planning is required to cost-effectively and reliably integrate all resources.

Transmission expansion, including greater connectivity between Balancing Authorities, and coordination on a broader regional basis, is a tool that can aggregate variable generators and lead to the reduction of overall variability. Sufficient transmission capacity serves to accommodate the output of individual variable and conventional generation plants across a broader geographical region. Large balancing areas or participation in wider-area balancing management may be needed to enable high levels of variable resources. As long as existing transmission pathways are not congested, transmission expansion may not be required to achieve the benefits of larger balancing areas. Shared ramping capability and ancillary services between adjacent areas also provide additional reliability benefits, depending on how existing and planned inter-area transmission assets are used.

Currently, high-voltage transmission overlay expansions are being conceptualized in various parts of the NERC footprint. High-Voltage Alternating Current (HVAC), High-Voltage Direct Current (HVdc) transmission, or a hybrid of both provides expansion alternatives for this overlay approach. HVAC can interconnect to the existing AC grid to support new generation and load centers as the grid evolves. However, for very long, over-ground distances (wind sites are often hundreds of miles away from demand centers), dedicated HVdc may be a more suitable solution. In addition to long distances, offshore applications also offer technical challenges that can preclude HVAC cables. With the advent of voltage-source converter (VSC) technologies, additional HVdc benefits (e.g., reactive power control voltage and frequency control) have proven useful in other renewable energy projects, such as offshore wind plants, and can be useful in many other generation projects as well.

[77] http://www.supremecourtus.gov/opinions/06pdf/05-1120.pdf

Risk Assessment Summary	
Impacted Assessment Area(s)	ERCOT
	MISO
	SPP
	WECC
Impact Type	Resource Adequacy - Large and unexpected down ramps can contribute to a capacity shortage.
	Operating Reliability - Distributed and variable generation can have unforeseen impacts to system stability and voltage support if not sufficiently modeled.
Magnitude of Impact	Sufficient transmission is needed to reliably interconnect 80 GW of projected renewable generation on-peak capacity.
	Renewables are expected to provide 20 percent of expected on-peak capacity in 2022. This value reflects de-rates for nameplate renewable resources.
Likelihood of Impact	The likelihood of an event that impacts reliability is greatly reduced if proper planning processes, operational procedures, and operator training have been implemented.
	Increasing operator experience with variable resource characteristics and behaviors should enhance system operators' ability to manage unpredicted events.

Recommendations	
NERC	The IVGTF should complete their work on planning and operating requirements for integrating large amounts of variable generation.[78] • NERC should address recommendations for adopting probabilistic approaches for determining capacity contributions of variable generation.[79] • NERC should enhance its Reliability Standards by organizing Standard Authorization Requests or supporting existing standard development processes that have been identified by the Integration of Variable Generation Task Force: o Distributed Resources[80] o Standard Models[81] o Interconnection Requirements[82] • NERC should develop metrics that measure flexibility needs for variable generation.[83] • Recommendations for operational planning and real-time operations o Forecasting[84] o Operating Criteria and Ancillary Services[85] o Operating Practices, Procedures, and Tools[86]
Generator Owners and Operators	Variable Generator Owners should explore whether their resources have the technical abilities of providing enhanced (ancillary) services to the BPS.
Planning and Reliability Coordinators	Requirements for operational flexibility and reliability criteria should be re-examined for systems with large amounts of variable resources.

[78] http://www.nerc.com/filez/ivgtf.html
[79] http://www.nerc.com/files/IVGTF1-2.pdf
[80] http://www.nerc.com/files/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011%20%282%29.pdf
[81] http://www.nerc.com/files/Standards%20Models%20for%20Variable%20Generation.pdf
[82] http://www.nerc.com/files/2012_IVGTF_Task_1-3.pdf
[83] http://www.nerc.com/files/IVGTF_Task_1_4_Final.pdf
[84] http://www.nerc.com/files/Varialbe%20Generationn%20Power%20Forecasting%20for%20Operations.pdf
[85] http://www.nerc.com/files/IVGTF2-3.pdf
[86] http://www.nerc.com/files/IVGTF2-4.pdf

Transmission Growth to Accommodate New and Distant Resources

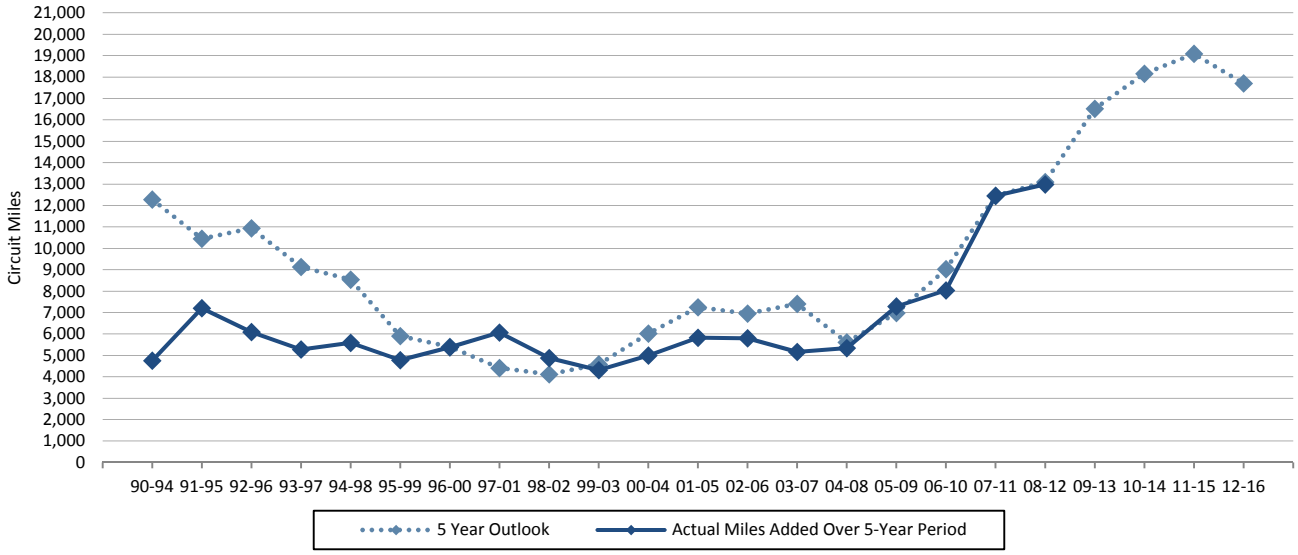
The future reliability of the BPS is largely dependent on the ability to site, permit, and build new transmission assets in a timely manner. The existing electric transmission systems and planned additions over the next 10 years appear adequate to reliably meet customer electricity requirements. However, delays to transmission construction due to permitting and siting have been observed and continue to inhibit the industry from constructing new and potentially vital transmission infrastructure. While these deferments do not currently pose a reliability concern, the importance of a secure transmission infrastructure is amplified when one considers the significant addition of variable generation resources, pending environmental legislation in both the United States and Canada, and increased demand projections throughout North America in the assessment's 10-year horizon. It is important that local, state, provincial, and federal regulators work together to develop timely and effective solutions to minimize potential delays. The process to site new transmission continues to be difficult, time-consuming, and expensive due to local opposition and environmental concerns, especially when lines are planned to cross state borders. Negotiations still delay and, in some cases, stop needed projects from being built. As a result, transmission permitting, siting, and construction can take significantly longer (i.e., 7–10 years) than permitting, siting, and construction of generation.

NERC continues to monitor the progress of transmission projects across North America. While transmission planning is dynamic (i.e., a project is needed one year, but can be deferred due to a change in demand forecasts), plans should reflect realistic expectations in order to reliably support system needs in the future. For example, ERCOT plans to install a significant amount of transmission circuit miles by 2013. Once in-service, these lines will provide ERCOT with better methods to manage existing and potential congestion problems and will support recently completed Competitive Renewable Energy Zone (CREZ) projects in Western Texas. Large transmission line additions and upgrades are also projected within the MISO footprint, with more than half of these upgrades resulting from a need to reliably integrate renewable generation resources. Minor additions are expected throughout the MRO Assessment Areas to integrate hydropower resources in Manitoba and improve reliability in the MAPP Assessment Area while accommodating for projected load growth in SaskPower.

An analysis of the past 16 years shows that planned transmission (greater than 200 kV)[87] during the next five years would nearly triple the average circuit miles that have historically been constructed during a five-year period. Through this analysis period, the number of actual miles constructed over five-year periods has roughly averaged 7,100 circuit miles. During the next five years, about 18,700 miles are planned, which continues to exceed recent historical averages.[88] However, during the previous and consecutive five-year periods (2003–07 through 2007–11), industry was successful in meeting its projections. From 2006 through the end of 2011, industry has exceeded the average transmission additions (circuit miles), constructing the most transmission during a five-year period since the 1991-1995 period[89] (Figure 29). As recent as five years ago, transmission was being constructed at a rate of about 1,000 circuit miles per year. In the last five years, over 2,300 circuit miles were constructed per year, more than doubling actual builds in the previous five years. With the current plans in place, that rate is expected to increase to 3,600 miles per year over the next five years.

[87] Transmission data prior to 2009 is limited to 200 kV and above.
[88] Significant recent and projected transmission additions are still well below additions made 40-50 years ago when much of the current grid was built
[89] 1990 is the first year this type of data was digitized. Previously data was not collected on five-year plans.

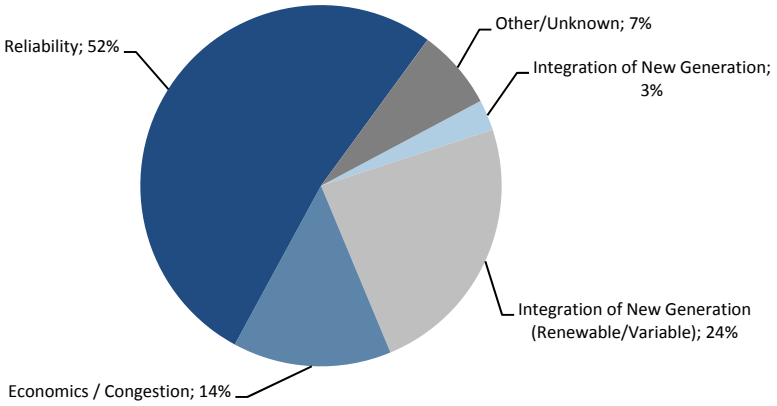
Figure 29: Historical Actual Miles Added for Rolling Five-Year Periods and Projected Five-Year Plans, 200kV and Above[90]



Stakeholders within the electric industry continually assess the ability of their internal transmission system and interconnections with other systems not only to meet regional requirements, but also to meet compliance with NERC Reliability Standards. Once a set of transmission alternatives has been identified, the project can take up to ten or more years to complete from project identification to final certification and energization of elements. A majority of the time in this process is devoted to the siting, permitting, and land acquisition process, which has no definitive time frame and can vary greatly depending on the geographic location of proposed additions.

NERC-wide, almost a quarter of new transmission is specifically linked to the integration of renewable generation. Therefore, areas with larger increases in projected renewables are generally the areas with significant transmission additions. Projected transmission additions in ERCOT, MISO, and WECC are largely due to the future renewable additions that are expected over the next 10 years (Figure 30 and Table 30).

Figure 30: New Transmission Projects (by Circuit Miles) Driven by Reliability and the Integration of Renewable Resources



[90] Historic data has been revised for some areas based on the original submission of erroneous data for existing and planned circuit miles.

Table 31: Planned Transmission Additions by Assessment Area, 2012-2022 (Circuit Miles 100kV and Above)

	Existing		2010-2011	Current	2012-2017		2018-2022		2022 Total Projected	
Assessment Area/Country	2010 Year-End	2011 Year-End	Line Additions	Under Construction	Planned	Conceptual	Planned	Conceptual	E+UC+P	E+UC+P+C
ERCOT	29,107	29,465	358	946	4,757	800	29	391	35,197	36,388
FRCC	11,973	12,031	58	46	249	0	200	97	12,526	12,623
MISO	50,144	44,500	-5,644	161	1,838	63	1,069	0	47,568	47,631
MRO-MAPP	10,314	10,266	-49	230	716	107	0	0	11,211	11,318
NPCC-New England	8,496	8,106	-390	182	458	218	8	18	8,753	8,989
NPCC-New York	10,990	10,992	2	0	138	0	30	0	11,160	11,160
PJM	45,472	51,649	6,177	118	709	131	1,267	134	53,743	54,008
SERC-E	21,995	22,180	185	33	276	87	189	189	22,678	22,954
SERC-N	21,303	21,600	297	254	332	21	13	57	22,198	22,276
SERC-SE	27,316	27,672	356	108	305	66	374	0	28,459	28,525
SERC-W	13,604	14,295	691	72	414	26	79	92	14,860	14,978
SPP	32,857	32,881	24	638	1,613	47	180	103	35,311	35,460
WECC-US	103,371	104,359	988	199	4,093	4,501	1,921	2,598	110,572	117,672
TOTAL-US	386,942	389,995	3,053	2,988	15,895	6,066	5,358	3,678	414,236	423,981
MRO-Manitoba	7,295	7,485	190	0	237	0	1,076	80	8,798	8,878
MRO-SaskPower	4,997	5,083	86	0	323	222	0	0	5,406	5,628
NPCC-Maritimes	5,056	5,082	26	0	13	203	0	283	5,095	5,581
NPCC-Ontario	17,713	17,931	218	93	0	180	0	599	18,024	18,803
NPCC-Québec	23,100	22,787	-313	412	68	546	129	599	23,395	24,539
WECC-Canada	21,489	22,946	1,457	0	1,970	0	706	0	25,623	25,623
TOTAL-CANADA	79,650	81,314	1,664	505	2,611	1,151	1,911	1,560	86,341	89,051
WECC-MEXW	1,425	1,458	33	0	255	0	132	0	1,845	1,845
TOTAL-MEXICO	1,425	1,458	33	0	255	0	132	0	1,845	1,845
TOTAL-NERC	**468,017**	**472,767**	**4,750**	**3,492**	**18,761**	**7,217**	**7,401**	**5,239**	**502,421**	**514,877**

In the United States, the recent issuance of FERC Order 1000 reforms the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers. While the rule provides a framework for cost allocation and requires certain considerations that need to be addressed, the potential benefit the order brings is in its inter-regional transmission planning reform. While many Regions already perform inter-regional planning, the order facilitates the evaluation of large, interconnection-wide issues.

Projected transmission circuit mile additions are an indicator of the relative strengthening of the existing bulk power transmission system. Although the addition of transmission circuit miles is encouraging, the associated increased use of transmission systems due to increased demand growth, generation additions (including geographically distant generation), capacity deficiencies, and the increasingly competitive bulk power market must also be considered when evaluating overall system reliability (Figure 32 and Figure 33).

Figure 32: NERC-Wide Cumulative Transmission Additions by Project Status and Expected In-Service Year

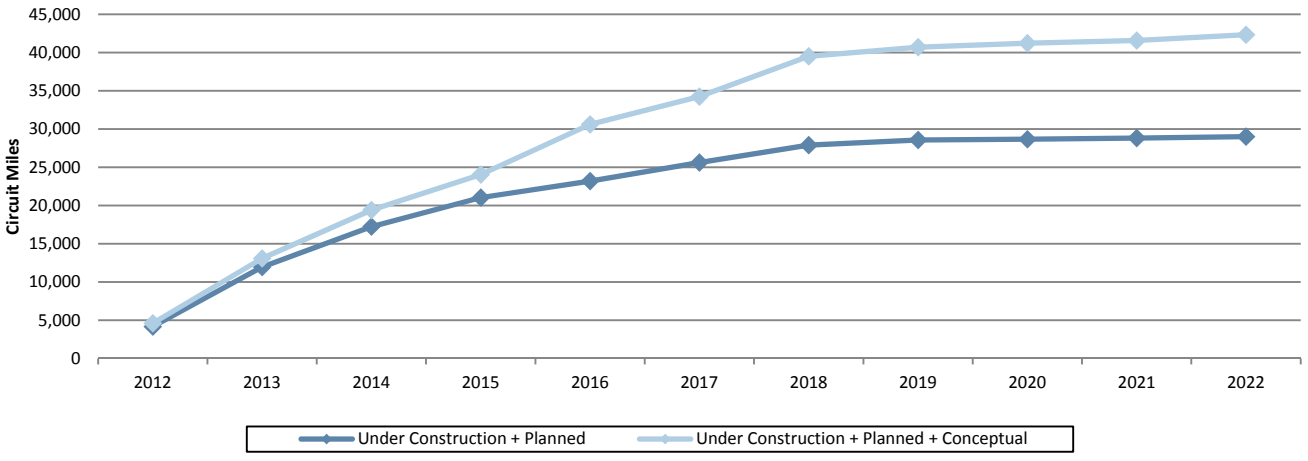
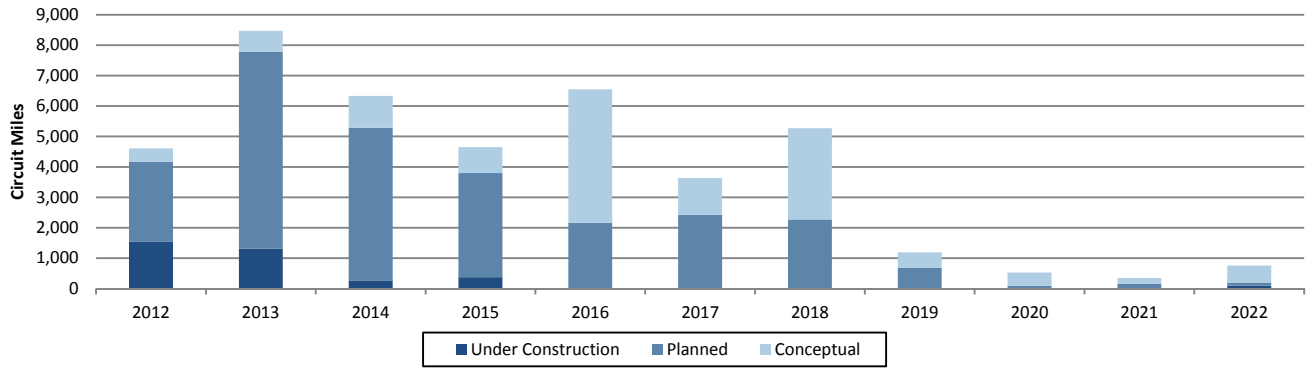


Figure 33: NERC-Wide Transmission Additions by Project Status per Year



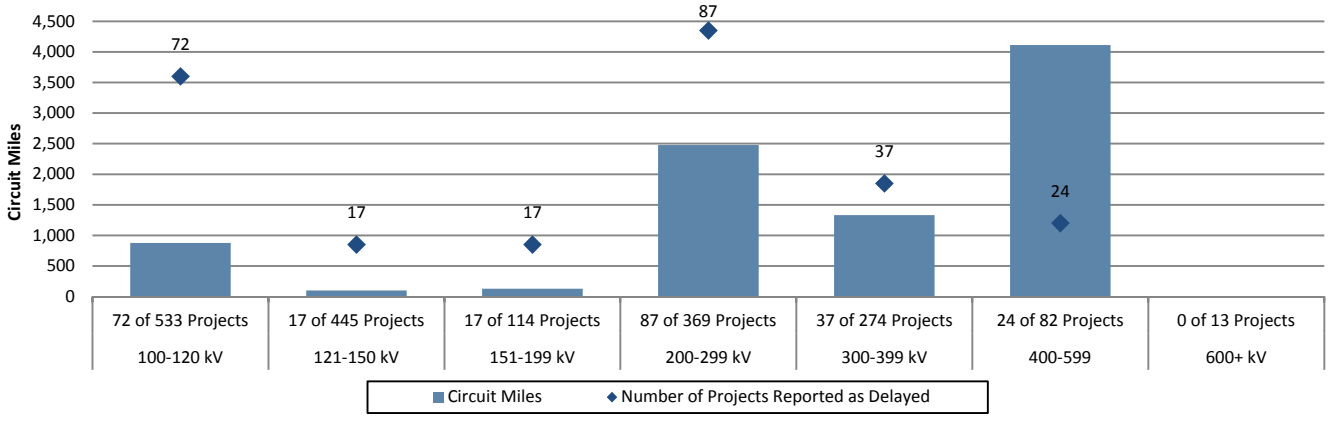
From 2012-2022, the industry has under construction and planned transmission facilities that will add approximately 29,600 circuit miles to the existing[91] North American transmission infrastructure.

NERC continues to monitor the progress of transmission projects across North America. While transmission planning is dynamic (i.e., project is needed one year, but can be deferred due to a change in demand forecasts), plans should reflect realistic expectations in order to reliably support system needs in the future.

Along with the status of transmission plans, NERC gathers information on key drivers that are delaying the construction of individual transmission line and infrastructure development projects. Deferrals based on reassessments of load growth have been the primary reason for delays of new transmission and upgrades of existing transmission infrastructure. Results from recent transmission studies in these areas show that some large transmission projects, such as the Potomac-Appalachian Transmission Highline (PATH) project in PJM, are no longer necessary to maintain grid reliability and have been put on hold.

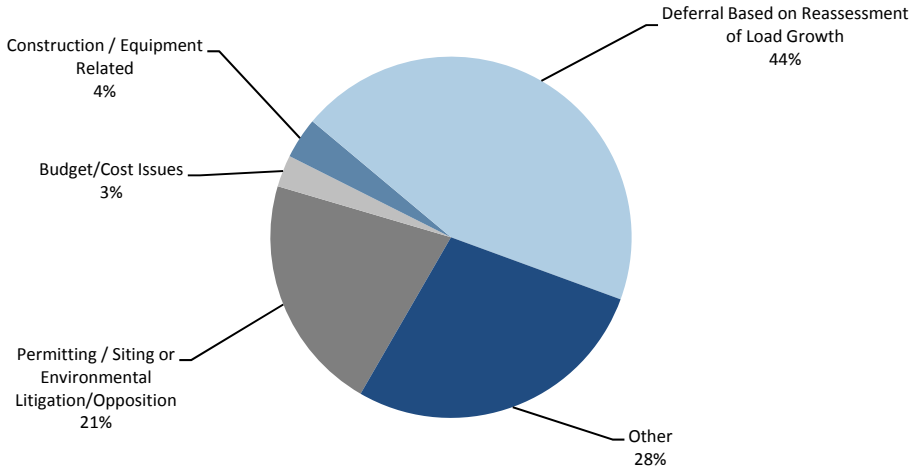
Across North America, 230 transmission projects consisting of almost 5,000 circuit miles are currently considered delayed or deferred.[92] A majority of the delays in transmission projects are observed at the 200-299 kV class (approximately 2,500 circuit miles). Additionally, 72 projects at the 100-199 kV class, totaling less than 900 circuit miles, are currently delayed or deferred. Because these lower voltage lines are typically built in less rural areas, siting and permitting issues may present more of a challenge. Permitting, siting, and other regulatory issues account for 21 percent of transmission project delays (Figure 34 and Figure 35).

Figure 34: Current Transmission Project Delays and Deferrals



[91] Existing circuit miles as reported for December 31, 2011.
[92] The total of circuit miles reported as delayed to NERC by assessment area is 4,915 miles.

Figure 35: Reasons for Transmission Project Delays and Deferrals



Transmission lines are the critical link between generation and bulk power system customers. As demand grows and generation is built in areas remote from the demand, more capacity on the transmission system is needed to meet demand. As more and more power is moved over transmission lines, congestion can have a significant impact on reliability. As these lines reach their capacity, for example, it is more difficult for them to make up the difference when neighboring lines are forced out of service. Under-investment in transmission puts additional strain on existing resources, which raises the risk of system disturbances, lengthens restoration time when outages do occur, and limits access to remote generation.

The benefits of more transmission are also far-reaching. New transmission can reduce installed capacity and reserve requirements, reduce losses, increase transfer capabilities, and provide diversification of renewable generation over a large geographical region.

Risk Assessment Summary

Impacted Assessment Area(s)	All Regions
Impact Type	Resource Adequacy - A constrained and limited transmission system could potentially affect resource deliverability and cause generator de-rates.
	Operating Reliability - Increased stress to transmission systems can cause a decrease in the performance of transmission facilities.
Magnitude of Impact	15,000 circuit miles Planned over next five years
	26,000 circuit miles Planned over next ten years
Likelihood of Impact	Increased delays could impede the industry's transmission plans
	Since less than 10 percent of all circuit miles are currently delayed or deferred, actual additions may not meet expectations.

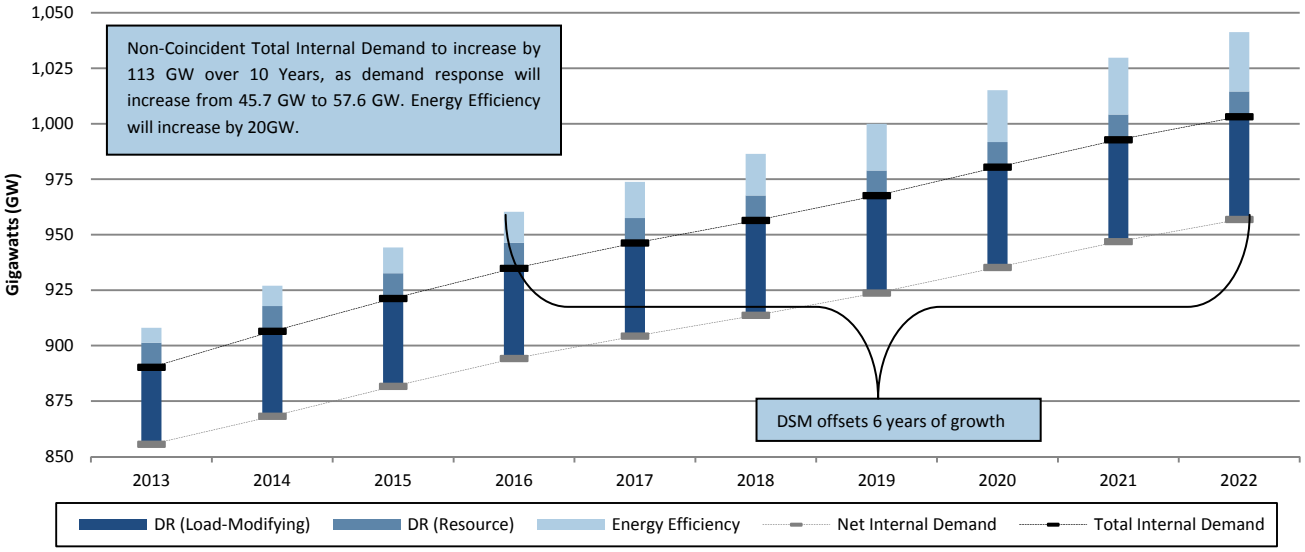
Recommendations

NERC	NERC should expand its understanding of projected transmission resource acquisition strategies being employed throughout North America. Therefore, categorization of transmission additions should be considered to fully appreciate transmission resource requirements. NERC should identify transmission assessment metrics to determine if future projects are sufficient to meet projected resource plans.
	NERC should continue to provide information and support to NERC stakeholders on the need for new transmission in North America.
Regulators	Regulators need to continue their support for additional transmission resources. Further, they should revise their existing processes to expedite the licensing of transmission projects needed to maintain reliability.

Increases in Demand-Side Management Help Offset Future Resource Needs

All areas are projecting at least some increased availability of DSM over the next 10 years to reduce peak demands, contributing either to the deferral of new generating capacity or improving operator flexibility in the day-ahead or real-time time periods. NERC-wide, DSM is projected to total roughly 80,000 MW by 2022 (or about 7 percent of the on-peak resource portfolio), offsetting approximately six years of peak demand growth (Figure 36).

Figure 36: Demand-Side Management Offsets Six Years of Peak Demand Growth

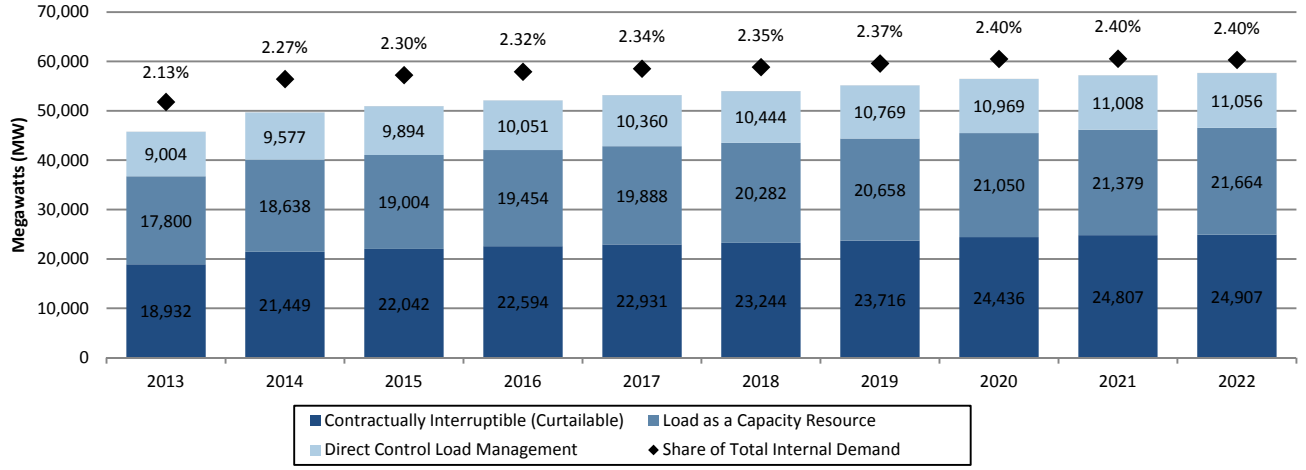


However, DSM is not an unlimited resource and may provide limited demand reductions during pre-specified time periods (generally during peak or adverse system conditions). Some Regions—such as ERCOT, FRCC, NPCC, and WECC—have been using DSM for many years, while others have less penetration. Historical performance data from these Regions may also provide a way to analyze the benefits from these resources.[93] The structure of DSM programs (e.g., performance requirements, measurement and verification applicability, and resource criteria) may be indicative of how well these programs perform when needed. The shared experiences and lessons learned from these high-penetration areas should benefit the North American BPS in providing more planning and operating flexibility.

In terms of DR (Dispatchable and Controllable), total expected capacity is anticipated to increase from approximately 46,000 MW to 59,000 MW by 2022. Year-over-year increases are projected to remain steady through the 10-year period, compared to previous years where projections would plateau after three or four years (Figure 37).

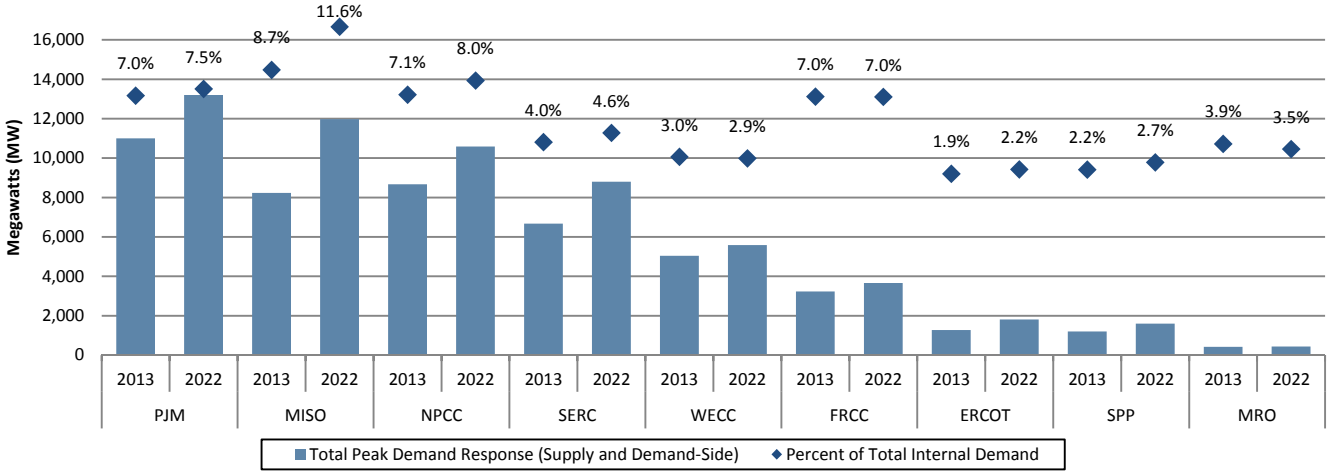
[93] NERC Demand Response Availability Data System (DADS) is collecting Demand Response performance data on a semi-annual basis. The goal of the DADS is to collect Demand Response enrollment and event information to measure its actual performance including its contribution to improved reliability. Ultimately, this analysis can provide industry with a basis for projecting contributions of dispatchable and non-dispatchable Demand Response supporting forecast adequacy and operational reliability. For more information, visit the DADS website at: http://www.nerc.com/page.php?cid=4|357.

Figure 37: NERC-Wide Dispatchable, Controllable Demand Response Increases Steadily over 10 Years



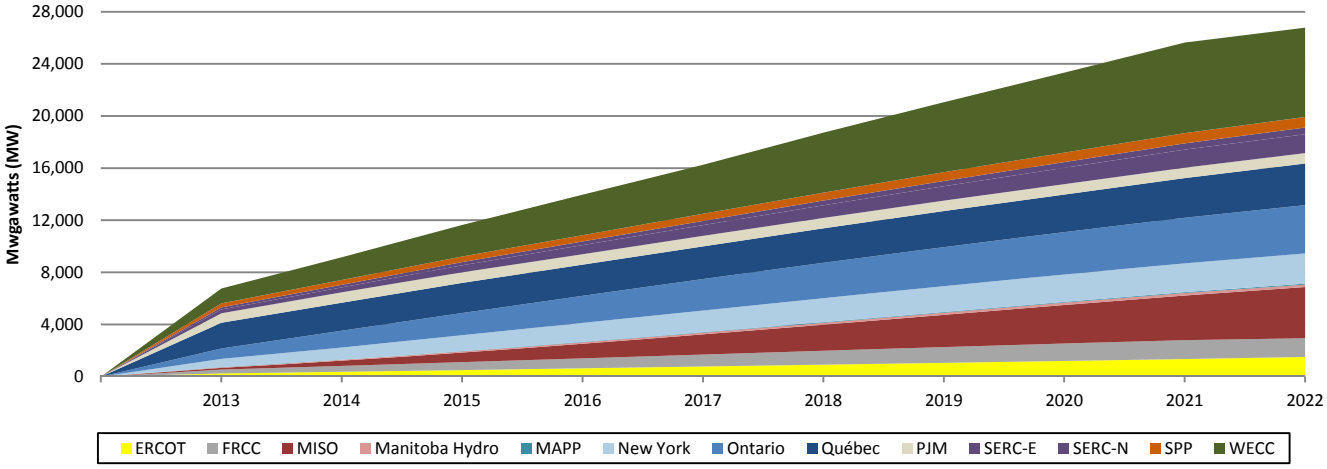
From an assessment area perspective, PJM, MISO, and NPCC administer the most DR and represent over half of the total DR NERC-wide. These relatively large demand response participation values represent about 8 percent of the Total Internal Demand for each of the areas, with MISO projected to increase to nearly 12 percent by 2022 (Figure 38).

Figure 38: NERC-Wide Dispatchable, Controllable Demand Response Increases over 10 Years



Through EE and Conservation, permanent replacement or more efficient operation of electrical devices results in demand reductions across all hours of use, rather than event-driven, targeted demand reductions. In the next 10 years, EE across all NERC Regions is expected to reduce demand by over 19,000 MW during the NERC-wide summer peak. While most assessment areas show increases compared to last year, significant EE is projected in WECC, NPCC, and MISO. As a result of implementing EE programs, the electric industry in North America has deferred new generating capacity by approximately two years. The ability to implement EE programs relatively quickly provides the industry with another short-term solution to help defer any anticipated capacity shortfalls. Successful integration of EE into resource planning requires close coordination between those responsible for EE and those in bulk system planning to ensure appropriate capacity values are estimated while meeting reliability objectives (Figure 39).

Figure 39: Growth in Energy Efficiency Supports Deferral of Capacity Needs[94]



The type of EE programs (industrial, commercial, and residential) influence the total capacity (MW) reduction depending on the time of day and desired reduction. Load forecasting is a critical component to understanding the overall peak reduction observed or projected. Tracking and validating EE programs is vital to increasing the accuracy of forecasts. In some areas, experience with these demand-side resources has improved. For example, in ISO-NE demand-side resources can participate just like traditional generation resources in the Forward Capacity Market.[95] The ability to demonstrate effective performance of these resources illustrates the confidence exhibited by system planners and operators in using demand-side resources to fulfill capacity obligations and maintain the same level of reliability.

Potential drivers for the continued expansion of EE programs in the future are Renewable Portfolio Standards (RPS), which commonly include provisions for energy-reducing actions to account for a portion of the renewable resource requirement (generally no more than 5 percent of total energy use). Other policy drivers include the American Recovery and Reinvestment Act of 2009,[96] which includes provisions for significant investments in energy and climate-related initiatives; the American Clean Energy and Security Bill of 2009,[97] which established credits for reduced carbon emissions; the Climate Change Plan for Canada;[98] and several regional, state, and provincial initiatives.[99]

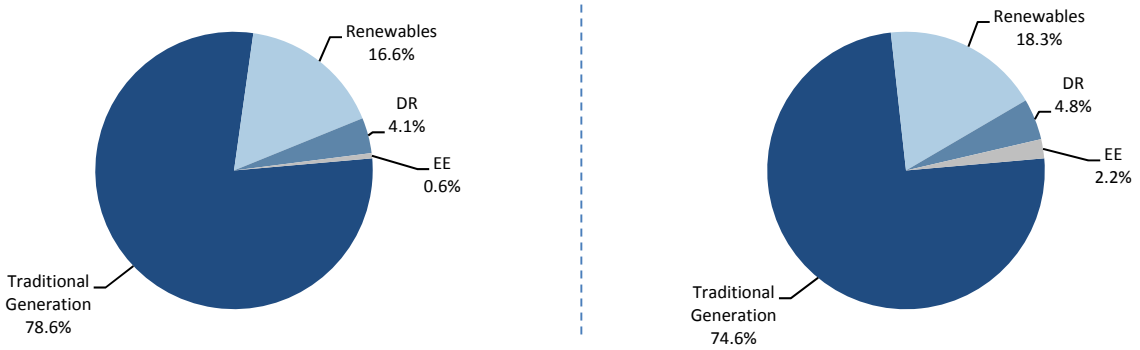
Uncertainty exists not only in how much peak demand reduction will actually be realized at the particular time when DR is needed and deployed, but also in the long-term sustainability of these resources.[100] Unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of DR involve greater forecasting uncertainty. Because participation in DR programs is highly dependent on a number of economic variables and incentives, it is challenging to forecast how much DR will be available beyond three or four years.[101]

As DSM is increasingly deployed in response to climate change initiatives or mandates, it will become a larger portion of the overall resource portfolio. During the next decade, DR will increase to approximately 4.8 percent of the total resource mix, and EE will account for 2.2 percent. Climate change initiatives at the state/provincial level, along with consumer-led efforts to reduce energy consumption, will broaden the size and scope of DSM programs. Both EE and DR can make significant

[94] NPCC-New England did not provide separate EE data.
[95] http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/cap_mkt/index.html
[96] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.txt.pdf
[97] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h2454pcs.txt.pdf
[98] http://dsp-psd.pwgsc.gc.ca/Collection/En56-183-2002E.pdf
[99] Reliability Impacts of Climate Change Initiatives report: http://www.nerc.com/files/RICCI_2010.pdf
[100] Refer to the *2010 Long-Term Reliability Assessment*, Emerging Reliability Issues: Uncertainty of Sustained Participation in Demand Response Programs section http://www.nerc.com/files/2010_LTRA_v2-.pdf
[101] In most cases, actual forecasting of Demand Response is not performed, per se. Rather, projections are based on resource requirements and the amount of capacity contracted during a given commitment period--usually between one and three years.

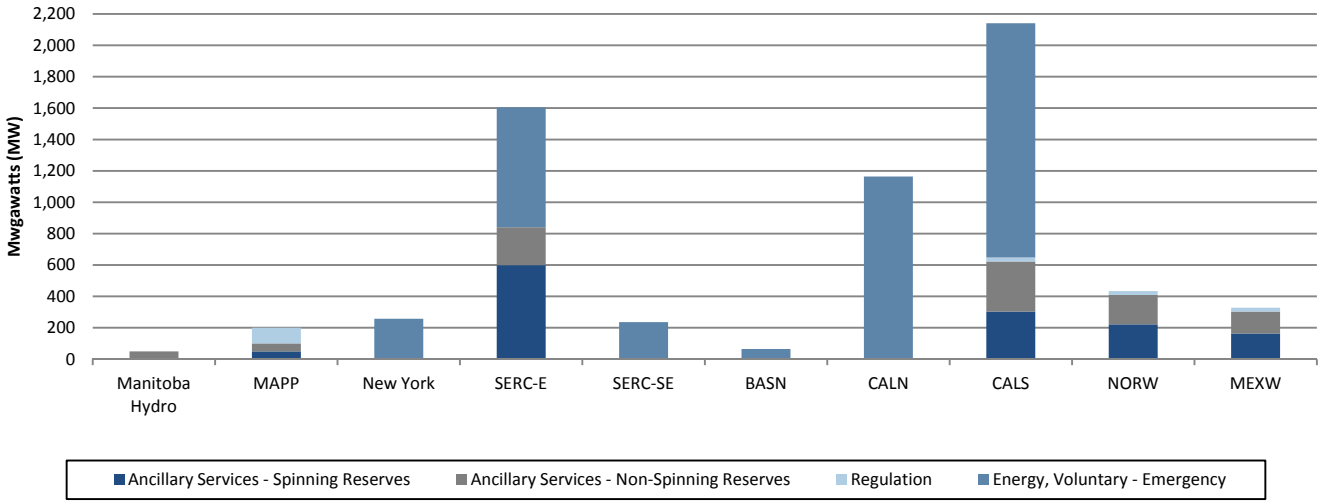
contributions to a reduction in greenhouse gases, with EE providing ongoing benefits and DR driving energy use to time periods when lower or non-carbon-emitting resources are available. DR can also enable the integration of renewable resources by supporting a variety of new operating characteristics associated with variable resources. Therefore, broader industry experience is needed as the certainty, locality, and characteristics of DSM become increasingly important to reliability of the BPS (Figure 40).

Figure 40: Growth in Energy Efficiency Supports Deferral of Resource Needs in 2013 (Left) and 2022 (Right)



While many similarities exist between DR and generating capacity, key differences in terms of availability, performance, and sustainability may appear as a given system becomes more stressed. Less-understood attributes of these resources, such as response fatigue[102] or economic-based participation rates, must be carefully monitored to ensure they do not pose reliability issues in the future. DR is increasingly being used to balance system load and to relieve resource adequacy and transmission reliability issues. Decreased or insufficient participation could lead to operational challenges where peak demand cannot be met by current generation or transmission resources. In 2013, just over 7,000 MW of DR NERC-wide is projected to support operational and emergency flexibility through the provision of ancillary services. There is virtually no increase in these values through the 10-year period (Figure 41).

Figure 41: Demand Response Used for Ancillary Services and Emergencies Increases Operator Flexibility[103]



[102] Response fatigue is a characteristic of demand resources that initially participate in Demand-Side Management programs because of the financial incentives. Once the electric supply to their equipment has actually been interrupted a number of times, the inconvenience outweighs the cost savings and the resource may potentially withdraw from the programs.

[103] Assessment areas not shown did not report any Demand Response used for Ancillary Services to be used during the peak.

The Reliability Assessments Subcommittee identified the following assumptions while reviewing this concern for consideration as an emerging reliability issue:

- DR participation plateaus in the long term
- Potential increase in frequency of use within the short term
- Character differences in traditional generation resources versus DR resources

The increased penetration of DR raises operational challenges in numerous areas of day-to-day operation of the BPS. Should DR be unable to deliver the required reduction in demand as committed, real-time operations may be challenged to ensure that adequate resources are available (contingency reserve) and that transmission facilities are operated within their defined limits to maintain BPS reliability.

Any analysis of DR fatigue should also be in effort to determine whether measure type. Moreover, load reduction versus customer-owned generation or temperature-sensitive load versus non-temperature-sensitive load (e.g., HVAC versus lighting, etc.) plays a significant role in the issue of DR fatigue.

DR fatigue issues also concern baseline estimation. The difference between the baseline and the resource's actual load is commonly used to determine the performance of a DR resource. However, if a DR resource is both responding to high-energy prices *and* participating in a capacity market (jointly enrolled participation), the resource will not be available to reduce load, should Emergency Operating Procedures (EOPs) be invoked at a time when the DR resource is actively reducing load for the price-responsive program. If the DR resource is already reducing load when EOPs are called, the amount of load reduction available from those DR resources could actually be lower than their capacity market obligation. This is especially an issue if the system operator is not aware that the load relief was unavailable. Additionally, if a DR resource is responding often to price signals, it becomes unclear how the baseline should be estimated. Establishing a baseline method for DR resources gives the system operator an accurate, real-time picture of available DR.

In addition to baseline estimation issues, analysis should include data quality and meter accuracy issues that have been encountered in estimating actual DR reductions. Telemeter data provides effective and reliable metering solutions that provide near real-time meter information in order to assess actual performance. Follow-on action can then be taken by the system operator once the initial dispatch signals were given. System operators must know how much DR actually responded. Further, system operators may be able to track or identify actions by DR resources through feeder, substation, or pricing node data.

These issues become even more important as system operators begin to use DR more to control transmission constraints, provide ancillary services, and manage contingency reserves. Program-specific details to the maximum interruption frequency must be fully considered. For example, several DR programs limit the amount of times service can be interrupted from the customer within a given time period (e.g., per day, month, or season). Where these limits exist, reductions in peak demand may not be obtainable by the system operator if extreme weather conditions were to persist for a prolonged period of time during the peak season. More experience and data analysis associated with DR performance will be required to establish the long-term availability, effectiveness, and customer acceptance of these programs.

The trend of increased use of DR programs to meet projected peak demands gives system planners the confidence that the trend will continue in the future. If DR programs fail to deliver committed load shedding, additional generation resources and transmission facilities may need to be planned and constructed to deal with an unplanned contingency response. Additionally, expected transmission and generation resources may not be online due to scheduled or unscheduled maintenance, further complicating the issue if DR programs are planned as fixed reductions in load.

These results and findings of any analysis on DR fatigue should assist system planners in developing guidelines for treatment of DR resources within both short and long-term planning studies. The assumptions regarding performance and availability of DR need to be developed and incorporated into various types of traditional transmission planning studies such as steady state, short circuit, thermal, and voltage analyses.

Risk Assessment Summary	
Impacted Assessment Area(s)	PJM
	MISO
	NPCC
	SERC
	WECC
Impact Type	Resource Adequacy - Unavailability and non-performance of expected DR during peak periods can contribute to a capacity shortage
	Operating Reliability - DR can have unforeseen impacts to system stability and voltage support if not sufficiently modeled
Magnitude of Impact	80 GW of DSM (DR and EE) are projected to be available by 2022
	DR projected up to 12 percent of peak demand
Likelihood of Impact	The likelihood of an event that impacts reliability is greatly reduced if proper planning processes, operational procedures, and operator training have been implemented
	Increasing operator experience with demand response characteristics and behaviors should enhance system operators' ability to manage unpredicted events

Recommendations	
NERC	NERC should continue to monitor the Demand Response Availability Data System (DADS) data to identify availability and performance trends that may indicate potential planning risks.
	NERC should determine whether requirements or guidelines are needed to support demand response planning and operations—specifically, demand response that is relied on to meet reliability targets and provide ancillary services.

Progress Since 2011

NERC identified six key findings in the *2011 Long-Term Reliability Assessment*[104] that could affect long-term reliability, unless the electric industry took action to address and mitigate the impacts. The 2011 key findings were based on observations and analyses of supply and demand projections submitted by the Regional Entities, a NERC staff independent assessment, and other stakeholder input and comments.

The magnitude of these issues necessitates complex planning and effective strategies whose effects may not be realized for several years. While significant progress has been made since last year, continued action is still needed on all of the issues identified in last year's report to ensure a reliable bulk power system for the future. NERC continues to monitor and assess these issues based on industry progress through its annual reliability assessments, as well as through any special reliability assessments that may be needed as determined by the NERC Planning Committee.

While significant progress has been made over the past year for many of these issues, others have not yet been resolved, and continue to exacerbate power system planning and operations.

2011 Key Finding #1: A decrease in Future and Conceptual generation resources is projected reduce Planning Reserve Margins in some areas—resource adequacy in ERCOT shows signs of concern; however, most areas appear to have adequate resource plans to meet projected peak demands.

Developments in 2012:

- Overall, most areas are projecting decreased Planning Reserve Margins compared to last year, but still at levels above the NERC Reference Margin Levels.
- Projected resource adequacy concerns in ERCOT have worsened, as targets are not projected to be met by next year.
- Decreased Reserve Margin concerns in only some areas remain in 2012 and are a key finding in this report. This is due to shorter lead times for bringing on-line natural gas and renewable generation capacity, as well as the growth in demand response. All of these drivers contribute to future uncertainty as system planners can defer large capacity development projects for longer periods of time, which allows decisions to be made at a later time without an impact to reliability.
- In 2012, NERC issued a Pilot Probabilistic Assessment to determine if added value could be obtained from enhanced resource adequacy metrics. In September, the Planning Committee approved the implementation of a continent-wide biannual assessment of probabilistic indices.

2011 Key Finding #2: Existing and proposed environmental regulations in the United States may significantly affect bulk power system reliability, depending on the scope and timing of the rule implementation and the mechanisms in place to preserve reliability.

Developments in 2012:

- On December 21, 2011, the Environmental Protection Agency (EPA) released the Mercury and Air Toxics final rule pursuant to its authority under Section 112 of the Clean Air Act. Enhanced flexibility for generator compliance was included by allowing an additional year for modifications and provisions for extension requests. The proactive engagement among system planners, EPA, DOE and FERC has significantly aided the implementation of solutions to address the potential impacts associated with expected retirements and retrofits. Most importantly, should a reliability concern arise, additional safeguards are in place to ensure the continued operation of a given generator deemed critical to system reliability.[105] However, significant concerns still remain in the industry's efforts to coordinate a large environmental retrofit effort, as well as constructing the necessary transmission upgrades as a result of accommodating a shifting resource mix.

[104] *2011 Long-Term Reliability Assessment:* http://www.nerc.com/files/2011%20LTRA_Final.pdf

[105] See Key Findings section for more information on tools in place to ensure reliability.

- On August 21, 2012, the D.C. Circuit Court vacated the Cross-State Air Pollution Rule (CSAPR),[106] which had originally required 23 states to reduce annual SO_2 and NO_X emissions. Since then, the EPA has appealed for full court review.
- On June 27, 2012, the EPA revised an agreement that now calls for the agency to take final action by June 27, 2013, to implement cooling-water rules for existing power plants under Section 316(b) of the Clean Water Act. The extension will allow the federal agency time to review public comments received on controls required to protect aquatic life and on a survey to help determine benefits of the rule.

2011 Key Finding #3: The growing dependence on natural gas as a primary fuel source of on-peak capacity must be considered in planning. Operational measures must be in place to minimize interdependency risks, particularly during off-peak periods as more gas-fired generation is expected to provide base-load functions.

Developments in 2012:

- NERC continues to assess the reliability of the BPS through periodic and special reliability assessments. The NERC Phase II effort on gas dependency targets dependency risks by determining the different vulnerabilities that can affect BPS reliability, identifying ways that could minimize those vulnerabilities, and identifying approaches where coordinated inter-industry activities could provide enhanced system reliability.
- In 2012, NERC issued a lesson learned document on gas and electric interdependencies as a result of key findings from the *Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011*.
- During August of 2012, FERC held a series of five regional conferences, which addressed local situations directly with electric grid operators, utilities, power generators, natural gas pipeline operators, natural gas producers, and natural gas distributors.
- The NERC Phase II effort on gas dependency targets dependency issues by determining the different vulnerabilities that can affect BPS reliability, identifying ways that could minimize those vulnerabilities, and identifying approaches where coordinated inter-industry activities could provide enhanced system reliability. The report is scheduled to be released by the end of 2012.

2011 Key Finding #4: Significant growth in wind and solar generation continues to be projected and surpasses the NERC-wide on-peak capacity forecasts of all other types of generations. Tools, training, and transmission remain key to successful planning and operations.

Developments in 2012:

- NERC will issue three special reliability assessments on accommodating high levels of variable generation, which include reports and recommendations for interconnection requirements, system operator communications, and probabilistic methods for resource adequacy.
- NERC will also issue a joint report with the California Independent System Operator (CAISO), which focuses on challenges and solutions aimed at the area's growing resource mix of variable generation.

2011 Key Finding #5: Significant increases in Demand-Side Management continue to offset future resource needs, while dispatchable and controllable demand response can expand flexibility for operators.

Developments in 2012:

- Compared to last year's projections, planners anticipate significant growth in Demand-Side Management.
- Smart meter integration in the residential sector, increased retail and wholesale demand response programs, and state-sponsored initiatives have further enabled demand-side resources from participating in economic and reliability-based programs.

[106] The CSAPR was initially designed to replace EPA's 2005 Clean Air Interstate Rule (CAIR). A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement Clean Air Act requirements concerning the transport of air pollution across state boundaries. This action responds to the court's concerns. For additional information see the EPA website http://www.epa.gov/airtransport/.

2011 Key Finding #6: Transmission growth as a result of increased plans for integrating and delivering new resources (i.e., renewables); constructed transmission is on pace with projections.

Developments in 2012:

- Numerous transmission projects are planned and designed specifically for the integration of new renewable generation.
- In recent years, higher-than-average plans have been met with the construction of significant transmission.
- Five years ago, transmission was constructed at a rate of about 1,000 circuit miles per year. In the last five years, more than 2,300 circuit miles came into service each year, which more than doubled actual builds in the previous five years. The current plans further increase that rate to 3,600 miles per year over the next five years.

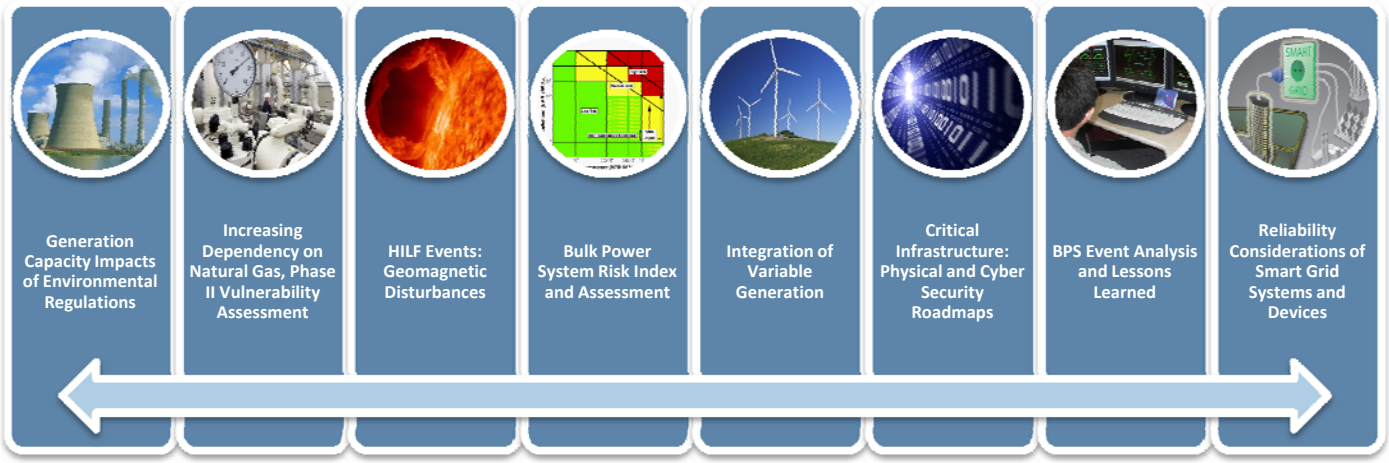
Emerging Reliability Issues in Focus

The NERC Reliability Assessment and Performance Analysis (RAPA) program reviews, assesses, and reports on the overall electric reliability of the interconnected bulk power system in North America. As part of this assessment, the program identifies and analyzes the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes.

Each year, the NERC *Long-Term Reliability Assessment* forms the basis for the NERC reference case. This reference case incorporates known policy and regulation changes expected to take effect throughout the 10-year timeframe, assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior. A set of scenarios can be developed from risk assessment of emerging reliability issues. These scenarios can then be compared to the reference case to measure and identify any significant changes to the BPS that may be required to maintain reliability.

For this reason, NERC investigated each of these emerging reliability issues through structured technical committees and leveraged the expertise of the electric industry's broad knowledge base. Over the next decade, the electric industry will face a number of significant emerging reliability issues. The confluence of these issues will drive a transformational change for the industry, potentially resulting in a dramatically different resource mix with significantly increased reliance on natural gas and renewable generation, a need for enhanced and sophisticated modeling, a new risk and probabilistic framework built to address reliability challenges, and growing critical infrastructure and protection concerns—both physical and cyber. Many of these change elements are critically interdependent, and industry action must be closely coordinated to ensure continued reliability. As a result, numerous NERC activities are currently ongoing, which exemplifies the industry's commitment to understand, resolve, and make recommendations that support enhancing future reliability (Figure 42).

Figure 42: NERC Actions and Activities to Address Emerging Reliability Issues



Since 2007, the Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee (PC) has identified a number of issues of strategic importance to the industry and surveyed industry participants to rank these issues based on their probability of occurrence and their impact to the reliable operation on the BPS over both the one-to-five-year and six-to-ten-year time frame. A number of recommendations based on emerging reliability issues identified in the *LTRA* were developed to support long-term reliability risks and challenges; however, not all have been fully addressed.

In August 2012, the NERC Board of Trustees approved the charter and start-up of the Reliability Issues Steering Committee (RISC), which is an advisory committee to the board that provides front-end, high-level leadership, prioritization, and accountability for issues of strategic importance to BPS reliability. The RISC assists the Board, NERC standing committees, NERC staff, regulators, Regional Entities, and industry stakeholders in establishing a common understanding of the scope, priority, and goals for the development of solutions to address these issues. In some cases, that includes recommending

reliability solutions other than the development of new or revised standards and offering high-level stakeholder leadership engagement and input on issues that enter the standards process. The recommendations will improve efficiency of Reliability Standards development, engage high-level stakeholder leadership, and promote reliability excellence.[107]

The issues surveyed by the RAS in 2012, as well as other identified reliability issues from the *2007-2011 Long-Term Reliability Assessments* will be submitted on behalf of NERC staff, the PC, and the industry for review, analysis, and prioritization of action by the RISC.

2012 Emerging Reliability Issues

For the *2012 Long-Term Reliability Assessment*, NERC gathered emerging issues previously identified in other assessments as well as issues identified and assessed in a survey submitted to the technical committees and based on RAS identification. For many reasons, it is difficult for NERC to evaluate every emerging issue that can potentially impact reliability in the future—including unforeseen and unpredictable events. Each year the RAS identifies a set of issues that are of particular concern. RAS identified eight issues for use in a risk assessment survey. A risk assessment was performed on these issues and detailed with additional information provided in Appendix V. The voting members of the Planning Committee, Operating Committee, and Members Representative Committee provided their input on risk, which was defined as determining likelihood of occurrence and consequence. They categorized each issue as high-impact, medium-impact, or low-impact to reliability and identified other characteristics of the impact.

Across North America, several issues affecting BPS reliability are regional. Because some Regions are more vulnerable to certain risks than others, the possibility of a risk impacting the power system can vary. Looking at regionally aggregated overall likelihood can be misleading as the possibility of an impact for one given area can be very high, but for another it can be very low. By aggregating these two areas, the overall likelihood can significantly mask impacts that may be regionally focused.

Two fundamental and measurable characteristics of BPS reliability form the foundation of the concepts described in this document—*resource adequacy*[108] and *operating reliability*[109] (or system security). Each issue has the potential to impact these two characteristics differently; therefore, the impacts to system reliability can be different and must be well-understood. While not considered in the figure below, integrating the likelihood of occurrence for each impact can provide a greater understanding of expected reliability consequences.

On the impact side, a greater understanding of expected reliability consequences can be easily assessed. For example, signifiacnt generator retirements have a greater impact on resource adequacy compared to operating reliability. Conversely, transmission facility-related impacts, such as geomagnetic disturbances and misoperation of Special Protection Systems (SPS), have a greater impact on operating reliability, as these issues have a direct impact to system stability and the performance of the transmission system under stressed conditions.

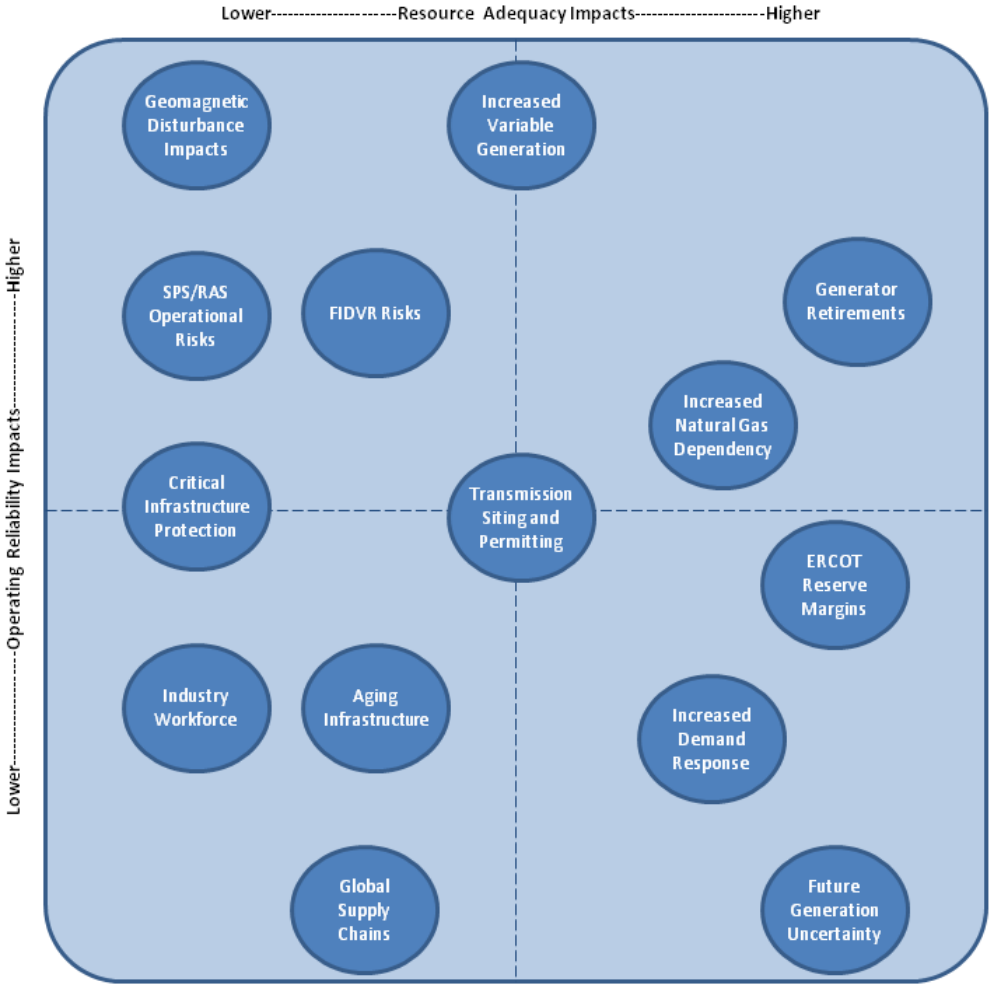
The results in the figure below are the product of combined industry surveys on emerging reliability issues, key findings from this report, engineering judgment, and prior independent assessments released by NERC (Figure 43).

[107] RISC Website: http://www.nerc.com/page.php?cid=1|117|428.

[108] Defined as the ability of the bulk power 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.

[109] Defined as the ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from credible contingencies.

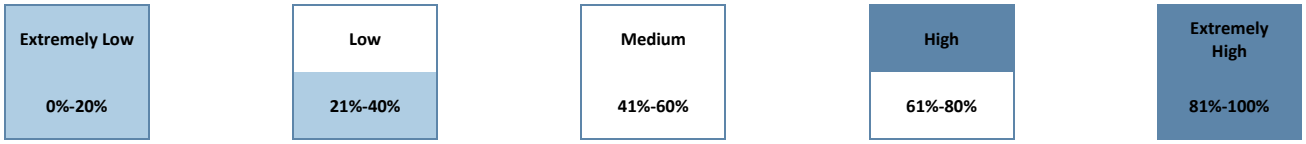
Figure 43: Future Reliability Challenges and Emerging Issues as a Function of Resource Adequacy versus Operating Reliability Impacts



In order to minimize these risks, the electric power industry must understand what the impact will be. With resource adequacy impacts, the ability of the BPS to supply the aggregate electrical demand and energy requirements is compromised. While shedding firm load is a likely impact, system operators should take controlled actions or procedures to maintain a continual balance between supply and demand. When supply is insufficient to meet all the demand, rotating outages or controlled interruption of customer demand is needed to maintain a balance with available supplies while maintaining the overall reliability of the interconnected system.

All other system disturbances that result in the unplanned or uncontrolled interruption of customer demand, regardless of cause are considered as operating reliability impacts. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as cascading outages—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 exposed area. The outage in 1965 and 2003 in the Northeast, as well as the most recent 2011 event in the Southwest, were uncontrolled cascading outages.

Emerging Issues Risk Impact Scale



Emerging Reliability Issues, Impact, and Risk Type

Reliability Issue	Onset Time	Impact Type	Key Finding	Associated Risks	Impact to Resource Adequacy	Impact to Real-Time Operations	Impact to Long-Term Planning
Significant Generator Retirements and Environmental Control Retrofit Outages	1-4 years	Resource Adequacy Real-Time Operations Long-Term Planning	• 65 GW of Retirements Projected • 44 GW confirmed at the time of publication	• Insufficient capacity to meet demand • Less flexibility to meet higher than forecasted demand	High	High	High
Accommodating Variable Resources in System Operations	Occurring and Increasing	Real -Time Operations Long-Term Planning	• 21 GW of Planned variable on-peak capacity added by 2022 • 46 GW of Conceptual variable on-peak capacity added by 2022	• Unplanned system contingencies could develop • Insufficient capacity to meet demand • Real and reactive power system mismatches could develop		High	High
Increased Dependency on Natural Gas	Occurring and Increasing	Resource Adequacy Real-Time Operations Long-Term Planning	• Potential impacts to long-term reliability, operational planning, and real-time operations	• Committed capacity unavailable for dispatch when needed • Insufficient planning of fuel contingencies and mitigation • Potential for wide-spread common-mode outages	High	High	High
Geomagnetic Disturbance Impacts to System Operations and Communications	Any	Real-Time Operations Long-Term Planning	Potential impacts to system operations and equipment Assessments underway to determine impact severity	• Unplanned system contingencies could develop • Solar Storm Forecast Warning • Frequency of coronal mass ejections			
Transmission Siting and Permitting	Occurring	Long-Term Planning	30,000 miles of transmission under construction + planned to be added from 2012-2022	• Capacity unable to reach demand • Unplanned system contingencies could develop without transmission reinforcements		High	High
Potential Operational Risks Associated with Interaction of Special Protection Schemes/Remedial Action Schemes	Occurring	Real-Time Operations	Special Protection Schemes a leading cause of 2011 Pacific Southwest Outage	• Unforeseen operational impacts with increased interaction of Special Protection System /Remedial Action Scheme		High	
Global Supply Chains and Fuel Reliability	Any	Resource Adequacy Real-Time Operations	Political Instability in countries supplying critical energy components	• Loss of capacity due to loss of fuel • Potential for wide-spread common-mode outages			
Assessment of Fault-Induced Delayed Voltage Recovery (FIDVR) Simulation	Any	Real-Time Operations	Planning Coordinators should study the impacts from FIDVR-related events	• System contingencies could develop that have not been fully analyzed and evaluated	Low		
Coordinated Cyber / Physical Attacks on Critical Infrastructure	Occurring	Real-Time Operations	Potential impacts to system operations and equipment	• Unplanned system contingencies could develop	Low		
Electricity Industry Workforce	Occurring	Long-Term Planning	Upcoming retirements of large numbers of veteran industry planners, operators, trades workers	• Reduction in experienced industry resources and knowledge • Insufficient knowledge transfer efforts	Low	Low	Low
Aging Infrastructure	Occurring	Real-Time Operations Long-Term Planning	Infrastructure installed in the 1960s and 1970s (and in some cases earlier) is reaching the end of its projected lifecycle.	• Infrastructure installed in the 1970s is reaching the end of its projected lifecycle.	Low		Low

Emerging Reliability Issue Summaries

Selected emerging reliability issues are summarized below. Additional detail is provided in Appendix V.

Significant Generator Retirements and Environmental Control Retrofit Outages

Largely due to the combination of low natural gas prices and environmental regulations, a significant amount of generation is expected to retire over the next four years. Overall, generation retirements need to be evaluated and analyzed in an integrated fashion. While the high degree of uncertainty surrounding retirement decisions continues to be exceedingly difficult, power system planners must continue not only to study the effects of individual generator impacts, but also recognize the cumulative impacts of multiple generator retirements.

In the United States, several regulations that directly affect the electric industry are either final or in the process of being proposed by the U.S. Environmental Protection Agency (EPA). The most significant proposed EPA rules have been in development for over 10 years and are currently undergoing court-ordered revisions that must be implemented within mandatory time frames. A significant retrofit effort is expected over the next 10 years in order to comply with federal and state-level environmental regulations. Environmental controls are expected to be put in place to meet newly finalized Clean Air Act rules by the end of 2016. While federal water rules (i.e., Section 316 (b) of the Clean Water Act: Cooling Water Intake Structures) may also affect retirements and outage scheduling, regulations have not yet been finalized.

Accommodating Variable Resources in System Operations

The expected significant increase in variable generation additions to the BPS will increase the amount of uncertainty that a system operator must factor into operating decisions. To manage this increased uncertainty, the system operator must have access to advanced variable generation forecasting techniques and have access to sufficient flexible resources to mitigate the added variability and uncertainty associated with the large-scale integration of variable generation. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures, and tools must be enhanced to assist operators in maintaining BPS reliability. Improved operating practices, procedures and tools are critical in order to integrate variable generation into the power system, as well as improve the control performance and reliability characteristics of the power system. System resources supporting reliability, such as flexible generation and responsive load, are finite. Operating practices, procedures, and tools that maximize the effective use of limited responsive resources improve reliability and facilitate variable generation integration.

Increased Dependency on Natural Gas

The majority of new North American generating capacity projected for the next 10 years will rely on natural gas as its primary fuel. With a shift to unconventional gas production in North America, the potential to increase availability of supply makes gas-fired generation a premier choice for new generating capacity in the future, overtaking and replacing coal-fired capacity. However, increased dependence on natural gas for generating capacity can amplify the BPS's exposure to interruptions in natural gas fuel supply and delivery. Mitigating strategies—such as storage, firm fuel contracting, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, nearby plants using other fuels, or additional transmission lines from other areas—can contribute to managing this risk.

In the future, the electric sector will be responsible for most of the growth in natural gas demand. The combination of this growth in gas demand within the electric sector and its changing status among the gas-consuming sectors has significantly increased the interdependences of the two industries and increased the focus on the interface between them. A key element of this interface focus is the need for increased coordination between the two industries, particularly at a regional level.

Geomagnetic Disturbance Impacts to System Operations and Communications

In February 2012, NERC reported that the most likely result from a strong geomagnetic disturbance (GMD) is voltage collapse. NERC also found that particularly large geomagnetically induced current (GIC) flows can result in transformer damage and may ultimately result in the failure of some transformers. The risk of the introduction of GIC into the BPS may

be at greater for Regions that are situated in the northern latitudes and have high ground conductivity. Depending on the duration and severity of the occurrence, GIC can impact real-time operations and equipment. Real-time operations could be impacted when reactive demands increase as transformers experience thermal heating from geomagnetically induced currents. If reactive demands and geomagnetic currents are not properly monitored, situations could develop in which an uncontrolled cascade of the BPS due to the introduction of geomagnetically induced currents ultimately results in voltage collapse.

The industry is well-equipped to face a small number of transformer failures; however, due to the concerns about an extreme GMD event causing a larger-than-expected number of failures, it is imperative that the nature of the reliability risk be quantified before a corrective action is developed. Therefore, the industry should consider vulnerability assessments, equipment testing, operational procedure enhancements, and appropriate measures for grid and facility hardening to address potential impacts.

Transmission Siting and Permitting

Siting difficulties have always been an issue for utilities. However, with increasing plans for new transmission, ensuring transmission can sufficiently be built within a specified time period has increased the importance of this issue. Siting of new bulk power transmission lines brings with it unique challenges due to the high visibility, their span through multiple states and provinces, and, potentially, the amount of coordination required among multiple regulating agencies and authorities. Lack of consistent and agreed-upon cost allocation approaches (specific to transmission construction), coupled with public opposition due to land use and property valuation concerns, have, at times, have resulted in long delays in transmission construction. When construction is delayed, special operating procedures to maintain BPS reliability may be needed.

Potential Operational Risks Associated with Interaction of Special Protection System / Remedial Action Scheme

Special Protection Systems (SPS) and Remedial Action Schemes represent a planning and operation alternative to the addition of new transmission facilities. Although an SPS is less costly and faster to install than building new facilities, it has the risk of potentially failing to operate and adds planning and operational complexity. System operators need to be aware of the potential impacts associated with an SPS or remedial action scheme. The possible lack of modeling requirements and real-time analysis capabilities of an SPS/RAS reduces the planners' and operators' capability to evaluate the reliability impact that these tools bring into the system. These tools also had important implications during the Southwest outage in September 2011.[110] Accordingly, the objective of this emerging issue is to: (1) evaluate historical and future trends in SPS identification and deployment; (2) identify limitations of SPS deployment and proliferation; (3) propose a framework for assessing SPS risks; and (4) propose modeling and assessment improvements.

Global Supply Chains and Fuel Reliability

Reliance on global supply chains for fuel and other products used to generate electricity must be managed with a common goal of reducing the risk of a prolonged disruption. The electric industry has a reputation for being risk averse; therefore, discrete or short disruptions in the supply chain are less likely to cause great issue—operational and strategic plans are often put in place to deal with a low-occurrence event. However, large and prolonged supply chain impacts could disrupt the ability for a given power plant, or group of power plants, to produce electricity and, therefore, cause significant reliability concerns.

Of specific concern are global supply chains that are made up of weak chains (e.g., political uncertainty and instability, war-stricken states, weak ties to North American foreign affairs). Currently, there are two known potential supply chains of specific concern to the electric power industry: scarcity of rare earth metals for nuclear generation and liquefied natural gas imports from the Middle East.

[110] NERC Southwest Blackout Event Reports: http://www.nerc.com/page.php?cid=5%7C407.

Assessment of Fault-Induced Delayed Voltage Recovery (FIDVR)

Fault-Induced Delayed Voltage Recovery (FIDVR) events are characterized by a depressed voltage for 5 to 30 seconds following a fault. These events are of concern because they show a temporary loss of voltage control in an area, and they pose a risk of cascading to a larger area, especially if another unexpected event occurs while the voltage is depressed. These events have been studied and are believed to be initiated by the stall of low inertia induction motors during the fault. Motors at risk of stalling include compressor-driven loads such as air conditioners. The subject of FIDVR events and their causes and solutions is covered in a NERC report on this topic.[111]

Coordinated Cyber or Physical Attacks on Electricity Infrastructure

One of the principal types of High-Impact, Low-Frequency (HILF) events facing the BPS is a concerted, well-planned cyber, physical, or blended attack conducted by an active adversary against multiple points on the system. Such an attack, although never experienced in North America, could damage or destroy key system components, significantly degrade system operating conditions, and, in extreme cases, result in prolonged outages to large parts of the system. The rapid convergence of the electric power system's infrastructure with information and communications technologies, combined with a new awareness of the sophistication of adversary capabilities, requires a fresh understanding of the risk and subsequent well-coordinated steps needed to improve the protection, resilience, and response capabilities of the BPS.

Electric Industry Workforce

The demand for industry workers to plan, maintain, and operate the BPS increases with the growing need for new infrastructure investments in electric generation, delivery, and use technologies and the rising need for technology innovation. The need for new infrastructure and technology innovations means a steady need for well-trained engineers and workers. The electric power industry is beginning to remedy the gap in qualified employees, but with the increased need to plan, design, and operate the BPS to accommodate a variety of new technologies and processes, there is still substantial interest in training and hiring workers to support industry needs and knowledge transfer.

Aging Infrastructure

Over the past decades, the majority of transmission investment was directed toward constructing new facilities to meet customer load demands, and comparatively little capital investment was expended for refurbishing existing facilities. The aging transmission system infrastructure has many challenges, such as the availability of spare parts, the obsolesce of older equipment, the ability to maintain equipment due to outage scheduling restrictions, and the aging of the work force and lost knowledge due to personnel retirements. Considering the diversity of equipment technologies and installation dates, potential for increased failure rates should be evaluated. However, implementation of any replacement strategy and in-depth training programs require additional capital investment, engineering and design resources, and construction labor resources, all of which are in relatively short supply.

[111] http://www.nerc.com/docs/pc/tis/FIDV_R_Tech_Ref_V1-1_PC_Approved.pdf.

Projected Demand, Resources, and Reserve Margins (2013–22)

The following section of the report represents the NERC-wide reference case and 10-year forecasts of Planning Reserve Margins, capacity resources, seasonal peak demands, and transmission.

Planning Reserve Margins

The electric industry has prepared plans to ensure the generation and delivery of reliable electricity throughout North America. Based on NERC's three different categories of Planning Reserve Margins (metrics used to measure the ability of a system's resources to meet customer demands based on current capacity plans and load forecasts), nearly all assessment areas will remain above the NERC Reference Margin Level throughout the 5-year (2017) assessment. The 10-year (2022) assessment shows a considerable decrease in Planning Reserve Margins, equating to more assessment areas being below the NERC Reference Margin Level (Figure 44, Figure 45).

Figure 44: 2017 NERC-Wide Peak Season Planning Reserve Margins

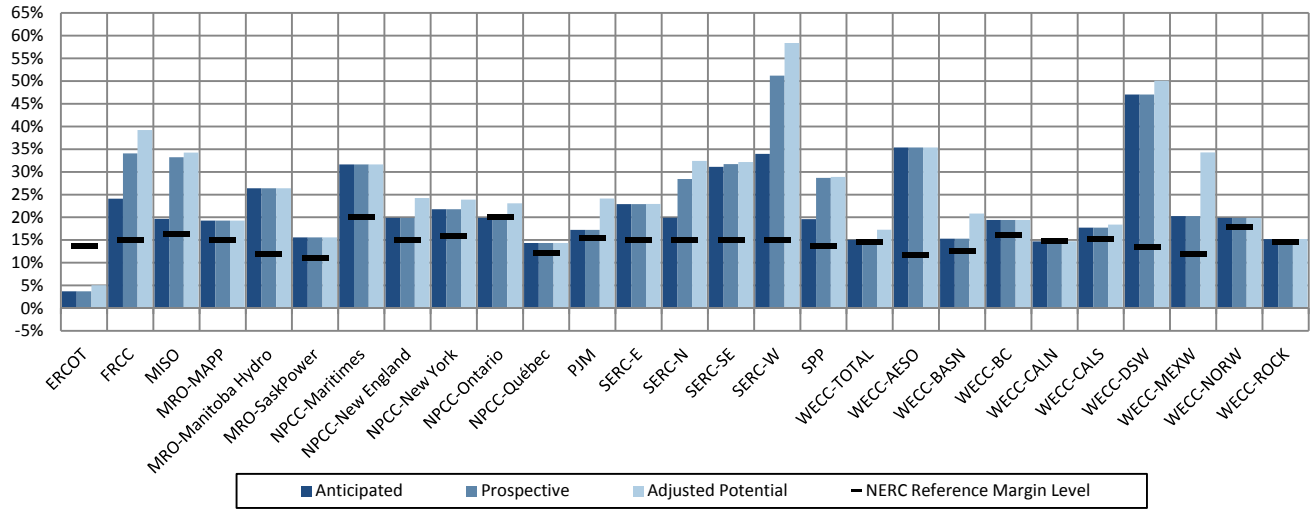
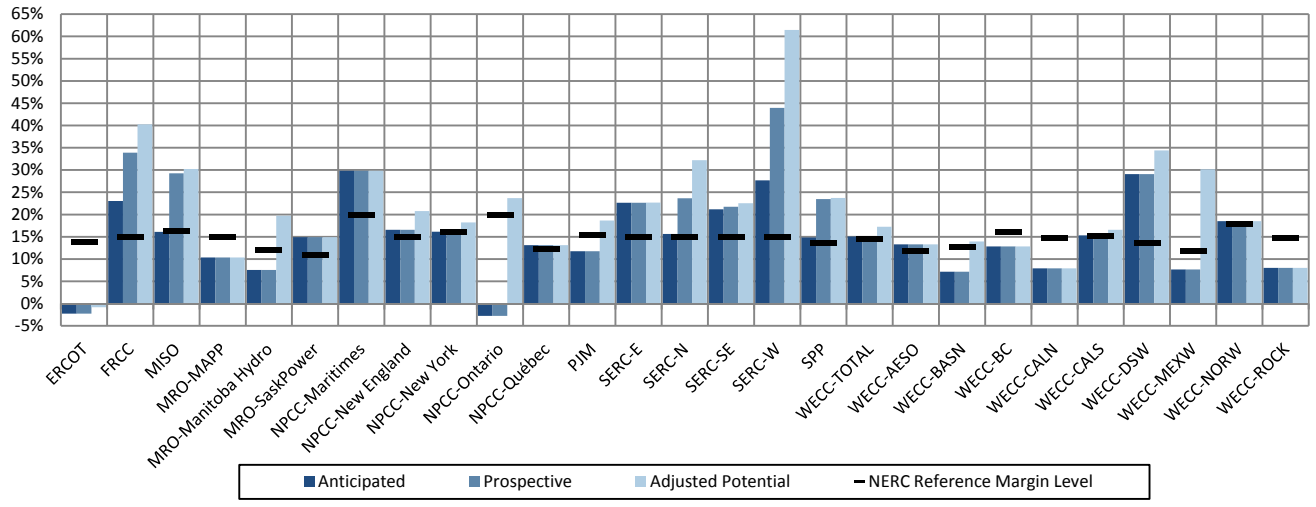


Figure 45: 2022 NERC-Wide Peak Season Planning Reserve Margins

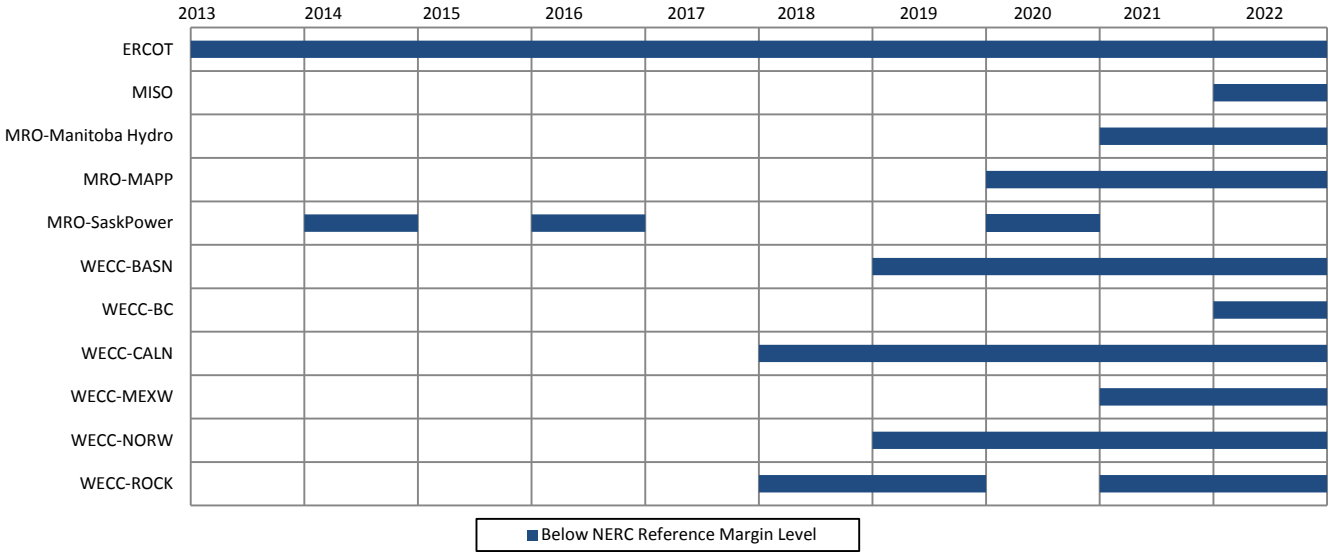


Significant challenges face the electric industry. These challenges may shift industry projections and cause the NERC reference case to change, which would add considerable uncertainty—not only in the long term, but in the short-term, as well. Where markets exist, signals for new capacity must be effective for planning purposes and must reflect the lead times necessary to construct new generation and any associated transmission. Regulations aimed at controlling environmental

impacts caused by higher-emission generating plants create additional concerns for industry planners, as regulatory compliance deadlines could conflict with existing capacity plans and approval processes. Potential impacts could be both local and regional and must be addressed accordingly.

The ERCOT Assessment Area will face resource adequacy challenges throughout the long-term outlook due to the uncertainty of plans for new capacity—demand continues to grow at a compound annual growth rate of 2.35 percent. Although ERCOT and the Public Utility Commission of Texas (PUCT) have been proactive, new market rules and increased demand response impacts have not been in place long enough to curb the continued decline of Planning Reserve Margins.[112] Planning Reserve Margins remain below the NERC Reference Margin Level of 13.75 percent throughout the assessment period, turning negative in the latter years. Uncertainty surrounding plans for future capacity is the most notable issue that may result in the need for emergency actions. Until new capacity projects come online, the use of interruptible load, voltage reduction, or the implementation of other ERCOT-specific Energy Emergency Alerts (EEA) plans may become necessary. Impacts could be exacerbated by extreme weather conditions, such as drought and heat waves that have become an ongoing concern in recent years. This would result in the highest recorded peak demand for the area during the 2011 summer. Although improved 2012 spring rainfall has temporarily alleviated drought conditions, the potential for extreme heat and corresponding increase in demand remains a monumental concern that will only be mitigated by securing additional capacity or demand-side management resources. Adequacy concerns in ERCOT could be further exacerbated by the potential for more stringent emission requirements from the MATS rule, which could result in additional project delays or cancellations of new capacity (Figure 46).

Figure 46: Assessment Areas with Anticipated Reserve Margins that fall below the NERC Reference Margin Level by 2022



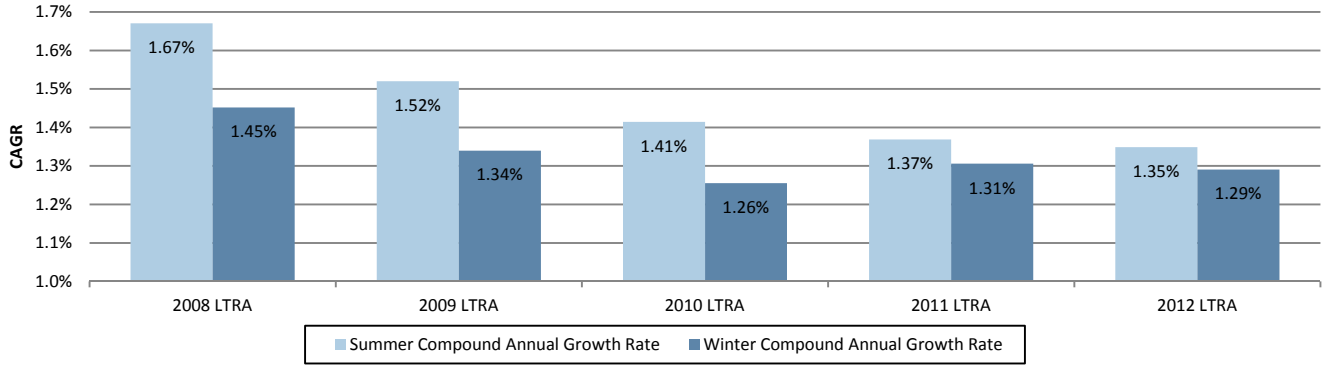
As the Ontario Assessment Area phases out all remaining coal-fired capacity by 2014, the province must manage a shifting resource mix. Plans call for an increased dependence on nuclear resources. Several refurbished units are expected to return to service after prolonged outages, with all of the coal units retired or converted to cleaner fuels. Retired units have been replaced by new gas units, renewable generation, and restarted nuclear units. With these changing conditions, Planning Reserve Margins remain adequate through 2017 but significantly decrease thereafter, becoming negative in the final years of the outlook. Additional conceptual resources will be necessary, including scheduled refurbishments at both the Bruce and Darlington nuclear plants, along with potential nuclear new-build at the Darlington site.

[112] The actions taken need evaluation time. While there have been no significant announcements of new generation yet, the work of the PUCT and ERCOT participants continues.

Demand

The North American electricity demand growth for the summer season during the next decade (2013–2022) remains essentially unchanged from last year's outlook. NERC-wide, the 10-year compound annual growth rate (CAGR) for on-peak summer demand is 1.35 percent—slightly lower than what was reported in the *2011 Long-Term Reliability Assessment*. The 10-year growth outlook for winter demand also remains steady at 1.29 percent. There is a 0.02 percent decline compared to a year earlier, but demand still remains above its lowest outlook in 2010 (Figure 47).

Figure 47: NERC-Wide Compound Annual Growth Rate of Seasonal Total Internal Demand



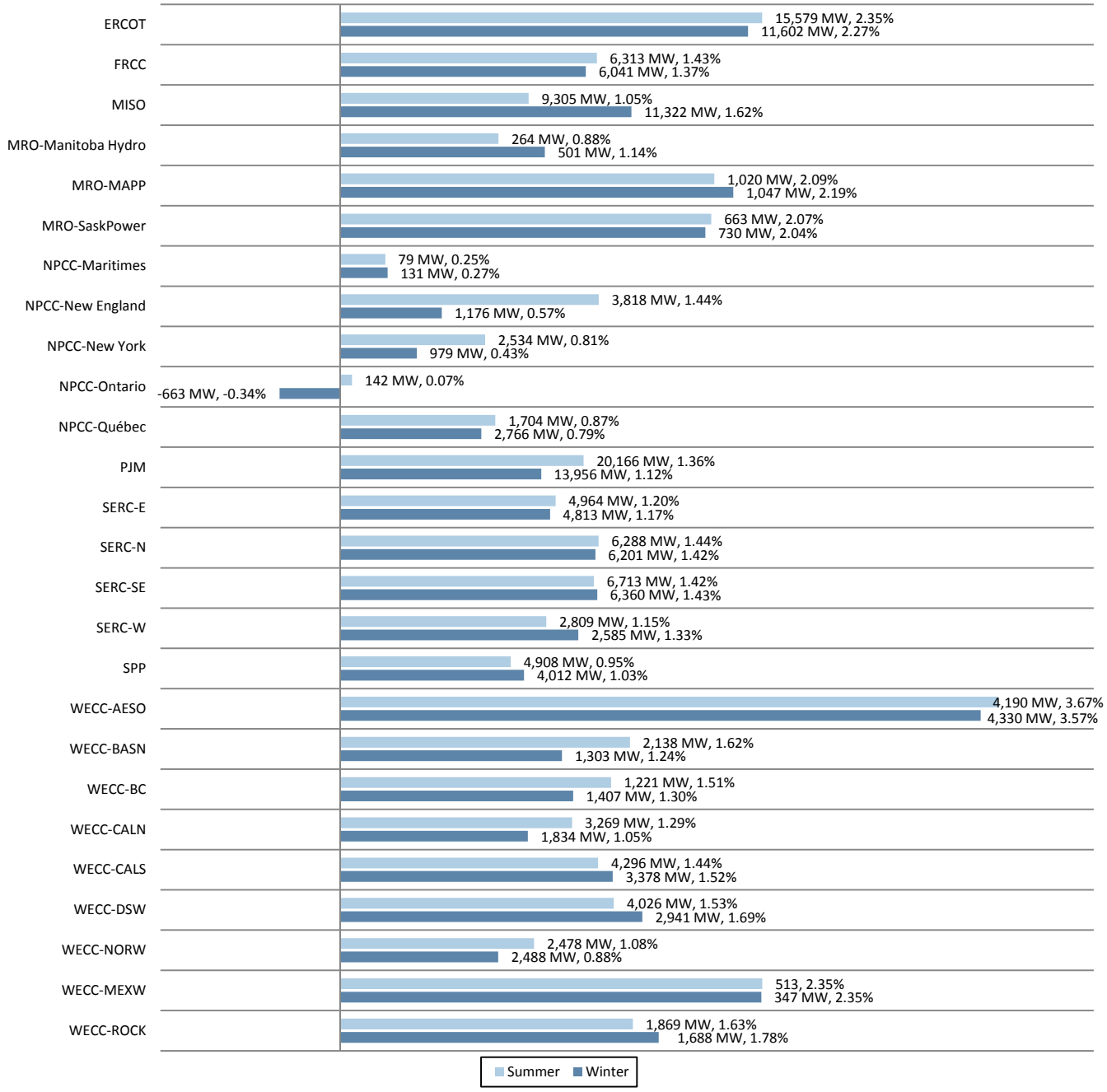
Peak load forecasts provide a future view on electricity infrastructure needs. According to the *2012LTRA* reference case, the demand growth for the summer season has reached its lowest level since NERC began reporting this data in 1967. This slower growth outlook will have important implications on the need for new capacity resources.

Despite a slower growth forecast for North America as a whole, several assessment areas project significant electricity demand growth during the next decade, including Alberta (WECC-AESO) and ERCOT. Alberta covers the third-largest proven oil reserves in the world (over 170 billion barrels), and the extraction of these oil sands by surface mining will create substantial load growth—both to support mining operations and corresponding population increases. The Alberta Assessment Area projects average growth of over 3.5 percent annually, totaling over 4 GW by 2022. Continued population growth throughout Texas is largely responsible for increasing electricity demand in load centers during the 10-year outlook.

Although Canada as a whole projects moderate economic growth and corresponding electricity demand growth in the coming decade, Ontario will lag behind in the near term. High commodity prices—in particular oil—will benefit other parts of Canada over Ontario's manufacturing and export-based economy. During the 10-year period, Ontario's economy is expected to continue to undergo structural change. As the economy matures, there is likely to be a transition from an energy-intense industrial process-based economy to one with a larger service sector and specialized or high-value-added manufacturing, which could lead to a less energy-intense economy. Demand conservation is another underlying driver for slower demand growth. Accordingly, the NPCC-Ontario Assessment Area is expecting flat demand growth for the 10-year summer outlook with negative growth during the winter.

Most of the remaining assessment areas are planning for moderate demand growth over the 10-year period, attributing mostly local economic conditions as primary determinants (Figure 48).

Figure 48: Peak Demand Growth (MW) and Compound Annual Growth Rate (%) of Total Internal Demand by Assessment Area



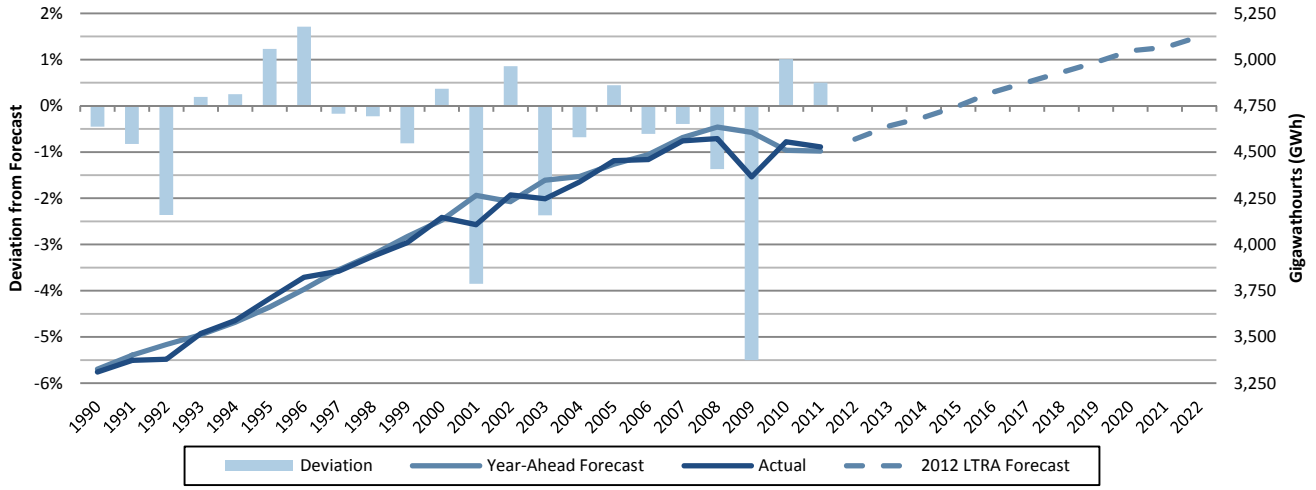
Load Forecast Uncertainty

Forecasting electricity demand has become more complicated in recent years, and this issue was addressed thoroughly in the *2011 Long-Term Reliability Assessment*.[113] Conclusions highlighted the challenges of redefining methods based on customer and utility behavior, the current state and outlook of the North American economy, and new developments in long-term weather projections. These challenges continue to make load forecasting more complex and are highlighted by the year-ahead outlook for NERC-wide Net Energy for Load (NEL), a measurement of annual generation in megawatt-hours

[113] *2011 Long-Term Reliability Assessment*. Load Forecasting Uncertainty. P. 107. http://www.nerc.com/files/2011%20LTRA_Final.pdf.

(MWh). Although year-ahead projections were extremely accurate during the 1990s when economic growth was relatively stable, the mild recession during the early 2000s largely contributed to the actual NEL falling below the forecast. Similarly, the 2008 recession caused actual demand to drop significantly, which further supports the high correlation between economic conditions and electricity use (Figure 49).

Figure 49: Net Energy for Load – Forecast vs. Actual



While unstable economic conditions have added complexity to load forecasting in recent years, utility integration of smart grid-related technologies has also had an influence. Electricity use with smart grid programs has encouraged consumers to reduce or otherwise change their electricity usage during peak periods in response to time-based rates or other forms of financial incentives. Continued enrollment in large-scale demand-side management programs by industrial and commercial customers will bear an even greater impact on load forecasts. As demand-side management programs continue to evolve, load forecasting methods will need to adapt accordingly to ensure demand projections remain a dependable source of information for industry planners.

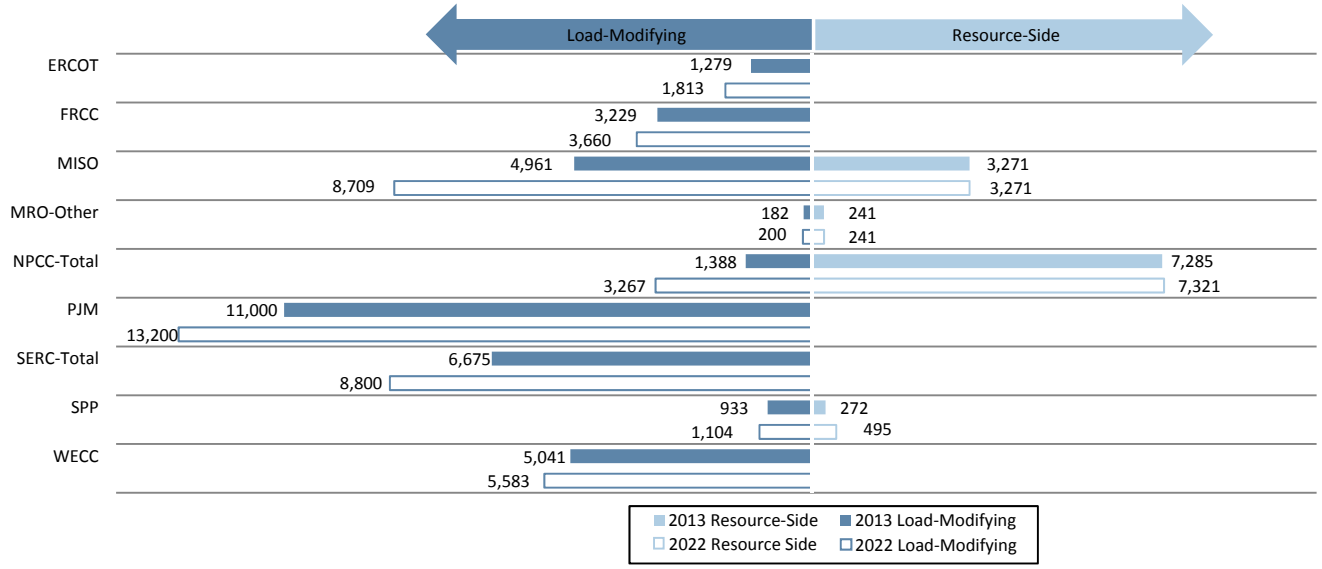
Demand-Side Management

The use of demand-side resources is expected to expand throughout North America, continuing the trend NERC has observed since initially collecting this data in the 1980s. In recent years, as various new demand response and energy efficiency programs have been introduced, NERC has strived to modify data collection and presentation as necessary to keep up with an industry that continues to evolve. Additional information regarding how NERC collects and reports demand response is included in Appendix V and VII in this assessment.

As increased demand-side management in recent years has provided more flexibility for system operators, continued penetration of these programs is forecast throughout the assessment period. However, it is important to consider how each area forecasts the future availability of demand response during peak demand periods. Generally, most demand response programs involve short-term contracts between participants that provide increased certainty during the first three years. In subsequent years, expected performance is based on area-specific assumptions.

Demand Response as a percentage of Total Internal Demand is highest in the NPCC-New England Assessment Area, amounting to 10.1 percent in 2013. Projections are for a 5 percent increase during the next 10 years. By 2022, nearly 5 GW of load-modifying and resource-side demand response is projected to be available during the summer peak. Similarly, MISO is planning for over 3.7 GW in additional load-modifying demand response during the assessment period (Figure 50).

Figure 50: NERC-Wide Demand Response: 10-Year Outlook

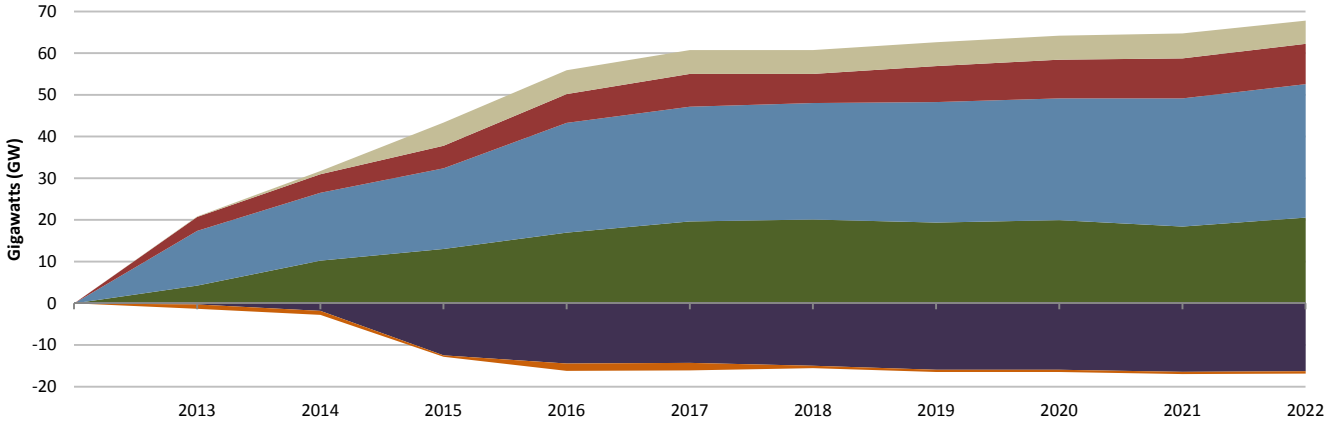


In many cases, DR—especially load categorized as a resource—can offer more flexibility to operators and provide redispatching options used to maintain reliability. Specifically, demand response programs in the industrial and commercial sectors are even more impactful and usually involve contracts that require participants to respond when called upon by system operators. Contract lengths rarely extend beyond three years with provisions, which limits the number of times a participant will be called to respond in a given year. However, planners should consider the potential reliability consequences of over-dependence on these large-scale demand response programs. Specifically, prolonged cases of extreme demand could trigger the repeated use of demand response, ultimately causing customers to forego future participation in these programs.

Generation

Projections for future generation are based on several factors and can vary by NERC Region or Assessment Area. The economic outlook, fuel prices, regulations, and load forecasts are all volatile and have important implications in regard to decisions to build new capacity. According to the *2012LTRA* reference case, a net of 51.3 GW of on-peak generation is expected to be added during the 10-year NERC-wide outlook (Figure 51).

Figure 51: NERC-Wide Capacity: 10-Year Outlook[114]



	Current		2022 Planned			2022 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	307,201	29.78%	290,915	26.86%	-16,286	278,775	22.61%	-28,426
Petroleum	52,498	5.09%	51,954	4.80%	-544	51,377	4.17%	-1,121
Gas	397,464	38.53%	429,462	39.65%	31,998	529,328	42.94%	131,863
Nuclear	113,821	11.03%	123,525	11.41%	9,704	136,361	11.06%	22,540
Other/Unknown	271	0.03%	5,840	0.54%	5,569	12,683	1.03%	12,412
Renewables	160,420	15.55%	181,311	16.74%	20,891	224,235	18.19%	63,815
TOTAL	**1,031,676**	**100.00%**	**1,083,007**	**100.00%**	**51,332**	**1,232,759**	**100.00%**	**201,083**

Coal

Projections for coal-fired generation in the *2012LTRA* Reference case point to a decline during the 10-year outlook. In 2012, coal's total on-peak contribution is approximately 30 percent—a slight decrease compared to 2011. Its share will continue to decline, falling to under 27 percent in 2022, due to the projected retirements of over 16 GW throughout the next decade. Conceptual plans for newer coal plants, some of which include carbon capture and storage (CCS) technologies, could partially offset retirements by adding approximately 7 GW. Economic decisions caused by impacts—both direct and indirect—of environmental regulations, coupled with presently inexpensive natural gas prices, are two key factors that contribute to a shifting capacity mix. Coal retirements are widely projected throughout North America, with reliability impacts dependent on each assessment area's resource mix.

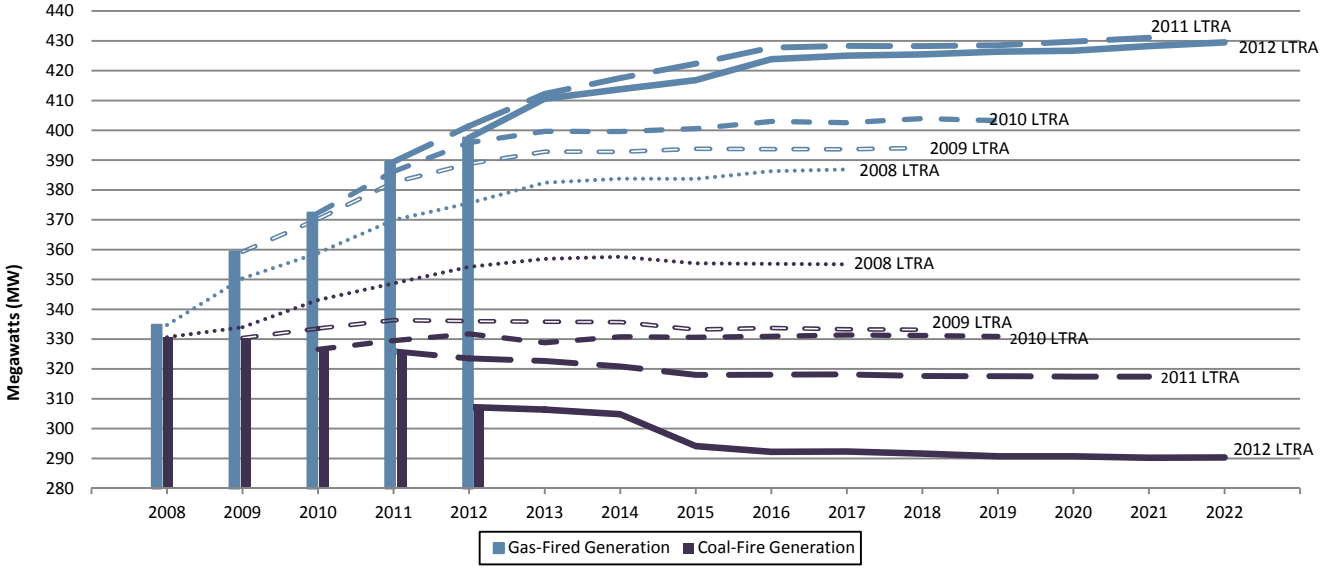
The reference case includes some consideration for federal and state regulations that are expected to impact coal-fired capacity in the United States. This includes regulation that supports the Clean Air Act[115] but does not include the full extent of these impacts. The age of a coal plant can impact retirement decisions spurred in part by environmental regulations with impending costs to either retrofit applicable units with expensive environmental control equipment, or close the plant permanently. Moreover, the potential investment in retrofit equipment generally becomes less economical if fewer years remain on the life of a given plant. The potential investment in retrofit equipment generally becomes less economical if fewer years remain on the life of a given plant. In NPCC, the New England Assessment Area includes over 6 GW of fossil-fueled generating units (primarily coal or oil) that are at least 40 years old, creating conditions more susceptible to unit retirements than retrofits. The New York Assessment Area has also reported 1,200 MW of confirmed retirements.

On an assessment-area basis, Ontario and PJM anticipate the most significant reduction in coal during the 10-year outlook, with unit retirement projections amounting to 3.4 GW and 12.7 GW, respectively. In Ontario, two coal-fired units totaling 980 MW were closed in 2011, with the remaining 9 units in the province to be taken offline by the end of 2014. The PJM

[114] Represents the "non-coincident" NERC-wide on-peak capacity for each assessment area.
[115] http://www.epa.gov/air/caa/; http://www.epa.gov/airtransport/; http://www.epa.gov/airquality/powerplanttoxics/index.html.

projections indicate 14 units (1.3 GW) will shut down during 2012 with 60 additional units (9.8 GW) to close by 2015. Unit retirements in the latter years of the 10-year outlook are less certain, and reliability impacts are still being analyzed (Figure 52).

Figure 52: NERC-Wide Coal- and Gas-Fired Generation Outlook: *2008-2012LTRA* Reference Case Comparison



According to reference cases from the last four long-term reliability asessments, NERC-wide coal capacity on peak declined by approximately 23.5 GW, from 330.6 GW in 2008 to 307.1 GW in 2012. Most of this decline in coal occurred during 2011, as the finalization of several environmental regulations—specifically air-related regulations—clearly impacted decisions of plant owners and industry planners throughout the United States. Alternatives to coal have also become more prominent in recent years. State and provincial renewable energy requirements and goals have created more localized policy incentives to encourage more contribution of renewables in the capacity mix. For example, the Atikokan Generating Station, a coal plant in the NPCC-Ontario Assessment Area, is undergoing conversion to biomass that is expected to take place by 2014. Additionally, the role of coal has been further diminished by the relatively new capability to run existing gas-fired units as baseload generation with a higher capacity factor (instead of only during peak periods).

Natural Gas

As coal's contribution continues to decline, gas-fired capacity is projected to outpace all other forms of generation in growth, except for renewable, adding 32 GW by 2022 in the *2012LTRA* Reference case. Conceptual projections amount to an additional 68 GW, which is indicative of the industry's high expectations for gas-fired generation to account for a majority of capacity introduced during the 10-year outlook.

The conversion to—or development of—new gas-fired units has become an attractive alternative to coal with the current affordability of natural gas and the added benefit of relatively lower emissions. New gas-fired units also have relatively low capital costs, with a lead time of only two years compared to coal or nuclear plants, whose lead times range from 5 to 12 years. In many cases, existing coal-fired plant sites are being converted to gas-fired plants. In Ontario, plans are in place to convert at least two units from coal to natural gas by 2014, with several other coal units currently under consideration. Several coal plants in the WECC Assessment Area are also projecting unit conversions to natural gas as alternatives to retrofitting or retiring coal units.

The extensive growth in gas-fired capacity may not be caused entirely by the enduring decline in coal—the ease of converting a coal-fired plant to a gas-fired plant may help alleviate reliability concerns that are inherent to large base-load retirements. The use of existing facilities (such as transmission, cooling towers, and other on-site facilities) makes

converting a plant especially economical and ensures the continued generation of reactive power used to serve nearby loads.

From a reliability aspect, the increase in gas-fired generation compliments the inherent variability of renewable resources that are also experiencing continued growth. As wind and solar resources contribute more to service load at times of peak demand, gas-fired units can be ramped up or down as necessary, thus allowing operators more flexibility to offset renewable variability.

Nuclear

NERC-wide, nuclear additions are projected to add 10.4 GW of on-peak capacity by 2022. Unit uprates account for a significant portion of these additions and are partially offset by plans to take units offline for refurbishment in the later years of the assessment. The contribution from nuclear power remains relatively stable throughout the 10-year outlook. This is partially due to the continued operation of plants built over 40 years ago. In the United States, the Nuclear Regulatory Commission (NRC) has provided operating license renewals for 71 of the total fleet of 104 reactors, while an additional 15 applications are currently under review. The Canadian Nuclear Safety Commission (CNSC) maintains similar regulatory oversight of seven nuclear power plants at five sites in Canada.

For the first time in almost three decades, the NRC voted in February 2012 to grant a combined construction and operating license to four units in the SERC Region. Units 3 and 4 at the Vogtle Nuclear Power Plant in the SERC-SE Assessment Area are expected to come online by the end of 2017, providing 2.2 GW of additional capacity. Units 2 and 3 of the VC Summer Plant in SERC-E are also expected to be operating as soon as 2016 and 2019, respectively, with each reactor providing 1.1 GW of capacity. Finally, the Bellefonte Unit 1 reactor is included in the Tennessee Valley Authority (TVA) Integrated Resource Plan and for the purpose of this assessment is categorized as Future-Planned, with an in-service date of June 2020. License approval from the NRC is currently suspended.

In Canada, the Point Lepreau nuclear plant (totaling 660 MW) is projected to return to service by the end of 2012 after a four-year extended outage and will serve as the single largest unit and only nuclear facility in the Maritimes Assessment Area.

In NPCC-Ontario, nuclear generation will remain the largest contributor, providing over half the electricity in the area. Two units at the Bruce A Nuclear Generating Station are currently undergoing refurbishments that will add 1,500 MW upon completion. In the final years of the 10-year outlook, plans call for the refurbishment of several units at the Bruce and Darlington Nuclear Generating Stations. The Pickering Nuclear Generating Station (Units 5, 6, 7, and 8) is scheduled for retirement by 2016 but is currently licensed through 2020, and extending the operating life of the four units is currently under review, with a decision expected by the end of 2013.

In the NPCC-Québec Assessment Area, the recently announced closure of the Gentilly-2 generating station is scheduled for December 2012 and is incorporated into the *2012LTRA* Reference case.

Renewables

Contribution from renewable resources will continue to grow, as significant capacity additions are projected for both wind and solar throughout North America. In 2012, renewable generation—including hydro as a share of total on-peak contribution—is 15.6 percent and expected to reach almost 17 percent by the end of 2022. Projections for new solar in WECC—especially Southern California and Arizona, (WECC-CALS and WECC-DSW Assessment Areas)—account for most of the 7 GW of NERC-wide solar additions during the next 10 years. WECC also has aggressive plans for 13.4 GW of new wind generation projected throughout the assessment period. In the NPCC Region, the Ontario and Québec Assessment Areas will more than double current wind capacity during the next decade, adding approximately 5.2 GW. SPP planners expect the addition of 11.6 GW of planned wind projects. PJM and ERCOT have project plans totaling 2,298 MW and 1,918 MW of installed wind capacity, respectively. Non-hydro renewable capacity additions are currently supported by federal tax credits

and state Renewable Portfolio Standards (RPS); however, changes in the political landscape in the United States could put the federal tax credits in jeopardy.

Additions of biomass capacity are most substantial in FRCC and most of the SERC Region. Biomass is projected to remain the largest renewable resource in the FRCC Assessment Area, growing from 374 MW to 736 MW during the 10-year outlook. Planned additions for biomass capacity in the SERC-E, SERC-SE, and SERC-W Assessment Areas amount to 216 MW. Similar additions are also planned in the PJM, MRO-SaskPower, and NPCC-Maritimes Assessment Areas.

Uprates and additions in the NPCC-Québec Assessment Area account for nearly half of the hydropower additions during the 10-year outlook. Specifically, the commissioning of several new hydropower generating stations will add 2,160 MW to Hydro-Québec's capacity mix, with an additional 500 MW of capacity uprates at existing plants.

NERC-Wide Summary Tables

Table Notes

- All values are in megawatts, unless noted otherwise.
- CAGR: Compound Annual Growth Rate
- Net Internal Demand excludes all load-modifying Demand Response; primary demand statistic for all NERC Planning Reserve Margin calculations.
- Reference: NERC Reference Margin Level as assigned by each NERC Region. If no Reference Margin Level is provided, NERC applies a 15 percent and 10 percent level for thermal and hydro systems, respectively. The Reference Margin Level is subject to change by season or year. For additional information, see respective assessment area section.

Demand, Resources, and Reserve Margins: 2013 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	65,649	66,928	74,448	74,448	74,656	13.40%	13.40%	13.72%	13.75%
FRCC	43,041	46,270	54,823	58,732	60,439	27.37%	36.46%	40.42%	15.00%
MISO	89,318	94,279	108,007	119,723	119,903	20.92%	34.04%	34.24%	16.30%
MRO-MAPP	4,904	4,995	6,344	6,344	6,344	29.36%	29.36%	29.36%	15.00%
NPCC-New England	26,629	27,765	35,265	35,265	35,329	32.43%	32.43%	32.67%	15.00%
NPCC-New York	33,696	33,696	42,127	42,127	42,150	25.02%	25.02%	25.09%	16.00%
PJM	145,254	156,254	184,882	184,882	186,581	27.28%	27.28%	28.45%	15.40%
SERC-E	41,805	43,733	52,271	52,271	52,285	25.03%	25.03%	25.07%	15.00%
SERC-N	43,808	45,750	54,020	57,939	57,939	23.31%	32.26%	32.26%	15.00%
SERC-SE	47,900	49,799	62,107	62,407	62,549	29.66%	30.29%	30.58%	15.00%
SERC-W	25,015	25,921	34,335	38,854	38,864	37.26%	55.32%	55.36%	15.00%
SPP	54,247	55,180	65,335	70,419	70,524	20.44%	29.81%	30.01%	13.60%
WECC-BASN	12,667	13,776	16,154	16,154	16,154	27.53%	27.53%	27.53%	12.60%
WECC-CALN	25,841	26,645	29,757	29,757	29,757	15.16%	15.16%	15.16%	14.71%
WECC-CALS	29,311	31,319	34,012	34,012	34,086	16.04%	16.04%	16.29%	15.14%
WECC-DSW	27,034	27,576	39,623	39,623	39,804	46.57%	46.57%	47.24%	13.50%
WECC-NORW	24,310	24,380	28,919	28,919	28,920	18.96%	18.96%	18.96%	17.90%
WECC-ROCK	11,434	11,904	14,285	14,285	14,288	24.93%	24.93%	24.96%	14.65%
TOTAL-UNITED STATES	751,862	786,170	936,713	966,160	970,572	24.59%	28.50%	29.09%	15.00%
MRO-Manitoba Hydro	3,210	3,210	4,597	4,597	4,597	43.21%	43.21%	43.21%	12.00%
MRO-SaskPower	3,184	3,275	3,628	3,628	3,628	13.93%	13.93%	13.93%	11.00%
NPCC-Maritimes	3,104	3,435	6,597	6,597	6,597	112.52%	112.52%	112.52%	20.00%
NPCC-Ontario	23,301	23,301	31,938	31,938	31,938	37.07%	37.07%	37.07%	19.70%
NPCC-Québec	21,115	21,115	31,821	31,821	31,821	50.71%	50.71%	50.71%	9.60%
WECC-AESO	10,903	10,941	12,994	12,994	12,994	19.18%	19.18%	19.18%	12.24%
WECC-BC	8,449	8,449	11,975	11,975	11,975	41.74%	41.74%	41.74%	12.51%
TOTAL-CANADA	73,266	73,726	103,550	103,550	103,550	41.34%	41.34%	41.34%	10.00%
WECC-MEXW	2,203	2,203	2,641	2,641	2,641	19.89%	19.89%	19.89%	11.86%
TOTAL-MÉXICO	2,203	2,203	2,641	2,641	2,641	19.89%	19.89%	19.89%	11.86%
TOTAL-NERC	**827,330**	**862,098**	**1,042,904**	**1,072,351**	**1,076,763**	**26.06%**	**29.62%**	**30.15%**	**15.00%**

Demand, Resources, and Reserve Margins: 2013/2014 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	50,263	51,734	76,915	76,915	78,081	53.03%	53.03%	55.34%	13.75%
FRCC	43,049	46,367	58,229	61,616	62,777	35.26%	43.13%	45.83%	15.00%
MISO	69,663	72,572	109,462	121,135	121,156	57.13%	73.89%	73.92%	16.30%
MRO-MAPP	4,858	4,858	6,673	6,673	6,673	37.37%	37.37%	37.37%	15.00%
NPCC-New England	21,383	22,510	37,848	37,848	38,098	77.00%	77.00%	78.17%	15.00%
NPCC-New York	24,929	24,929	42,883	42,883	43,216	72.02%	72.02%	73.36%	16.00%
PJM	121,160	132,160	184,925	184,925	186,623	52.63%	52.63%	54.03%	15.40%
SERC-E	42,042	43,582	54,712	54,712	54,726	30.14%	30.14%	30.17%	15.00%
SERC-N	43,734	45,713	68,909	72,900	72,900	57.56%	66.69%	66.69%	15.00%
SERC-SE	44,652	46,534	64,449	64,749	64,806	44.34%	45.01%	45.14%	15.00%
SERC-W	19,731	20,497	42,929	47,197	47,207	117.57%	139.20%	139.25%	15.00%
SPP	40,983	41,714	61,197	66,023	67,069	49.32%	61.10%	63.65%	13.60%
WECC-BASN	10,842	11,134	13,760	13,760	13,760	26.91%	26.91%	26.91%	13.49%
WECC-CALN	18,407	18,664	22,557	22,557	22,557	22.55%	22.55%	22.55%	11.86%
WECC-CALS	22,360	23,229	34,561	34,561	34,635	54.57%	54.57%	54.90%	11.03%
WECC-DSW	17,845	18,124	34,086	34,086	34,253	91.01%	91.01%	91.95%	13.96%
WECC-NORW	30,217	30,270	36,285	36,285	36,285	20.08%	20.08%	20.08%	19.90%
WECC-ROCK	9,565	9,833	14,023	14,023	14,259	46.61%	46.61%	49.08%	15.68%
TOTAL-UNITED STATES	635,683	664,424	964,403	992,850	999,083	51.71%	56.19%	57.17%	15.00%
MRO-Manitoba Hydro	4,661	4,661	5,996	5,996	5,996	28.63%	28.63%	28.63%	12.00%
MRO-SaskPower	3,580	3,671	4,125	4,125	4,125	15.24%	15.24%	15.24%	11.00%
NPCC-Maritimes	5,169	5,421	6,878	6,878	6,878	33.06%	33.06%	33.06%	20.00%
NPCC-Ontario	22,192	22,192	32,060	32,060	32,074	44.47%	44.47%	44.53%	18.60%
NPCC-Québec	37,810	37,810	42,483	42,483	42,483	12.36%	12.36%	12.36%	10.00%
WECC-AESO	11,664	11,664	13,831	13,831	13,831	18.58%	18.58%	18.58%	11.71%
WECC-BC	11,416	11,416	13,384	13,384	13,384	17.24%	17.24%	17.24%	16.16%
TOTAL-CANADA	96,492	96,835	118,757	118,757	118,770	23.07%	23.07%	23.09%	10.00%
WECC-MEXW	1,494	1,494	2,434	2,434	2,434	62.92%	62.92%	62.92%	10.71%
TOTAL-MÉXICO	1,494	1,494	2,434	2,434	2,434	62.92%	62.92%	62.92%	10.71%
TOTAL-NERC	**733,669**	**762,753**	**1,085,594**	**1,114,040**	**1,120,287**	**47.97%**	**51.85%**	**52.70%**	**15.00%**

Demand, Resources, and Reserve Margins: 2014 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	68,403	69,721	74,498	74,498	75,074	8.91%	8.91%	9.75%	13.75%
FRCC	43,618	46,857	55,343	60,273	63,001	26.88%	38.18%	44.44%	15.00%
MISO	90,707	96,129	108,139	119,855	120,036	19.22%	32.13%	32.33%	16.30%
MRO-MAPP	5,024	5,117	6,370	6,370	6,370	26.79%	26.79%	26.79%	15.00%
NPCC-New England	26,877	28,275	35,160	35,160	35,498	30.82%	30.82%	32.07%	15.00%
NPCC-New York	33,914	33,914	42,077	42,077	42,129	24.07%	24.07%	24.22%	16.00%
PJM	146,642	159,842	185,879	185,879	188,912	26.76%	26.76%	28.83%	15.40%
SERC-E	42,412	44,457	52,658	52,658	52,672	24.16%	24.16%	24.19%	15.00%
SERC-N	44,387	46,542	55,142	59,061	59,061	24.23%	33.06%	33.06%	15.00%
SERC-SE	48,738	50,838	62,901	63,201	63,443	29.06%	29.68%	30.17%	15.00%
SERC-W	25,257	26,166	34,943	39,462	40,172	38.35%	56.24%	59.05%	15.00%
SPP	54,794	55,732	66,086	71,170	71,280	20.61%	29.89%	30.09%	13.60%
WECC-BASN	13,025	14,144	15,909	15,909	16,355	22.14%	22.14%	25.57%	12.60%
WECC-CALN	26,154	26,971	30,031	30,031	30,031	14.82%	14.82%	14.82%	14.71%
WECC-CALS	29,901	31,896	36,162	36,162	36,236	20.94%	20.94%	21.19%	15.14%
WECC-DSW	27,252	27,847	39,110	39,110	39,551	43.51%	43.51%	45.13%	13.50%
WECC-NORW	24,609	24,694	29,042	29,042	29,043	18.02%	18.02%	18.02%	17.90%
WECC-ROCK	11,619	12,107	14,164	14,164	14,167	21.91%	21.91%	21.93%	14.65%
TOTAL-UNITED STATES	763,332	801,249	943,615	974,083	983,032	23.62%	27.61%	28.78%	15.00%
MRO-Manitoba Hydro	3,238	3,238	4,607	4,607	4,607	42.26%	42.26%	42.26%	12.00%
MRO-SaskPower	3,335	3,426	3,762	3,762	3,762	12.79%	12.79%	12.79%	11.00%
NPCC-Maritimes	3,138	3,469	6,610	6,610	6,610	110.64%	110.64%	110.64%	20.00%
NPCC-Ontario	23,080	23,080	30,023	30,023	30,035	30.08%	30.08%	30.14%	18.60%
NPCC-Québec	21,550	21,550	31,755	31,755	31,755	47.36%	47.36%	47.36%	10.00%
WECC-AESO	11,510	11,548	13,765	13,765	13,765	19.59%	19.59%	19.59%	12.24%
WECC-BC	8,684	8,684	12,218	12,218	12,218	40.70%	40.70%	40.70%	12.51%
TOTAL-CANADA	74,535	74,995	102,739	102,739	102,751	37.84%	37.84%	37.86%	10.00%
WECC-MEXW	2,260	2,260	2,923	2,923	2,923	29.35%	29.35%	29.35%	11.86%
TOTAL-MÉXICO	2,260	2,260	2,923	2,923	2,923	29.35%	29.35%	29.35%	11.86%
TOTAL-NERC	**840,127**	**878,504**	**1,049,277**	**1,079,745**	**1,088,707**	**24.90%**	**28.52%**	**29.59%**	**15.00%**

Demand, Resources, and Reserve Margins: 2014/2015 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	50,533	52,063	76,976	76,976	79,552	52.33%	52.33%	57.43%	13.75%
FRCC	44,228	47,568	61,341	63,983	64,399	38.69%	44.67%	45.61%	15.00%
MISO	74,965	78,143	109,692	121,524	121,704	46.32%	62.11%	62.35%	16.30%
MRO-MAPP	4,999	4,999	6,713	6,713	6,713	34.28%	34.28%	34.28%	15.00%
NPCC-New England	21,285	22,670	37,197	37,197	37,570	74.75%	74.75%	76.51%	15.00%
NPCC-New York	24,999	24,999	41,530	41,530	42,194	66.13%	66.13%	68.78%	16.00%
PJM	121,571	134,771	185,881	185,881	188,914	52.90%	52.90%	55.39%	15.40%
SERC-E	42,408	43,977	55,191	55,191	55,205	30.14%	30.14%	30.18%	15.00%
SERC-N	44,212	46,433	68,909	72,900	72,900	55.86%	64.89%	64.89%	15.00%
SERC-SE	45,103	47,197	65,284	65,584	65,742	44.75%	45.41%	45.76%	15.00%
SERC-W	20,042	20,835	43,537	47,805	48,515	117.23%	138.53%	142.07%	15.00%
SPP	41,345	42,010	61,824	66,651	67,756	49.53%	61.21%	63.88%	13.60%
WECC-BASN	10,913	11,215	13,513	13,513	13,959	23.82%	23.82%	27.91%	13.49%
WECC-CALN	18,707	18,977	24,470	24,470	24,470	30.81%	30.81%	30.81%	11.86%
WECC-CALS	22,893	23,753	34,228	34,228	34,302	49.51%	49.51%	49.83%	11.03%
WECC-DSW	18,095	18,380	34,397	34,397	34,569	90.09%	90.09%	91.04%	13.96%
WECC-NORW	30,507	30,577	36,683	36,683	36,683	20.24%	20.24%	20.25%	19.90%
WECC-ROCK	9,709	9,978	13,318	13,318	13,631	37.17%	37.17%	40.39%	15.68%
TOTAL-UNITED STATES	646,514	678,545	970,684	998,544	1,008,779	50.14%	54.45%	56.03%	15.00%
MRO-Manitoba Hydro	4,712	4,712	6,039	6,039	6,039	28.18%	28.18%	28.18%	12.00%
MRO-SaskPower	3,738	3,829	4,161	4,161	4,161	11.33%	11.33%	11.33%	11.00%
NPCC-Maritimes	5,166	5,420	6,893	6,893	6,893	33.45%	33.45%	33.45%	20.00%
NPCC-Ontario	21,890	21,890	29,908	29,908	30,192	36.63%	36.63%	37.92%	19.80%
NPCC-Québec	38,062	38,062	42,971	42,971	42,971	12.90%	12.90%	12.90%	10.50%
WECC-AESO	12,162	12,162	15,685	15,685	15,685	28.97%	28.97%	28.97%	11.71%
WECC-BC	11,738	11,738	13,869	13,869	13,869	18.15%	18.15%	18.15%	16.16%
TOTAL-CANADA	97,467	97,812	119,526	119,526	119,811	22.63%	22.63%	22.92%	10.00%
WECC-MEXW	1,532	1,532	2,617	2,617	2,617	70.84%	70.84%	70.84%	10.71%
TOTAL-MÉXICO	1,532	1,532	2,617	2,617	2,617	70.84%	70.84%	70.84%	10.71%
TOTAL-NERC	**745,513**	**777,889**	**1,092,828**	**1,120,688**	**1,131,207**	**46.59%**	**50.32%**	**51.74%**	**15.00%**

Demand, Resources, and Reserve Margins: 2015 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	71,692	73,054	76,006	76,006	76,751	6.02%	6.02%	7.06%	13.75%
FRCC	44,459	47,758	57,181	61,286	63,188	28.62%	37.85%	42.13%	15.00%
MISO	91,096	96,929	108,443	120,916	121,853	19.04%	32.73%	33.76%	16.30%
MRO-MAPP	5,135	5,230	6,430	6,430	6,430	25.21%	25.21%	25.21%	15.00%
NPCC-New England	27,193	28,840	34,997	34,997	35,510	28.70%	28.70%	30.59%	15.00%
NPCC-New York	34,151	34,151	42,077	42,077	42,209	23.21%	23.21%	23.59%	16.00%
PJM	149,968	163,168	180,473	180,473	188,445	20.34%	20.34%	25.66%	15.40%
SERC-E	42,750	44,903	52,658	52,658	52,672	23.18%	23.18%	23.21%	15.00%
SERC-N	44,952	47,303	55,142	59,061	59,061	22.67%	31.39%	31.39%	15.00%
SERC-SE	49,227	51,431	62,913	63,213	63,456	27.80%	28.41%	28.90%	15.00%
SERC-W	25,623	26,563	34,970	39,489	41,173	36.48%	54.12%	60.69%	15.00%
SPP	54,788	55,766	66,237	71,321	71,440	20.90%	30.17%	30.39%	13.60%
WECC-BASN	13,354	14,482	15,999	15,999	16,445	19.81%	19.81%	23.15%	12.60%
WECC-CALN	26,471	27,298	31,313	31,313	31,313	18.29%	18.29%	18.29%	14.71%
WECC-CALS	30,467	32,472	36,278	36,278	36,351	19.07%	19.07%	19.31%	15.14%
WECC-DSW	27,551	28,179	40,140	40,140	40,708	45.69%	45.69%	47.75%	13.50%
WECC-NORW	24,872	24,967	29,613	29,613	29,613	19.06%	19.06%	19.06%	17.90%
WECC-ROCK	11,827	12,330	14,165	14,165	14,172	19.77%	19.77%	19.83%	14.65%
TOTAL-UNITED STATES	775,577	814,823	945,034	975,433	990,788	21.85%	25.77%	27.75%	15.00%
MRO-Manitoba Hydro	3,207	3,207	4,944	4,944	4,944	54.15%	54.15%	54.15%	12.00%
MRO-SaskPower	3,444	3,535	3,840	3,840	3,840	11.51%	11.51%	11.51%	11.00%
NPCC-Maritimes	3,117	3,448	6,538	6,538	6,538	109.76%	109.76%	109.76%	20.00%
NPCC-Ontario	22,859	22,859	29,725	29,725	29,962	30.03%	30.03%	31.07%	19.80%
NPCC-Québec	21,642	21,642	32,489	32,489	32,489	50.12%	50.12%	50.12%	10.50%
WECC-AESO	12,039	12,077	14,613	14,613	14,613	21.38%	21.38%	21.38%	12.24%
WECC-BC	8,834	8,834	11,957	11,957	11,957	35.36%	35.36%	35.36%	12.51%
TOTAL-CANADA	75,142	75,602	104,107	104,107	104,344	38.55%	38.55%	38.86%	10.00%
WECC-MEXW	2,317	2,317	2,923	2,923	2,923	26.17%	26.17%	26.17%	11.86%
TOTAL-MÉXICO	2,317	2,317	2,923	2,923	2,923	26.17%	26.17%	26.17%	11.86%
TOTAL-NERC	**853,036**	**892,742**	**1,052,064**	**1,082,463**	**1,098,055**	**23.33%**	**26.90%**	**28.72%**	**15.00%**

Demand, Resources, and Reserve Margins: 2015/2016 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	53,378	54,972	78,473	78,473	81,845	47.01%	47.01%	53.33%	13.75%
FRCC	44,790	48,172	60,166	62,831	63,270	34.33%	40.28%	41.26%	15.00%
MISO	75,354	78,773	109,996	122,623	123,597	45.97%	62.73%	64.02%	16.30%
MRO-MAPP	5,074	5,074	6,840	6,840	6,840	34.82%	34.82%	34.82%	15.00%
NPCC-New England	21,193	22,825	37,531	37,531	38,259	77.09%	77.09%	80.53%	15.00%
NPCC-New York	25,053	25,053	41,480	41,480	43,325	65.57%	65.57%	72.93%	16.00%
PJM	123,711	136,911	180,744	180,744	188,715	46.10%	46.10%	52.55%	15.40%
SERC-E	42,934	44,520	55,091	55,091	55,105	28.32%	28.32%	28.35%	15.00%
SERC-N	44,685	47,166	68,909	72,900	72,900	54.21%	63.14%	63.14%	15.00%
SERC-SE	45,615	47,814	65,303	65,603	65,760	43.16%	43.82%	44.16%	15.00%
SERC-W	20,209	20,992	43,564	47,832	49,528	115.57%	136.69%	145.08%	15.00%
SPP	41,225	42,040	61,972	66,798	67,995	50.33%	62.04%	64.94%	13.60%
WECC-BASN	11,167	11,472	13,711	13,711	14,190	22.78%	22.78%	27.07%	13.49%
WECC-CALN	18,937	19,212	24,395	24,395	24,395	28.82%	28.82%	28.82%	11.86%
WECC-CALS	23,235	24,106	34,020	34,020	34,094	46.42%	46.42%	46.74%	11.03%
WECC-DSW	18,431	18,721	34,917	34,917	34,938	89.45%	89.45%	89.57%	13.96%
WECC-NORW	30,763	30,843	37,163	37,163	37,163	20.80%	20.80%	20.80%	19.90%
WECC-ROCK	9,918	10,189	13,244	13,244	13,637	33.54%	33.54%	37.50%	15.68%
TOTAL-UNITED STATES	655,672	688,855	967,521	996,199	1,015,559	47.56%	51.94%	54.89%	15.00%
MRO-Manitoba Hydro	4,723	4,723	6,106	6,106	6,106	29.28%	29.28%	29.28%	12.00%
MRO-SaskPower	3,859	3,950	4,377	4,377	4,377	13.43%	13.43%	13.43%	11.00%
NPCC-Maritimes	5,165	5,419	6,832	6,832	6,832	32.29%	32.29%	32.29%	20.00%
NPCC-Ontario	21,500	21,500	31,038	31,038	31,821	44.36%	44.36%	48.01%	19.20%
NPCC-Québec	38,527	38,527	43,197	43,197	43,197	12.12%	12.12%	12.12%	11.40%
WECC-AESO	12,801	12,801	17,568	17,568	17,568	37.24%	37.24%	37.24%	11.71%
WECC-BC	11,943	11,943	14,320	14,320	14,320	19.90%	19.90%	19.90%	16.16%
TOTAL-CANADA	98,517	98,863	123,438	123,438	124,221	25.30%	25.30%	26.09%	10.00%
WECC-MEXW	1,571	1,571	2,750	2,750	2,750	75.07%	75.07%	75.07%	10.71%
TOTAL-MÉXICO	1,571	1,571	2,750	2,750	2,750	75.07%	75.07%	75.07%	10.71%
TOTAL-NERC	**755,760**	**789,289**	**1,093,709**	**1,122,387**	**1,142,531**	**44.72%**	**48.51%**	**51.18%**	**15.00%**

Demand, Resources, and Reserve Margins: 2016 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	73,957	75,366	78,166	78,166	79,159	5.69%	5.69%	7.03%	13.75%
FRCC	45,242	48,594	56,591	60,718	62,643	25.08%	34.21%	38.46%	15.00%
MISO	91,556	97,811	108,564	121,037	121,974	18.58%	32.20%	33.22%	16.30%
MRO-MAPP	5,406	5,503	6,512	6,512	6,512	20.46%	20.46%	20.46%	15.00%
NPCC-New England	27,520	29,400	33,349	33,349	34,506	21.18%	21.18%	25.39%	15.00%
NPCC-New York	34,345	34,345	42,077	42,077	42,725	22.51%	22.51%	24.40%	16.00%
PJM	152,491	165,691	180,821	180,821	190,190	18.58%	18.58%	24.72%	15.40%
SERC-E	43,235	45,436	53,675	53,675	53,689	24.15%	24.15%	24.18%	15.00%
SERC-N	45,537	47,974	55,142	59,061	60,706	21.09%	29.70%	33.31%	15.00%
SERC-SE	49,823	52,045	65,326	65,626	65,868	31.12%	31.72%	32.20%	15.00%
SERC-W	25,937	26,881	35,171	39,690	41,476	35.60%	53.03%	59.91%	15.00%
SPP	55,368	56,364	66,084	71,167	71,287	19.35%	28.53%	28.75%	13.60%
WECC-BASN	13,607	14,765	16,067	16,067	16,834	18.08%	18.08%	23.72%	12.60%
WECC-CALN	27,072	27,904	31,406	31,406	31,408	16.01%	16.01%	16.02%	14.71%
WECC-CALS	30,796	32,821	36,535	36,535	36,713	18.63%	18.63%	19.21%	15.14%
WECC-DSW	28,035	28,679	41,473	41,473	42,100	47.93%	47.93%	50.17%	13.50%
WECC-NORW	25,155	25,270	30,917	30,917	30,918	22.91%	22.91%	22.91%	17.90%
WECC-ROCK	12,048	12,563	14,222	14,222	14,225	18.04%	18.04%	18.07%	14.65%
TOTAL-UNITED STATES	787,129	827,411	952,097	982,518	1,002,933	20.96%	24.82%	27.42%	15.00%
MRO-Manitoba Hydro	3,244	3,244	4,949	4,949	4,949	52.56%	52.56%	52.56%	12.00%
MRO-SaskPower	3,533	3,624	4,071	4,071	4,071	15.22%	15.22%	15.22%	11.00%
NPCC-Maritimes	3,110	3,441	6,542	6,542	6,542	110.34%	110.34%	110.34%	20.00%
NPCC-Ontario	22,638	22,638	28,801	28,801	29,455	27.22%	27.22%	30.11%	19.20%
NPCC-Québec	21,883	21,883	33,505	33,505	33,505	53.11%	53.11%	53.11%	11.40%
WECC-AESO	12,604	12,642	16,182	16,182	16,182	28.39%	28.39%	28.39%	12.24%
WECC-BC	8,913	8,913	11,909	11,909	11,909	33.62%	33.62%	33.62%	12.51%
TOTAL-CANADA	75,925	76,385	105,959	105,959	106,613	39.56%	39.56%	40.42%	10.00%
WECC-MEXW	2,374	2,374	2,924	2,924	3,264	23.16%	23.16%	37.50%	11.86%
TOTAL-MÉXICO	2,374	2,374	2,924	2,924	3,264	23.16%	23.16%	37.50%	11.86%
TOTAL-NERC	**865,428**	**906,170**	**1,060,979**	**1,091,401**	**1,112,810**	**22.60%**	**26.11%**	**28.58%**	**15.00%**

Demand, Resources, and Reserve Margins: 2016/2017 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	54,363	56,028	80,633	80,633	85,247	48.32%	48.32%	56.81%	13.75%
FRCC	45,297	48,797	61,167	64,260	65,126	35.04%	41.86%	43.77%	15.00%
MISO	75,854	79,521	110,117	122,744	123,718	45.17%	61.82%	63.10%	16.30%
MRO-MAPP	5,335	5,335	6,882	6,882	6,882	29.00%	29.00%	29.00%	15.00%
NPCC-New England	21,097	22,960	35,869	35,869	37,076	70.02%	70.02%	75.74%	15.00%
NPCC-New York	25,149	25,149	41,480	41,480	44,379	64.94%	64.94%	76.46%	16.00%
PJM	125,367	138,567	180,823	180,823	190,191	44.24%	44.24%	51.71%	15.40%
SERC-E	43,395	44,993	56,253	56,253	56,267	29.63%	29.63%	29.66%	15.00%
SERC-N	45,226	47,967	68,909	72,900	74,972	52.37%	61.19%	65.77%	15.00%
SERC-SE	46,266	48,485	67,652	67,952	68,109	46.22%	46.87%	47.21%	15.00%
SERC-W	20,694	21,493	43,765	48,033	49,831	111.49%	132.11%	140.80%	15.00%
SPP	41,812	42,644	61,891	66,717	67,895	48.02%	59.56%	62.38%	13.60%
WECC-BASN	11,416	11,721	13,204	13,204	13,982	15.67%	15.67%	22.48%	13.49%
WECC-CALN	19,220	19,498	23,350	23,350	23,351	21.49%	21.49%	21.50%	11.86%
WECC-CALS	23,441	24,332	32,805	32,805	32,984	39.95%	39.95%	40.71%	11.03%
WECC-DSW	18,827	19,117	35,197	35,197	35,613	86.95%	86.95%	89.16%	13.96%
WECC-NORW	31,053	31,148	38,188	38,188	38,189	22.98%	22.98%	22.98%	19.90%
WECC-ROCK	10,214	10,486	14,425	14,425	14,606	41.22%	41.22%	43.00%	15.68%
TOTAL-UNITED STATES	664,025	698,239	972,612	1,001,717	1,028,420	46.47%	50.86%	54.88%	15.00%
MRO-Manitoba Hydro	4,781	4,781	6,124	6,124	6,124	28.09%	28.09%	28.09%	12.00%
MRO-SaskPower	3,959	4,050	4,421	4,421	4,421	11.68%	11.68%	11.68%	11.00%
NPCC-Maritimes	5,185	5,444	6,838	6,838	6,838	31.88%	31.88%	31.88%	20.00%
NPCC-Ontario	21,153	21,153	28,332	28,332	29,197	33.94%	33.94%	38.02%	20.00%
NPCC-Québec	38,845	38,845	44,201	44,201	44,201	13.79%	13.79%	13.79%	12.20%
WECC-AESO	13,382	13,382	18,043	18,043	18,043	34.83%	34.83%	34.83%	11.71%
WECC-BC	12,050	12,050	14,466	14,466	14,466	20.05%	20.05%	20.05%	16.16%
TOTAL-CANADA	99,355	99,706	122,426	122,426	123,291	23.22%	23.22%	24.09%	10.00%
WECC-MEXW	1,610	1,610	2,902	2,902	3,243	80.27%	80.27%	101.41%	10.71%
TOTAL-MÉXICO	1,610	1,610	2,902	2,902	3,243	80.27%	80.27%	101.41%	10.71%
TOTAL-NERC	**764,990**	**799,555**	**1,097,940**	**1,127,045**	**1,154,953**	**43.52%**	**47.33%**	**50.98%**	**15.00%**

Demand, Resources, and Reserve Margins: 2017 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	75,360	76,821	78,166	78,166	79,159	3.72%	3.72%	5.04%	13.75%
FRCC	45,802	49,244	56,849	61,404	63,756	24.12%	34.06%	39.20%	15.00%
MISO	92,022	98,729	110,127	122,600	123,537	19.68%	33.23%	34.25%	16.30%
MRO-MAPP	5,461	5,560	6,514	6,514	6,514	19.28%	19.28%	19.28%	15.00%
NPCC-New England	27,797	29,895	33,324	33,324	34,531	19.88%	19.88%	24.23%	15.00%
NPCC-New York	34,550	34,550	42,077	42,077	42,800	21.79%	21.79%	23.88%	16.00%
PJM	154,233	167,433	180,821	180,821	191,470	17.24%	17.24%	24.14%	15.40%
SERC-E	43,707	45,939	53,720	53,720	53,734	22.91%	22.91%	22.94%	15.00%
SERC-N	45,987	48,660	55,142	59,061	60,891	19.91%	28.43%	32.41%	15.00%
SERC-SE	50,551	52,789	66,278	66,578	66,820	31.11%	31.70%	32.18%	15.00%
SERC-W	26,252	27,199	35,171	39,690	41,579	33.98%	51.19%	58.38%	15.00%
SPP	55,927	57,055	66,889	71,973	72,091	19.60%	28.69%	28.90%	13.60%
WECC-BASN	13,923	15,081	16,054	16,054	16,822	15.30%	15.30%	20.82%	12.60%
WECC-CALN	27,376	28,211	31,403	31,403	31,405	14.71%	14.71%	14.72%	14.71%
WECC-CALS	31,191	33,254	36,723	36,723	36,931	17.74%	17.74%	18.40%	15.14%
WECC-DSW	28,510	29,157	41,917	41,917	42,778	47.03%	47.03%	50.05%	13.50%
WECC-NORW	25,445	25,560	30,499	30,499	30,500	19.86%	19.86%	19.87%	17.90%
WECC-ROCK	12,235	12,763	14,094	14,094	14,099	15.20%	15.20%	15.24%	14.65%
TOTAL-UNITED STATES	796,328	837,899	955,768	986,617	1,009,416	20.02%	23.90%	26.76%	15.00%
MRO-Manitoba Hydro	3,286	3,286	4,949	4,949	4,949	50.60%	50.60%	50.60%	12.00%
MRO-SaskPower	3,630	3,721	4,285	4,285	4,285	18.02%	18.02%	18.02%	11.00%
NPCC-Maritimes	3,116	3,447	6,547	6,547	6,547	110.09%	110.09%	110.09%	20.00%
NPCC-Ontario	22,471	22,471	26,937	26,937	27,657	19.88%	19.88%	23.08%	20.00%
NPCC-Québec	22,008	22,008	33,911	33,911	33,911	54.08%	54.08%	54.08%	12.20%
WECC-AESO	13,108	13,146	15,962	15,962	15,962	21.77%	21.77%	21.77%	12.24%
WECC-BC	9,043	9,043	11,920	11,920	11,920	31.81%	31.81%	31.81%	12.51%
TOTAL-CANADA	76,663	77,123	104,510	104,510	105,230	36.32%	36.32%	37.26%	10.00%
WECC-MEXW	2,431	2,431	2,924	2,924	3,264	20.27%	20.27%	34.27%	11.86%
TOTAL-MÉXICO	2,431	2,431	2,924	2,924	3,264	20.27%	20.27%	34.27%	11.86%
TOTAL-NERC	**875,421**	**917,453**	**1,063,202**	**1,094,051**	**1,117,910**	**21.45%**	**24.97%**	**27.70%**	**15.00%**

Demand, Resources, and Reserve Margins: 2017/2018 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	57,204	58,869	80,633	80,633	85,247	40.96%	40.96%	49.02%	13.75%
FRCC	45,752	49,298	61,238	64,346	65,227	33.85%	40.64%	42.57%	15.00%
MISO	76,172	80,104	111,680	124,307	125,281	46.61%	63.19%	64.47%	16.30%
MRO-MAPP	5,412	5,412	6,884	6,884	6,884	27.20%	27.20%	27.20%	15.00%
NPCC-New England	21,011	23,090	35,869	35,869	37,076	70.71%	70.71%	76.46%	15.00%
NPCC-New York	25,153	25,153	41,480	41,480	44,379	64.91%	64.91%	76.44%	16.00%
PJM	126,462	139,662	180,831	180,831	191,479	42.99%	42.99%	51.41%	15.40%
SERC-E	43,879	45,487	56,253	56,253	56,267	28.20%	28.20%	28.23%	15.00%
SERC-N	45,723	48,659	68,909	72,900	74,972	50.71%	59.44%	63.97%	15.00%
SERC-SE	46,743	48,978	68,641	68,941	69,098	46.85%	47.49%	47.83%	15.00%
SERC-W	21,106	21,908	43,765	48,033	49,934	107.36%	127.58%	136.59%	15.00%
SPP	42,205	43,069	62,716	67,543	68,724	48.60%	60.04%	62.83%	13.60%
WECC-BASN	11,640	11,945	13,362	13,362	14,140	14.79%	14.79%	21.47%	13.49%
WECC-CALN	19,409	19,689	24,156	24,156	24,158	24.46%	24.46%	24.47%	11.86%
WECC-CALS	23,770	24,697	32,984	32,984	33,192	38.76%	38.76%	39.64%	11.03%
WECC-DSW	19,187	19,477	35,299	35,299	35,928	83.98%	83.98%	87.25%	13.96%
WECC-NORW	31,355	31,450	37,735	37,735	37,735	20.35%	20.35%	20.35%	19.90%
WECC-ROCK	10,398	10,672	14,882	14,882	15,160	43.12%	43.12%	45.80%	15.68%
TOTAL-UNITED STATES	672,581	707,619	977,319	1,006,439	1,034,881	45.31%	49.64%	53.87%	15.00%
MRO-Manitoba Hydro	4,845	4,845	6,124	6,124	6,124	26.39%	26.39%	26.39%	12.00%
MRO-SaskPower	4,068	4,159	4,701	4,701	4,701	15.57%	15.57%	15.57%	11.00%
NPCC-Maritimes	5,201	5,462	6,846	6,846	6,846	31.63%	31.63%	31.63%	20.00%
NPCC-Ontario	20,719	20,719	28,121	28,121	29,886	35.73%	35.73%	44.25%	20.00%
NPCC-Québec	39,189	39,189	44,817	44,817	44,817	14.36%	14.36%	14.36%	12.20%
WECC-AESO	13,856	13,856	18,755	18,755	18,755	35.36%	35.36%	35.36%	11.71%
WECC-BC	12,073	12,073	14,419	14,419	14,419	19.44%	19.44%	19.44%	16.16%
TOTAL-CANADA	99,951	100,303	123,785	123,785	125,550	23.85%	23.85%	25.61%	10.00%
WECC-MEXW	1,648	1,648	2,901	2,901	3,241	76.03%	76.03%	96.69%	10.71%
TOTAL-MÉXICO	1,648	1,648	2,901	2,901	3,241	76.03%	76.03%	96.69%	10.71%
TOTAL-NERC	**774,180**	**809,570**	**1,104,004**	**1,133,124**	**1,163,672**	**42.60%**	**46.36%**	**50.31%**	**15.00%**

Demand, Resources, and Reserve Margins: 2018 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	76,483	78,002	79,406	79,406	80,569	3.82%	3.82%	5.34%	13.75%
FRCC	46,152	49,643	56,921	61,491	63,858	23.33%	33.24%	38.36%	15.00%
MISO	92,447	99,611	110,152	122,624	123,561	19.15%	32.64%	33.66%	16.30%
MRO-MAPP	5,543	5,643	6,516	6,516	6,516	17.57%	17.57%	17.57%	15.00%
NPCC-New England	27,973	30,275	33,324	33,324	34,531	19.13%	19.13%	23.44%	15.00%
NPCC-New York	34,868	34,868	42,077	42,077	42,800	20.68%	20.68%	22.75%	16.00%
PJM	155,832	169,032	180,829	180,829	192,121	16.04%	16.04%	23.29%	15.40%
SERC-E	44,103	46,358	53,720	53,720	53,734	21.80%	21.80%	21.84%	15.00%
SERC-N	46,504	49,288	55,142	59,061	61,671	18.57%	27.00%	32.61%	15.00%
SERC-SE	51,023	53,256	66,269	66,569	66,812	29.88%	30.47%	30.94%	15.00%
SERC-W	26,556	27,505	35,171	39,690	42,281	32.44%	49.46%	59.22%	15.00%
SPP	56,539	57,591	66,913	71,997	72,115	18.35%	27.34%	27.55%	13.60%
WECC-BASN	14,148	15,306	16,037	16,037	16,805	13.35%	13.35%	18.78%	12.60%
WECC-CALN	27,670	28,507	31,413	31,413	31,415	13.53%	13.53%	13.54%	14.71%
WECC-CALS	31,577	33,666	36,382	36,382	36,691	15.22%	15.22%	16.19%	15.14%
WECC-DSW	29,106	29,686	42,514	42,514	43,327	46.07%	46.07%	48.86%	13.50%
WECC-NORW	25,675	25,797	30,331	30,331	30,333	18.14%	18.14%	18.14%	17.90%
WECC-ROCK	12,431	12,970	14,094	14,094	14,108	13.38%	13.38%	13.49%	14.65%
TOTAL-UNITED STATES	804,630	847,005	957,212	988,076	1,013,248	18.96%	22.80%	25.93%	15.00%
MRO-Manitoba Hydro	3,221	3,221	4,949	4,949	4,949	53.66%	53.66%	53.66%	12.00%
MRO-SaskPower	3,618	3,709	4,285	4,285	4,285	18.41%	18.41%	18.41%	11.00%
NPCC-Maritimes	3,128	3,459	6,558	6,558	6,558	109.65%	109.65%	109.65%	20.00%
NPCC-Ontario	22,583	22,583	25,858	25,858	28,368	14.50%	14.50%	25.62%	20.00%
NPCC-Québec	22,125	22,125	34,764	34,764	34,764	57.13%	57.13%	57.13%	12.20%
WECC-AESO	13,522	13,560	15,929	15,929	15,929	17.80%	17.80%	17.80%	12.24%
WECC-BC	9,167	9,167	12,470	12,470	12,470	36.03%	36.03%	36.03%	12.51%
TOTAL-CANADA	77,364	77,824	104,813	104,813	107,322	35.48%	35.48%	38.72%	10.00%
WECC-MEXW	2,488	2,488	2,923	2,923	3,264	17.50%	17.50%	31.18%	11.86%
TOTAL-MÉXICO	2,488	2,488	2,923	2,923	3,264	17.50%	17.50%	31.18%	11.86%
TOTAL-NERC	**884,482**	**927,317**	**1,064,948**	**1,095,812**	**1,123,834**	**20.40%**	**23.89%**	**27.06%**	**15.00%**

Demand, Resources, and Reserve Margins: 2018/2019 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	57,459	59,202	81,873	81,873	87,337	42.49%	42.49%	52.00%	13.75%
FRCC	46,305	49,908	61,461	64,844	66,001	32.73%	40.04%	42.54%	15.00%
MISO	76,692	80,891	111,704	124,331	125,306	45.65%	62.12%	63.39%	16.30%
MRO-MAPP	5,522	5,522	6,886	6,886	6,886	24.70%	24.70%	24.70%	15.00%
NPCC-New England	20,929	23,210	35,869	35,869	37,076	71.38%	71.38%	77.15%	15.00%
NPCC-New York	25,265	25,265	41,480	41,480	44,379	64.18%	64.18%	75.65%	16.00%
PJM	127,644	140,844	182,401	182,401	193,693	42.90%	42.90%	51.74%	15.40%
SERC-E	44,382	46,003	56,343	56,343	56,357	26.95%	26.95%	26.98%	15.00%
SERC-N	46,176	49,266	68,909	72,900	75,852	49.23%	57.88%	64.27%	15.00%
SERC-SE	47,434	49,665	68,526	68,826	68,983	44.46%	45.10%	45.43%	15.00%
SERC-W	21,410	22,215	43,765	48,033	51,156	104.42%	124.35%	138.94%	15.00%
SPP	42,726	43,590	62,960	67,787	69,138	47.36%	58.65%	61.82%	13.60%
WECC-BASN	11,818	12,123	13,896	13,896	14,678	17.58%	17.58%	24.20%	13.49%
WECC-CALN	19,618	19,898	24,309	24,309	24,505	23.91%	23.91%	24.91%	11.86%
WECC-CALS	24,099	25,051	33,789	33,789	34,098	40.21%	40.21%	41.49%	11.03%
WECC-DSW	19,540	19,830	35,713	35,713	36,341	82.77%	82.77%	85.98%	13.96%
WECC-NORW	31,607	31,705	38,343	38,343	38,344	21.31%	21.31%	21.31%	19.90%
WECC-ROCK	10,602	10,877	14,578	14,578	15,074	37.50%	37.50%	42.18%	15.68%
TOTAL-UNITED STATES	679,228	715,065	982,805	1,012,200	1,045,206	44.69%	49.02%	53.88%	15.00%
MRO-Manitoba Hydro	4,801	4,801	6,124	6,124	6,124	27.56%	27.56%	27.56%	12.00%
MRO-SaskPower	4,054	4,145	4,701	4,701	4,701	15.97%	15.97%	15.97%	11.00%
NPCC-Maritimes	5,226	5,489	6,861	6,861	6,861	31.28%	31.28%	31.28%	20.00%
NPCC-Ontario	20,700	20,700	27,189	27,189	30,150	31.35%	31.35%	45.65%	20.00%
NPCC-Québec	39,487	39,487	45,399	45,399	45,399	14.97%	14.97%	14.97%	12.20%
WECC-AESO	14,351	14,351	18,081	18,081	18,081	25.99%	25.99%	25.99%	11.71%
WECC-BC	12,223	12,223	14,409	14,409	14,409	17.88%	17.88%	17.88%	16.16%
TOTAL-CANADA	100,842	101,196	122,764	122,764	125,725	21.74%	21.74%	24.68%	10.00%
WECC-MEXW	1,687	1,687	2,649	2,649	2,989	57.02%	57.02%	77.20%	10.71%
TOTAL-MÉXICO	1,687	1,687	2,649	2,649	2,989	57.02%	57.02%	77.20%	10.71%
TOTAL-NERC	**781,757**	**817,948**	**1,108,218**	**1,137,614**	**1,173,920**	**41.76%**	**45.52%**	**50.16%**	**15.00%**

Demand, Resources, and Reserve Margins: 2019 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	76,769	78,351	78,556	78,556	79,719	2.33%	2.33%	3.84%	13.75%
FRCC	46,803	50,356	57,848	62,693	65,337	23.60%	33.95%	39.60%	15.00%
MISO	92,932	100,565	110,152	122,624	123,561	18.53%	31.95%	32.96%	16.30%
MRO-MAPP	5,643	5,746	6,518	6,518	6,518	15.50%	15.50%	15.50%	15.00%
NPCC-New England	28,111	30,605	33,324	33,324	34,531	18.54%	18.54%	22.84%	15.00%
NPCC-New York	35,204	35,204	42,077	42,077	42,838	19.52%	19.52%	21.68%	16.00%
PJM	157,660	170,860	182,399	182,399	193,691	15.69%	15.69%	22.85%	15.40%
SERC-E	44,636	46,908	55,103	55,103	55,117	23.45%	23.45%	23.48%	15.00%
SERC-N	47,044	50,090	55,142	59,061	62,451	17.21%	25.54%	32.75%	15.00%
SERC-SE	51,707	53,948	66,154	66,454	66,696	27.94%	28.52%	28.99%	15.00%
SERC-W	26,910	27,863	35,171	39,690	43,580	30.70%	47.49%	61.95%	15.00%
SPP	57,338	58,378	66,970	72,054	72,189	16.80%	25.67%	25.90%	13.60%
WECC-BASN	14,392	15,550	15,895	15,895	16,667	10.44%	10.44%	15.80%	12.60%
WECC-CALN	27,998	28,834	30,534	30,534	30,536	9.06%	9.06%	9.07%	14.71%
WECC-CALS	31,948	34,090	36,810	36,810	37,129	15.22%	15.22%	16.22%	15.14%
WECC-DSW	29,622	30,204	41,934	41,934	43,162	41.56%	41.56%	45.71%	13.50%
WECC-NORW	25,901	26,034	30,600	30,600	30,602	18.14%	18.14%	18.15%	17.90%
WECC-ROCK	12,626	13,176	14,247	14,247	14,263	12.84%	12.84%	12.97%	14.65%
TOTAL-UNITED STATES	813,244	856,761	959,432	990,572	1,018,587	17.98%	21.81%	25.25%	15.00%
MRO-Manitoba Hydro	3,271	3,271	4,852	4,852	4,852	48.34%	48.34%	48.34%	12.00%
MRO-SaskPower	3,665	3,756	4,285	4,285	4,285	16.89%	16.89%	16.89%	11.00%
NPCC-Maritimes	3,140	3,471	6,558	6,558	6,558	108.84%	108.84%	108.84%	20.00%
NPCC-Ontario	22,891	22,891	24,777	24,777	27,827	8.24%	8.24%	21.57%	20.00%
NPCC-Québec	22,307	22,307	34,799	34,799	34,799	56.00%	56.00%	56.00%	12.20%
WECC-AESO	13,936	13,974	15,669	15,669	15,669	12.43%	12.43%	12.43%	12.24%
WECC-BC	9,289	9,289	12,369	12,369	12,369	33.16%	33.16%	33.16%	12.51%
TOTAL-CANADA	78,498	78,958	103,308	103,308	106,359	31.61%	31.61%	35.49%	10.00%
WECC-MEXW	2,545	2,545	2,923	2,923	3,535	14.86%	14.86%	38.90%	11.86%
TOTAL-MÉXICO	2,545	2,545	2,923	2,923	3,535	14.86%	14.86%	38.90%	11.86%
TOTAL-NERC	**894,287**	**938,265**	**1,065,664**	**1,096,804**	**1,128,480**	**19.16%**	**22.65%**	**26.19%**	**15.00%**

Demand, Resources, and Reserve Margins: 2019/2020 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	57,575	59,318	81,013	81,013	86,477	40.71%	40.71%	50.20%	13.75%
FRCC	46,910	50,570	62,340	65,725	66,884	32.89%	40.11%	42.58%	15.00%
MISO	77,174	81,649	111,704	124,331	125,306	44.74%	61.10%	62.37%	16.30%
MRO-MAPP	5,623	5,623	6,866	6,866	6,866	22.11%	22.11%	22.11%	15.00%
NPCC-New England	20,859	23,330	35,869	35,869	37,076	71.96%	71.96%	77.75%	15.00%
NPCC-New York	25,422	25,422	41,480	41,480	44,757	63.17%	63.17%	76.06%	16.00%
PJM	128,818	142,018	182,401	182,401	193,693	41.60%	41.60%	50.36%	15.40%
SERC-E	45,016	46,648	57,661	57,661	57,675	28.09%	28.09%	28.12%	15.00%
SERC-N	46,697	49,932	68,909	72,900	76,732	47.57%	56.11%	64.32%	15.00%
SERC-SE	48,097	50,338	68,506	68,806	68,964	42.43%	43.06%	43.38%	15.00%
SERC-W	21,118	21,923	43,765	48,033	51,975	107.24%	127.45%	146.12%	15.00%
SPP	43,360	44,223	63,127	67,954	69,307	45.59%	56.72%	59.84%	13.60%
WECC-BASN	11,940	12,245	13,935	13,935	14,919	16.71%	16.71%	24.94%	13.49%
WECC-CALN	19,767	20,048	24,348	24,348	24,544	23.18%	23.18%	24.17%	11.86%
WECC-CALS	24,438	25,440	32,161	32,161	32,470	31.60%	31.60%	32.87%	11.03%
WECC-DSW	19,945	20,235	35,184	35,184	36,614	76.41%	76.41%	83.57%	13.96%
WECC-NORW	31,862	31,971	37,851	37,851	37,852	18.80%	18.80%	18.80%	19.90%
WECC-ROCK	10,796	11,072	14,612	14,612	15,140	35.35%	35.35%	40.23%	15.68%
TOTAL-UNITED STATES	685,417	722,005	981,734	1,011,131	1,047,251	43.23%	47.52%	52.79%	15.00%
MRO-Manitoba Hydro	4,878	4,878	6,027	6,027	6,027	23.55%	23.55%	23.55%	12.00%
MRO-SaskPower	4,107	4,198	4,701	4,701	4,701	14.47%	14.47%	14.47%	11.00%
NPCC-Maritimes	5,228	5,492	6,861	6,861	6,861	31.25%	31.25%	31.25%	20.00%
NPCC-Ontario	21,063	21,063	25,160	25,160	28,528	19.45%	19.45%	35.44%	20.00%
NPCC-Québec	39,812	39,812	45,505	45,505	45,505	14.30%	14.30%	14.30%	12.20%
WECC-AESO	14,759	14,759	18,140	18,140	18,140	22.91%	22.91%	22.91%	11.71%
WECC-BC	12,373	12,373	14,474	14,474	14,474	16.98%	16.98%	16.98%	16.16%
TOTAL-CANADA	102,219	102,575	120,869	120,869	124,237	18.24%	18.24%	21.54%	10.00%
WECC-MEXW	1,725	1,725	2,774	2,774	3,386	60.83%	60.83%	96.29%	10.71%
TOTAL-MÉXICO	1,725	1,725	2,774	2,774	3,386	60.83%	60.83%	96.29%	10.71%
TOTAL-NERC	**789,361**	**826,305**	**1,105,377**	**1,134,775**	**1,174,874**	**40.03%**	**43.76%**	**48.84%**	**15.00%**

Demand, Resources, and Reserve Margins: 2020 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	78,524	80,176	78,556	78,556	79,719	0.04%	0.04%	1.52%	13.75%
FRCC	47,581	51,191	57,847	62,695	65,339	21.58%	31.76%	37.32%	15.00%
MISO	93,419	101,530	110,152	122,624	123,561	17.91%	31.26%	32.27%	16.30%
MRO-MAPP	5,735	5,840	6,518	6,518	6,518	13.65%	13.65%	13.65%	15.00%
NPCC-New England	28,257	30,930	33,324	33,324	34,531	17.93%	17.93%	22.20%	15.00%
NPCC-New York	35,526	35,526	42,077	42,077	42,838	18.44%	18.44%	20.58%	16.00%
PJM	159,593	172,793	182,399	182,399	193,691	14.29%	14.29%	21.37%	15.40%
SERC-E	45,200	47,487	55,379	55,379	55,393	22.52%	22.52%	22.55%	15.00%
SERC-N	47,653	50,868	56,402	60,321	63,711	18.36%	26.58%	33.70%	15.00%
SERC-SE	52,396	54,645	66,135	66,435	66,865	26.22%	26.79%	27.61%	15.00%
SERC-W	27,198	28,153	35,171	39,690	43,730	29.32%	45.93%	60.79%	15.00%
SPP	57,971	59,239	67,496	72,580	72,737	16.43%	25.20%	25.47%	13.60%
WECC-BASN	14,628	15,786	15,719	15,719	16,685	7.46%	7.46%	14.07%	12.60%
WECC-CALN	28,324	29,160	31,011	31,011	31,014	9.49%	9.49%	9.49%	14.71%
WECC-CALS	32,472	34,666	37,485	37,485	37,909	15.44%	15.44%	16.74%	15.14%
WECC-DSW	30,183	30,764	40,664	40,664	42,234	34.72%	34.72%	39.93%	13.50%
WECC-NORW	26,151	26,295	30,895	30,895	30,895	18.14%	18.14%	18.14%	17.90%
WECC-ROCK	12,840	13,404	14,837	14,837	14,842	15.56%	15.56%	15.59%	14.65%
TOTAL-UNITED STATES	823,652	868,453	962,068	993,209	1,022,214	16.81%	20.59%	24.11%	15.00%
MRO-Manitoba Hydro	3,348	3,348	4,602	4,602	5,232	37.45%	37.45%	56.26%	12.00%
MRO-SaskPower	3,716	3,807	4,285	4,285	4,285	15.29%	15.29%	15.29%	11.00%
NPCC-Maritimes	3,163	3,494	6,558	6,558	6,558	107.33%	107.33%	107.33%	20.00%
NPCC-Ontario	23,010	23,010	23,867	23,867	28,509	3.72%	3.72%	23.90%	20.00%
NPCC-Québec	22,503	22,503	34,905	34,905	34,905	55.11%	55.11%	55.11%	12.20%
WECC-AESO	14,336	14,374	15,619	15,619	15,619	8.95%	8.95%	8.95%	12.24%
WECC-BC	9,427	9,427	11,626	11,626	11,626	23.33%	23.33%	23.33%	12.51%
TOTAL-CANADA	79,504	79,964	101,461	101,461	106,734	27.62%	27.62%	34.25%	10.00%
WECC-MEXW	2,602	2,602	2,923	2,923	3,535	12.35%	12.35%	35.85%	11.86%
TOTAL-MÉXICO	2,602	2,602	2,923	2,923	3,535	12.35%	12.35%	35.85%	11.86%
TOTAL-NERC	**905,758**	**951,019**	**1,066,452**	**1,097,594**	**1,132,482**	**17.74%**	**21.18%**	**25.03%**	**15.00%**

Demand, Resources, and Reserve Margins: 2020/2021 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	58,210	60,039	81,330	81,330	86,794	39.72%	39.72%	49.10%	13.75%
FRCC	47,509	51,218	63,335	66,720	67,879	33.31%	40.44%	42.88%	15.00%
MISO	77,498	82,252	111,704	124,331	125,306	44.14%	60.43%	61.69%	16.30%
MRO-MAPP	5,718	5,718	6,866	6,866	6,866	20.07%	20.07%	20.07%	15.00%
NPCC-New England	20,797	23,445	35,863	35,863	37,070	72.44%	72.44%	78.25%	15.00%
NPCC-New York	25,627	25,627	41,480	41,480	44,757	61.86%	61.86%	74.65%	16.00%
PJM	130,219	143,419	182,401	182,401	193,693	40.07%	40.07%	48.74%	15.40%
SERC-E	45,557	47,201	57,942	57,942	57,956	27.19%	27.19%	27.22%	15.00%
SERC-N	47,211	50,584	70,169	74,160	77,992	48.63%	57.08%	65.20%	15.00%
SERC-SE	48,943	51,193	68,499	68,799	69,144	39.96%	40.57%	41.28%	15.00%
SERC-W	21,726	22,539	43,765	48,033	52,125	101.44%	121.09%	139.92%	15.00%
SPP	43,930	44,794	63,774	68,600	70,175	45.17%	56.16%	59.74%	13.60%
WECC-BASN	12,026	12,331	13,968	13,968	15,128	16.15%	16.15%	25.79%	13.49%
WECC-CALN	19,919	20,198	23,971	23,971	24,165	20.34%	20.34%	21.32%	11.86%
WECC-CALS	24,941	25,994	30,223	30,223	30,637	21.18%	21.18%	22.84%	11.03%
WECC-DSW	20,263	20,553	36,364	36,364	38,149	79.46%	79.46%	88.27%	13.96%
WECC-NORW	32,075	32,195	37,625	37,625	37,626	17.30%	17.30%	17.31%	19.90%
WECC-ROCK	10,922	11,200	13,156	13,156	13,581	20.45%	20.45%	24.35%	15.68%
TOTAL-UNITED STATES	693,092	730,501	982,436	1,011,834	1,049,044	41.75%	45.99%	51.36%	15.00%
MRO-Manitoba Hydro	4,981	4,981	5,777	5,777	6,317	15.97%	15.97%	26.81%	12.00%
MRO-SaskPower	4,164	4,255	4,701	4,701	4,701	12.91%	12.91%	12.91%	11.00%
NPCC-Maritimes	5,247	5,513	6,861	6,861	6,861	30.75%	30.75%	30.75%	20.00%
NPCC-Ontario	21,234	21,234	25,125	25,125	30,085	18.33%	18.33%	41.69%	20.00%
NPCC-Québec	40,079	40,079	45,906	45,906	45,906	14.54%	14.54%	14.54%	12.20%
WECC-AESO	15,162	15,162	18,746	18,746	18,746	23.64%	23.64%	23.64%	11.71%
WECC-BC	12,523	12,523	14,330	14,330	14,330	14.43%	14.43%	14.43%	16.16%
TOTAL-CANADA	103,391	103,747	121,446	121,446	126,946	17.46%	17.46%	22.78%	10.00%
WECC-MEXW	1,764	1,764	2,770	2,770	3,382	57.05%	57.05%	91.72%	10.71%
TOTAL-MÉXICO	1,764	1,764	2,770	2,770	3,382	57.05%	57.05%	91.72%	10.71%
TOTAL-NERC	**798,246**	**836,012**	**1,106,653**	**1,136,050**	**1,179,373**	**38.64%**	**42.32%**	**47.75%**	**15.00%**

Demand, Resources, and Reserve Margins: 2021 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	79,682	81,410	78,873	78,873	80,036	-1.02%	-1.02%	0.44%	13.75%
FRCC	48,273	51,933	59,941	65,247	68,351	24.17%	35.16%	41.59%	15.00%
MISO	93,957	102,559	110,152	122,624	123,561	17.24%	30.51%	31.51%	16.30%
MRO-MAPP	5,821	5,928	6,518	6,518	6,518	11.97%	11.97%	11.97%	15.00%
NPCC-New England	28,414	31,255	33,318	33,318	34,525	17.26%	17.26%	21.51%	15.00%
NPCC-New York	35,913	35,913	42,077	42,077	42,838	17.16%	17.16%	19.28%	16.00%
PJM	161,438	174,638	182,399	182,399	193,691	12.98%	12.98%	19.98%	15.40%
SERC-E	45,848	48,149	56,007	56,007	56,021	22.16%	22.16%	22.19%	15.00%
SERC-N	48,167	51,345	56,402	60,321	64,491	17.10%	25.23%	33.89%	15.00%
SERC-SE	53,343	55,600	65,848	66,148	66,579	23.44%	24.01%	24.81%	15.00%
SERC-W	27,472	28,435	35,450	39,969	44,759	29.04%	45.49%	62.93%	15.00%
SPP	58,716	59,904	67,715	72,799	72,956	15.33%	23.98%	24.25%	13.60%
WECC-BASN	14,836	15,994	15,814	15,814	16,779	6.59%	6.59%	13.10%	12.60%
WECC-CALN	28,652	29,487	31,293	31,293	31,295	9.22%	9.22%	9.22%	14.71%
WECC-CALS	32,997	35,243	38,010	38,010	38,434	15.19%	15.19%	16.48%	15.14%
WECC-DSW	30,720	31,305	39,790	39,790	41,441	29.52%	29.52%	34.90%	13.50%
WECC-NORW	26,414	26,561	31,204	31,204	31,206	18.13%	18.13%	18.14%	17.90%
WECC-ROCK	13,093	13,615	14,656	14,656	14,660	11.94%	11.94%	11.97%	14.65%
TOTAL-UNITED STATES	833,758	879,275	965,464	997,065	1,028,141	15.80%	19.59%	23.31%	15.00%
MRO-Manitoba Hydro	3,428	3,428	4,377	4,377	5,007	27.69%	27.69%	46.06%	12.00%
MRO-SaskPower	3,784	3,875	4,394	4,394	4,394	16.11%	16.11%	16.11%	11.00%
NPCC-Maritimes	3,175	3,506	6,558	6,558	6,558	106.54%	106.54%	106.54%	20.00%
NPCC-Ontario	23,390	23,390	22,787	22,787	28,820	-2.58%	-2.58%	23.21%	20.00%
NPCC-Québec	22,662	22,662	35,306	35,306	35,306	55.79%	55.79%	55.79%	12.20%
WECC-AESO	14,727	14,765	15,621	15,621	15,621	6.07%	6.07%	6.07%	12.24%
WECC-BC	9,553	9,553	10,983	10,983	10,983	14.97%	14.97%	14.97%	12.51%
TOTAL-CANADA	80,719	81,179	100,027	100,027	106,689	23.92%	23.92%	32.17%	10.00%
WECC-MEXW	2,659	2,659	2,923	2,923	3,535	9.94%	9.94%	32.94%	11.86%
TOTAL-MÉXICO	2,659	2,659	2,923	2,923	3,535	9.94%	9.94%	32.94%	11.86%
TOTAL-NERC	**917,136**	**963,113**	**1,068,414**	**1,100,015**	**1,138,365**	**16.49%**	**19.94%**	**24.12%**	**15.00%**

Demand, Resources, and Reserve Margins: 2021/2022 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	59,031	60,917	81,330	81,330	86,794	37.78%	37.78%	47.03%	13.75%
FRCC	48,169	51,921	64,893	68,824	70,529	34.72%	42.88%	46.42%	15.00%
MISO	78,022	83,064	111,704	124,331	125,306	43.17%	59.35%	60.60%	16.30%
MRO-MAPP	5,814	5,814	6,866	6,866	6,866	18.10%	18.10%	18.10%	15.00%
NPCC-New England	20,750	23,565	35,863	35,863	37,070	72.83%	72.83%	78.65%	15.00%
NPCC-New York	25,794	25,794	42,833	42,833	46,110	66.06%	66.06%	78.76%	16.00%
PJM	131,636	144,836	182,401	182,401	193,693	38.56%	38.56%	47.14%	15.40%
SERC-E	46,144	47,797	58,720	58,720	58,734	27.25%	27.25%	27.28%	15.00%
SERC-N	47,891	51,397	70,169	74,160	78,872	46.52%	54.85%	64.69%	15.00%
SERC-SE	49,770	52,029	68,113	68,413	68,758	36.86%	37.46%	38.15%	15.00%
SERC-W	21,891	22,707	44,044	48,312	53,154	101.20%	120.69%	142.81%	15.00%
SPP	44,470	45,334	63,966	68,793	70,368	43.84%	54.69%	58.24%	13.60%
WECC-BASN	12,158	12,463	13,565	13,565	14,792	11.57%	11.57%	21.67%	13.49%
WECC-CALN	20,070	20,348	23,848	23,848	23,946	18.82%	18.82%	19.31%	11.86%
WECC-CALS	25,300	26,403	32,182	32,182	32,596	27.20%	27.20%	28.84%	11.03%
WECC-DSW	20,490	20,780	36,572	36,572	37,479	78.49%	78.49%	82.91%	13.96%
WECC-NORW	32,391	32,512	37,468	37,468	37,470	15.67%	15.67%	15.68%	19.90%
WECC-ROCK	11,165	11,401	14,162	14,162	14,586	26.85%	26.85%	30.64%	15.68%
TOTAL-UNITED STATES	700,956	739,081	988,701	1,018,645	1,057,124	41.05%	45.32%	50.81%	15.00%
MRO-Manitoba Hydro	5,089	5,089	5,552	5,552	6,182	9.10%	9.10%	21.48%	12.00%
MRO-SaskPower	4,239	4,330	4,828	4,828	4,828	13.90%	13.90%	13.90%	11.00%
NPCC-Maritimes	5,264	5,530	6,861	6,861	6,861	30.34%	30.34%	30.34%	20.00%
NPCC-Ontario	21,441	21,441	26,014	26,014	32,364	21.33%	21.33%	50.95%	20.00%
NPCC-Québec	40,317	40,317	45,906	45,906	45,906	13.86%	13.86%	13.86%	12.20%
WECC-AESO	15,618	15,618	18,034	18,034	18,034	15.47%	15.47%	15.47%	11.71%
WECC-BC	12,673	12,673	14,401	14,401	14,401	13.64%	13.64%	13.64%	16.16%
TOTAL-CANADA	104,640	104,997	121,597	121,597	128,577	16.21%	16.21%	22.88%	10.00%
WECC-MEXW	1,803	1,803	2,771	2,771	3,382	53.67%	53.67%	87.59%	10.71%
TOTAL-MÉXICO	1,803	1,803	2,771	2,771	3,382	53.67%	53.67%	87.59%	10.71%
TOTAL-NERC	**807,399**	**845,882**	**1,113,069**	**1,143,013**	**1,189,083**	**37.86%**	**41.57%**	**47.27%**	**15.00%**

Demand, Resources, and Reserve Margins: 2022 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	80,694	82,507	78,873	78,873	80,036	-2.26%	-2.26%	-0.82%	13.75%
FRCC	48,923	52,583	60,203	65,509	68,613	23.06%	33.90%	40.25%	15.00%
MISO	94,875	103,584	110,152	122,624	123,561	16.10%	29.25%	30.24%	16.30%
MRO-MAPP	5,906	6,015	6,518	6,518	6,518	10.36%	10.36%	10.36%	15.00%
NPCC-New England	28,583	31,583	33,318	33,318	34,525	16.56%	16.56%	20.79%	15.00%
NPCC-New York	36,230	36,230	42,077	42,077	42,838	16.14%	16.14%	18.24%	16.00%
PJM	163,220	176,420	182,399	182,399	193,691	11.75%	11.75%	18.67%	15.40%
SERC-E	46,386	48,697	56,889	56,889	56,903	22.64%	22.64%	22.67%	15.00%
SERC-N	48,778	52,038	56,402	60,321	64,491	15.63%	23.66%	32.21%	15.00%
SERC-SE	54,249	56,512	65,741	66,041	66,471	21.18%	21.74%	22.53%	15.00%
SERC-W	27,764	28,730	35,450	39,969	44,822	27.68%	43.96%	61.44%	15.00%
SPP	58,985	60,088	67,740	72,823	72,981	14.84%	23.46%	23.73%	13.60%
WECC-BASN	14,756	15,914	15,813	15,813	16,816	7.17%	7.17%	13.96%	12.60%
WECC-CALN	29,077	29,912	31,375	31,375	31,378	7.90%	7.90%	7.91%	14.71%
WECC-CALS	33,319	35,615	38,422	38,422	38,846	15.31%	15.31%	16.59%	15.14%
WECC-DSW	31,013	31,602	40,035	40,035	41,683	29.09%	29.09%	34.40%	13.50%
WECC-NORW	26,711	26,858	31,656	31,656	31,656	18.51%	18.51%	18.51%	17.90%
WECC-ROCK	13,251	13,771	14,313	14,313	14,315	8.02%	8.02%	8.03%	14.65%
TOTAL-UNITED STATES	842,721	888,660	967,375	998,976	1,030,143	14.79%	18.54%	22.24%	15.00%
MRO-Manitoba Hydro	3,474	3,474	4,377	4,377	5,007	25.98%	25.98%	44.11%	12.00%
MRO-SaskPower	3,847	3,938	4,505	4,505	4,505	17.10%	17.10%	17.10%	11.00%
NPCC-Maritimes	3,183	3,514	6,558	6,558	6,558	106.02%	106.02%	106.02%	20.00%
NPCC-Ontario	23,442	23,442	22,791	22,791	28,996	-2.78%	-2.78%	23.69%	20.00%
NPCC-Québec	22,818	22,818	35,306	35,306	35,306	54.73%	54.73%	54.73%	12.20%
WECC-AESO	15,093	15,131	16,375	16,375	16,375	8.50%	8.50%	8.50%	12.24%
WECC-BC	9,670	9,670	11,015	11,015	11,015	13.91%	13.91%	13.91%	12.51%
TOTAL-CANADA	81,528	81,988	100,928	100,928	107,762	23.80%	23.80%	32.18%	10.00%
WECC-MEXW	2,716	2,716	2,924	2,924	3,535	7.65%	7.65%	30.17%	11.86%
TOTAL-MÉXICO	2,716	2,716	2,924	2,924	3,535	7.65%	7.65%	30.17%	11.86%
TOTAL-NERC	**926,965**	**973,364**	**1,071,227**	**1,102,827**	**1,141,441**	**15.56%**	**18.97%**	**23.14%**	**15.00%**

Demand, Resources, and Reserve Margins: 2022/2023 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	61,450	63,336	81,330	81,330	86,794	32.35%	32.35%	41.24%	13.75%
FRCC	48,656	52,408	64,893	68,824	70,529	33.37%	41.45%	44.95%	15.00%
MISO	78,789	83,894	111,704	124,331	125,306	41.78%	57.80%	59.04%	16.30%
MRO-MAPP	5,904	5,904	6,866	6,866	6,866	16.29%	16.29%	16.29%	15.00%
NPCC-New England	20,711	23,686	35,863	35,863	37,070	73.16%	73.16%	78.99%	15.00%
NPCC-New York	25,908	25,908	42,833	42,833	46,110	65.33%	65.33%	77.98%	16.00%
PJM	132,916	146,116	182,401	182,401	193,693	37.23%	37.23%	45.73%	15.40%
SERC-E	46,730	48,395	59,595	59,595	59,609	27.53%	27.53%	27.56%	15.00%
SERC-N	48,256	51,914	70,569	74,560	79,272	46.24%	54.51%	64.28%	15.00%
SERC-SE	50,627	52,894	68,106	68,406	68,751	34.52%	35.12%	35.80%	15.00%
SERC-W	22,262	23,082	44,044	48,312	53,217	97.85%	117.02%	139.05%	15.00%
SPP	44,862	45,726	64,137	68,963	70,538	42.96%	53.72%	57.23%	13.60%
WECC-BASN	12,132	12,437	13,582	13,582	14,571	11.96%	11.96%	20.10%	13.49%
WECC-CALN	20,220	20,498	23,330	23,330	23,502	15.38%	15.38%	16.23%	11.86%
WECC-CALS	25,454	26,607	30,703	30,703	31,117	20.62%	20.62%	22.25%	11.03%
WECC-DSW	20,775	21,065	36,929	36,929	38,169	77.75%	77.75%	83.72%	13.96%
WECC-NORW	32,638	32,759	39,876	39,876	39,878	22.18%	22.18%	22.18%	19.90%
WECC-ROCK	11,283	11,521	13,443	13,443	13,458	19.14%	19.14%	19.27%	15.68%
TOTAL-UNITED STATES	709,572	748,149	990,204	1,020,148	1,058,450	39.55%	43.77%	49.17%	15.00%
MRO-Manitoba Hydro	5,162	5,162	5,552	5,552	6,182	7.54%	7.54%	19.75%	12.00%
MRO-SaskPower	4,310	4,401	4,953	4,953	4,953	14.93%	14.93%	14.93%	11.00%
NPCC-Maritimes	5,285	5,552	6,861	6,861	6,861	29.82%	29.82%	29.82%	20.00%
NPCC-Ontario	21,529	21,529	26,858	26,858	33,380	24.75%	24.75%	55.04%	20.00%
NPCC-Québec	40,575	40,575	45,906	45,906	45,906	13.14%	13.14%	13.14%	12.20%
WECC-AESO	15,994	15,994	18,124	18,124	18,124	13.32%	13.32%	13.32%	11.71%
WECC-BC	12,823	12,823	14,467	14,467	14,467	12.82%	12.82%	12.82%	16.16%
TOTAL-CANADA	105,679	106,037	122,721	122,721	129,873	16.13%	16.13%	22.89%	10.00%
WECC-MEXW	1,841	1,841	2,772	2,772	3,384	50.59%	50.59%	83.81%	10.71%
TOTAL-MÉXICO	1,841	1,841	2,772	2,772	3,384	50.59%	50.59%	83.81%	10.71%
TOTAL-NERC	**817,092**	**856,027**	**1,115,697**	**1,145,641**	**1,191,707**	**36.54%**	**40.21%**	**45.85%**	**15.00%**

ERCOT

Planning Reserve Margins

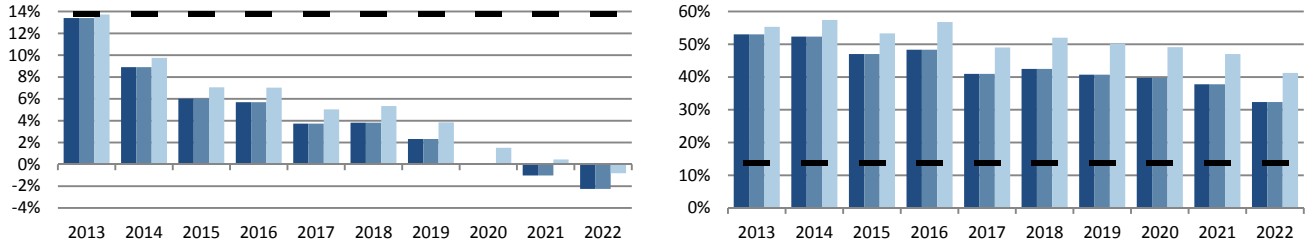
Based on current information regarding Future-Planned generation, the ERCOT Region will not maintain adequate Planning Reserve Margins throughout the assessment period. The Anticipated, Prospective and Adjusted Potential Reserve Margins are expected to be below the NERC Reference Margin Level of 13.75 percent as early as the 2013 summer. The Total Potential Resources Reserve Margin is forecast to drop below the NERC Reference Margin Level in 2014. The Anticipated and Prospective Reserve Margins for 2013 are forecast to be 13.4 percent. Given expected load growth and limited knowledge of future generation development and retirements, Reserve Margins are expected to decline through the end of the assessment period (ERCOT-Table 1 and ERCOT-Figure 1).

ERCOT-Table 1: Planning Reserve Margins

ERCOT-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		13.40%	8.91%	6.02%	5.69%	3.72%	3.82%	2.33%	0.04%	-1.02%	-2.26%
PROSPECTIVE		13.40%	8.91%	6.02%	5.69%	3.72%	3.82%	2.33%	0.04%	-1.02%	-2.26%
ADJUSTED POTENTIAL		13.72%	9.75%	7.06%	7.03%	5.04%	5.34%	3.84%	1.52%	0.44%	-0.82%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

ERCOT-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		53.03%	52.33%	47.01%	48.32%	40.96%	42.49%	40.71%	39.72%	37.78%	32.35%
PROSPECTIVE		53.03%	52.33%	47.01%	48.32%	40.96%	42.49%	40.71%	39.72%	37.78%	32.35%
ADJUSTED POTENTIAL		55.34%	57.43%	53.33%	56.81%	49.02%	52.00%	50.20%	49.10%	47.03%	41.24%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

ERCOT-Figure 1: Summer (Left) and Winter[116] (Right) Planning Reserve Margins



Expectations that reserve margins will be below the minimum NERC Reference Margin Level are a result of limited knowledge of plans for future generation development and retirements, especially due to uncertainty in the generation marketplace. With no administrative requirement for market participants to notify ERCOT of their long-term generation development plans, generation additions and retirements beyond those that are currently being reviewed for interconnection to the transmission system are not known and cannot be included in this assessment. Additionally, the exclusion of hydro generation capacity during the peak further reduces Planning Reserve Margins throughout the assessment period.

Historically, in both internal and external assessments, ERCOT has assumed hydro generation capacity to be unavailable during the peak. Recent ERCOT internal discussions have led ERCOT staff to believe the inclusion of all hydro generation capacity is appropriate. Texas Reliability Entity (TRE) does not currently share this view and is awaiting a technically justifiable approach for inclusion (either total or partial), of the hydro capacity values during the peak. The inclusion or exclusion of ERCOT's 544 MW of hydro generation capacity has important implications for the area's Anticipated Reserve Margins and its proximity to the NERC Reference Margin Level. Accordingly, TRE and ERCOT staff will continue to work together to determine a technically justifiable resolution, which may require changes in ERCOT stakeholder procedures.

[116] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

The Public Utility Commission of Texas (PUCT) is responsible for ensuring that the market design promotes an adequate level of resources required to serve expected loads. There is no requirement for any entity to plan for – or ensure – adequate levels of future resource additions. The ERCOT market design provides an opportunity for any interested stakeholder to develop new generation and bid into the electricity market.

Given adequate time for development of new generation, regulatory or market changes resulting in idling or retirement of generation facilities are not expected to have a significant impact on projected Reserve Margins. However, due to environmental requirements and regulatory changes that result in significant accelerated reductions in overall resource capacity or regulatory constraints that impede the development of new resources, reduced system reliability due to the impact on Reserve Margins is expected. Regulatory uncertainty gives resource owners added reason to retire existing resources without providing sufficient assurance on future market conditions to developers of new resources. This increases the risk of reduced system reliability.

Demand

Total Internal Demand is forecast to grow at a compounded annual rate of 2.32 percent for the 2013–2022 assessment period (ERCOT-Table 2). The reduction in load forecast growth projections compared to a year earlier, results from changes in the long-range economic forecast, which is obtained from Moody's.[117] The Moody's base-case economic forecast was used to provide forecast, non-farm employment values for 2013–2022. A normal weather year was determined based on actual weather data from 1997 to 2011. Reported peak demands represent the coincident demand for ERCOT.

ERCOT-Table 2: Demand Outlook

ERCOT-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	65,649	80,694	15,045	22.9%	2.32%
Load-Modifying Demand Response	1,279	1,813	534	41.7%	3.95%
TOTAL INTERNAL DEMAND	**66,928**	**82,507**	**15,579**	**23.3%**	**2.35%**
ERCOT-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	50,263	61,450	11,187	22.3%	2.26%
Load-Modifying Demand Response	1,471	1,886	415	28.2%	2.80%
TOTAL INTERNAL DEMAND	**51,734**	**63,336**	**11,602**	**22.4%**	**2.27%**

There are no expected changes in the footprint of the ERCOT Interconnection. There have been no significant changes in the forecasting process since the previous LTRA. The extreme hot weather conditions experienced over the entire ERCOT Interconnection during the summer of 2011 impacted the calculation of average weather conditions,[118] resulting in higher expected peak loads in future years. In the near term, this change in average weather conditions will increase forecast peak loads by approximately 1.2 percent.

Demand-Side Management

Load Resources (LRs) providing Responsive Reserve Service (RRS)[119] are projected to provide 886 MW of dispatchable, contractually committed Demand Response during summer peak hours in 2013 and future years (ERCOT-Table 3).[120,121]

[117] http://www.moodys.com/.
[118] http://www.ercot.com/content/meetings/rpg/keydocs/2012/0817/2011_Long-Term_Load_Forecast_Model_Descript.pdf.
[119] Categorized as Load as Capacity Resource Demand Response in this assessment.
[120] http://www.ercot.com/content/mktinfo/dam/kd/ERCOT Percent20Methodologies Percent20for Percent20Determining Percent20Ancillary Percent20ServicePercent 20Requir.zip
[121] The 886 MW represent LR participation in RRS capacity during the peak month of August 2011 across the peak hours (3-6 PM).

ERCOT-Table 3: Demand-Side Management

ERCOT-Summer	Short-Term 2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	393	432	476	927	534	1.12%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	886	886	886	886	0	1.07%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,279	1,318	1,362	1,813	534	2.20%
TOTAL ENERGY EFFICIENCY	240	366	498	1,506	1,266	1.83%
TOTAL DEMAND-SIDE MANAGEMENT	**1,519**	**1,684**	**1,860**	**3,319**	**1,800**	**4.02%**

Emergency Response Service (ERS, formerly known as Emergency Interruptible Load Service or EILS)[122] is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary Firm load and represents contractually committed interruptible load.[123] Based on the results of the latest bid selection process, ERCOT planned to procure approximately 393 MW of ERS load for the 2013 summer peak. For the 10-year outlook, this procurement is expected to increase by 10 percent per year, reaching 927 MW by 2022. Measurement and verification procedures for the LRs and ERS programs are defined in the Performance Monitoring section of the ERCOT Protocols.[124]

In addition to these two Demand Response programs (LRs and ERS), several Transmission Service Providers (TSP) have their own contractual arrangements with loads that can respond to instructions to reduce their energy usage. The recent implementation of the Demand Response Availability System (DADS) will provide ERCOT better understanding regarding the expected magnitude of load MW in the TSP-based Demand Response programs. ERCOT is working to better coordinate activation of these loads included in the TSP Demand Response programs with ERCOT system operations.

Recent legislation requires utilities to provide Energy Efficiency programs sufficient to reduce their incremental peak demand growth by at least 20 percent each year. These programs include Low Income Weatherization, Energy Star (New Homes), Air Conditioning Efficiency Programs, Air Conditioning Installer Training, Retro-Commissioning, Hard-to-Reach, Load Management, Multifamily Water & Space Heating, Texas SCORE/City Smart, Trees for Efficiency, and Third Party. The incremental effect of this level of reduction is included as New Conservation (Energy Efficiency) in this assessment. The impact of current Energy Efficiency is reported to the PUCT on an annual basis. ERCOT does not verify or measure the impact of Energy Efficiency programs.

Utility savings, as measured and verified by an independent contractor, have exceeded the goals set by the utilities.[125] In a recent assessment, utility programs implemented after electric utility industry restructuring in Texas had produced 301 MW of peak demand reduction and 536 GWh of electricity savings for 2010.[126] This demand reduction is accounted for within the load forecast, and only the incremental portion, which is expected to increase from 240 MW in 2013 to 1,506 MW in 2022, is included as a demand adjustment for the summer seasons during the assessment period.

Generation

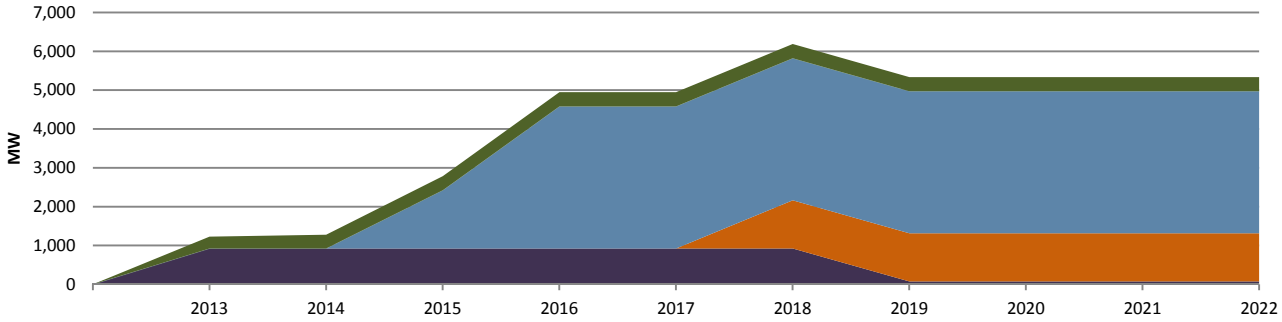
Existing-Certain generation capacity in ERCOT, as currently reported by the generation resource owners, is 73,018 MW (ERCOT-Table 4). The primary fuel sources for generation in ERCOT are natural gas and coal. Since the 2011 summer season, 1,597 MW of generation capacity has been added or will return to service. The generation capacity consists of 1,260 MW of gas generation (which includes 553 MW of mothballed units returned to service), 275 MW of coal generation, 35 MW of wind generation (with nameplate capacity of 402 MW), and 27 MW of solar generation. There are 2,962 MW of "switchable" generation that can operate in the ERCOT system or in the adjacent (not synchronously interconnected) Southwest Power Pool Region. ERCOT counts all of the switchable generation capacity as Existing-Certain capacity, except for 317 MW, which is obligated to serve load outside of ERCOT through the year 2020.

[122] Categorized as Contractually Interruptible (curtailable) Demand Response in this assessment.
[123] See Section 3.14.3 of the current ERCOT protocols:http://www.ercot.com/content/mktrules/nprotocols/current/03-051012_Nodal.doc
[124] http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc
[125] http://www.texasefficiency.com/images/documents/Publications/Reports/EnergyEfficiencyAccomplishments/eummotreport2010.pdf
[126] http://www.puc.state.tx.us/industry/projects/rules/38578/EUMMOT_EEIP_June_2_2011.pdf

ERCOT-Table 4: Capacity Outlook[127]

	Current		2022 Planned			2022 Planned & Conceptual		
ERCOT-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	18,215	24.9%	18,290	23.3%	75	20,580	24.5%	2,365
Petroleum	138	0.2%	1,378	1.8%	1,240	1,378	1.6%	1,240
Gas	48,355	66.2%	52,012	66.4%	3,657	53,756	63.9%	5,401
Nuclear	5,150	7.1%	5,150	6.6%	0	5,150	6.1%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	1,160	1.6%	1,525	1.9%	365	3,230	3.8%	2,070
TOTAL	**73,018**	**100.0%**	**78,355**	**100.0%**	**5,337**	**84,095**	**100.0%**	**11,076**

ERCOT-Figure 2: Summer Net Capacity Change



Before a new power project is included in reserve margin calculations, a binding Interconnection Agreement (IA) must exist between the resource owner and the Transmission Service Provider (TSP). Additionally, thermal units must have an air permit issued from the appropriate state and federal agencies specifying the conditions for operation. Future-Planned Resources expected through the assessment period (2013–2022) include 3,657 MW of gas-fired generation, 75 MW[128] of coal-fired generation, 1,240 MW of petroleum coke-fueled generation, 60 MW of solar generation, 105 MW of biomass generation, and 200 MW of on-peak wind generation (2,098 MW of wind derate on-peak). There is 1,224 MW of on-peak wind generation (11,260 MW of wind derate on-peak) considered as Conceptual capacity for the 2013-2022 assessment period (ERCOT-Table 5, ERCOT-Figure 2, ERCOT-Table 6, ERCOT-Figure 3, ERCOT-Table 6).

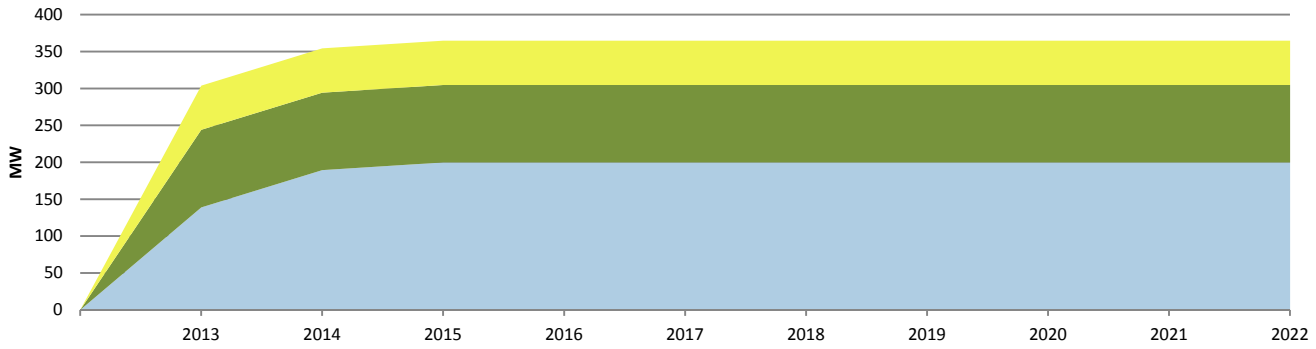
[127] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[128] Future-Planned coal unit retirements nearly offset Future-Planned unit additions, resulting in only 75 MW of added coal capacity by 2022.

ERCOT-Table 5: Renewable Capacity Outlook[129]

	Current		2022 Planned			2022 Planned & Conceptual		
ERCOT-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	0	0.0%	0	0.0%	0	0	0.0%	0
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	873	75.3%	1,073	70.4%	200	2,297	71.1%	1,424
Biomass	213	18.4%	318	20.9%	105	318	9.8%	105
Solar	74	6.4%	134	8.8%	60	615	19.0%	541
TOTAL	**1,160**	**100.0%**	**1,525**	**100.0%**	**365**	**3,230**	**100.0%**	**2,070**

ERCOT-Figure 3: Summer Net Renewable Capacity Change



One 925 MW thermal generation project was expected to become available prior to the 2012 summer season. However, this project has been delayed and is now expected to be available in March 2013. ERCOT has been notified that the Cobisa-Greenville gas-fired plant (1,792 MW), tentatively scheduled to be on-line by 2016, has been indefinitely delayed. In addition, a gas plant that was expected to be on-line prior to the summer of 2014 has been delayed and is now expected in January 2015. ERCOT has not been notified of any other project deferments. However, the status of Future-Planned gas-fired resources is being reviewed frequently; current market conditions caused by low natural gas prices are not conducive to gas generation market investment.

ERCOT Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
ERCOT-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	10,035	74	544	213	12,333	134	544	318
On-Peak Derate	9,162	0	544	0	11,260	0	544	0
EXPECTED ON-PEAK OUTPUT	873	74	0	213	1,073	134	0	318

In order to gain additional insight into any impediments to investment in generation resources in ERCOT, the Region commissioned The Brattle Group to conduct a review of current market conditions and the impact on generation development.[130] The primary report high-level recommendations are for the Public Utility Commission of Texas (PUCT) and ERCOT to: (1) evaluate and define resource adequacy objectives for the BPS; and then (2) choose a policy path to meet those objectives, based on the advantages and disadvantages of each option identified. ERCOT has not been formally notified of any resource retirements, although one resource owner has publicly announced that they will retire the J.T. Deely coal-fired plant (845 MW) by the end of 2018. This expected retirement is included in this assessment.

Given the current market design, in which no party has a requirement to develop or maintain generation resources, ERCOT will study the potential impact of any announced unit retirements and will work with resource owners to finalize reliability-must-run contracts in the event that units are required to maintain system reliability. ERCOT will develop analyses of

[129] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[130] Operations and System Planning document titles "The Brattle Group Report": http://www.ercot.com/news/presentations/index#.

reliability and market impact of potential expected retirements as needed and make this information available to market participants so that developers and investors can accurately assess future market opportunities.

There are no planned unit uprates or non-traditional resources included in the Future-Planned, Future-Other, or Conceptual resources. Several units with a total capacity of 553 MW that had been idled (or mothballed) by the respective owners have returned to service since last summer. As ERCOT has not been notified that these units will return back to mothballed status, the units are considered to be available throughout the assessment period. However, given that the units are older, less efficient, and previously determined not to be cost-effective by the owners, it is unlikely that these units will remain completely available throughout the assessment period. Essentially, the summer season appears to provide an economic viability opportunity for these units to return to service for the summer seasons but return to mothball status during off-peak periods.

Two storage facilities (76 MW of batteries considered as Conceptual resources) are currently being reviewed by ERCOT staff for possible interconnection before 2013. The facilities have publicly announced plans but have not completed the ERCOT process to be included in Planned or Existing-Certain Capacity categories.

ERCOT has a number of resources categorized as behind-the-meter (or Private-Use Network) generation. The capacity from these resources provided to the grid is assessed on a regular basis; operational data from the summer of 2011 indicates that these resources are able to provide 4,390 MW during peak hours. Previously ERCOT had surveyed behind-the-meter generation owners to determine what capacity may be available to the ERCOT grid, but ERCOT staff recently determined that using actual availability provided a more technically acceptable value. ERCOT will work with owners of behind-the-meter generation to ensure that changes in the aggregate capability of these resources are appropriately quantified in future resource assessments.

Of the Existing-Certain generation capacity, 108 MW is biomass and 74 MW is solar. ERCOT counts these resources as available on-peak. There are 544 MW of hydro generation capacity in ERCOT; internally (i.e., within ERCOT internal assessments) this capacity is expected on-peak but for this NERC assessment hydro generation capacity has been derated to zero (0) MW, as has been done historically. Of the 9,829 MW of existing wind generation capacity and 2,298 MW of Future-Planned wind generation capacity, 855 MW of Existing and 200 MW of Future-Planned is included in the expected on-peak resources, respectively. The currently approved Effective Load Carrying Capability (ELCC) of wind resources in ERCOT is 8.7 percent. The ELCC of wind generation is determined as part of the ERCOT Region Target Reserve Margin evaluation using a Loss of Load Probability Monte Carlo model.[131]

ERCOT has significant experience maintaining operational reliability with significant and increasing levels of interconnected variable generation. Using a combination of state-of-the-art wind generation forecasts and flexible levels of ancillary services, ERCOT will effectively manage available wind and solar generation to support system reliability utilizing current procedures. Continuing development of wind resources along the Texas coast, which exhibit generation patterns that are more correlated with summer peak loads than wind sited in inland western portions of Texas, is also expected to increase the overall reliability benefit from wind generation. An evaluation of possible differences in a locational-based wind ELCC is in progress.

With only 74 MW of registered solar resources in ERCOT (not including smaller solar resources that do not participate in the wholesale energy market) and only 60 MW of solar resources included in the Future-Planned Category, the variability of these resources will not adversely affect the reliability of the grid. As future solar generation becomes more prevalent in ERCOT, it will become necessary to develop an estimate of the ELCC of solar resources and to develop a process for forecasting solar resources.

[131] Item 14 documents located at http://www.ercot.com/calendar/2010/11/20101104-TAC give more details.

Less than 1 percent of the ERCOT generation capacity is hydro (544 MW). These facilities are typically operated as run-of-river or planned release due to downstream needs and not operated specifically to produce electricity. However, these resources may be available during peak conditions, either to provide energy or to provide ancillary services, ensuring units are available to provide energy to serve Firm load.

Capacity Transactions

ERCOT is a separate interconnection with only asynchronous ties to the Southwest Power Pool (SPP) and Mexico's Comisión Federal de Electricidad (CFE). ERCOT does not share reserves with other Regions. There are two asynchronous ties between ERCOT and SPP, providing a sum of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico, with a total of 280 MW of transfer capability.

ERCOT does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements, it may request external resources for emergency services over the asynchronous ties or by block transfer of discrete loads. Under peak conditions for the assessment period, ERCOT is expected to have 458 MW of imports from SPP and 123 MW from CFE. Of the imports from SPP, 48 MW is tied to a long-term contract for a purchase of Firm power from specific generation. The remaining imports of 410 MW from SPP and 123 MW from CFE represent one-half of the asynchronous tie transfer capability, included to reflect emergency support arrangements. Total Firm imports amount to 598 MW throughout the 2013–2022 outlook (ERCOT-Table-7).

ERCOT-Table 7: Projected Capacity Transactions

ERCOT-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	598	598	598	598	598	598	598	598	598	598
TOTAL IMPORTS	598	598	598	598	598	598	598	598	598	598
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	317	317	317	317	317	317	317	317	0	0
TOTAL EXPORTS	317	317	317	317	317	317	317	317	0	0
TOTAL NET CAPACITY TRANSACTIONS	**281**	**281**	**281**	**281**	**281**	**281**	**281**	**281**	**598**	**598**

Additional asynchronous tie capacity between ERCOT and other Regions is being developed by independent market participants. The Southern Cross[132] and the Tres Amigas[133] projects could add a combined 3,000–6,000 MW of import and export capacity between ERCOT and other Regions (SERC, WECC and SPP). Both of these projects are in the market subscription stage; if either project garners sufficient market subscriptions to become viable, a target project completion date will be set, additional studies regarding the impact of the project will be conducted, and the additional tie capacity will be included in future assessments.

Several SPP members own 317 MW of a power plant located in ERCOT, resulting in a Firm export of that amount from ERCOT to SPP. This contract is currently expected to terminate before the peak season of 2020. There are no known non-firm contracts signed or pending, or any other contracts that are known to be under negotiation or study (outside of the two projects described in the previous paragraph).

Transmission

There are currently 4,974 circuit miles of 345 kV transmission additions planned in ERCOT during the 2013–2022 assessment period. This total includes the transmission improvements designed to connect five designated Competitive Renewable Energy Zones (CREZ) in west Texas to major load centers in Texas.[134] The CREZ project alone includes more than 2,300 circuit miles of 345 kV transmission right-of-way. Six of the new rights-of-way will include series compensation, mostly located at intermediary substations. The CREZ project will include approximately 1,400 MVars of Static Var Compensators (SVC), 4,000 MVars of shunt reactors, and 1,000 Mvars of shunt capacitors. This project also includes upgrades of several circuits, many immediately west of Fort Worth and northwest of San Antonio, where the CREZ circuits

[132] http://www.southerncrosstransmission.com/project_documents/southern_cross_fact_sheet.pdf
[133] http://www.tresamigasllc.com/index.php
[134] http://www.texascrezprojects.com/default.aspx

connect with existing infrastructure. All of these improvements are scheduled to be completed by the end of 2013. It is expected that these new and upgraded circuits will eliminate the existing West-to-North Dynamic Stability limit, which limits power flows from the West Zone to the North Zone. ERCOT is reviewing the proposed configurations to see if new interface limits may occur during and after the CREZ line construction.

Existing and projected transmission lines for the ERCOT Assessment Area are as follows (ERCOT-Table 8):

ERCOT-Table 8: Existing and Projected Transmission

ERCOT	AC(Circuit Miles)	DC(Circuit Miles)	Total(Circuit Miles)
EXISTING	29,465	0	29,465
Currently Under Construction	946	0	946
Planned - Completed within First Five Years	4,757	0	4,757
Planned - Completed within Second Five Years	29	0	29
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	35,197	0	35,197
Conceptual - Completed within First Five Years	800	0	800
Conceptual - Completed within Second Five Years	391	0	391
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**36,388**	**0**	**36,388**

A new 345 kV transmission line with series compensation is planned to connect the Laredo Area with the Lower Rio Grande Valley Area. The line will support the high load growth projected for the Lower Rio Grande Valley Area, as well as provide longer-term benefits for the Laredo Area. It is projected to be in service by the summer peak of 2016. This project will increase the limit of power flows between the rest of ERCOT and the Lower Rio Grande Valley region.

Current transmission plans during the assessment period include the installation of thirty-four 345/138 kV autotransformers to support load growth and the reliability of the ERCOT Interconnection.

There is a transmission constraint commonly referred to as the North-to-Houston Voltage Stability Limit and considered an Interconnection Reliability Operating Limit (IROL) that is managed daily. At this point, there has been no information regarding the future mitigation of that IROL. ERCOT is reviewing the September 8, 2011 Southwest Blackout Event[135] recommendations to determine whether any procedural changes may be necessary regarding IROL identification, as well as other aspects of the report.[136] ERCOT does not have any additional transmission constraints that are expected to significantly impact reliability.

A major planned circuit connecting the Fayetteville and Zenith substations (west of Houston) has been cancelled. This project was endorsed by ERCOT in 2010 based on aggregate reduction of market prices due to reduced congestion into the Houston Area. This project was not required in order to maintain adequate system reliability. Following project endorsement, the PUCT changed the economic planning criteria for transmission in ERCOT, eliminating the consideration of market prices from the process. This change resulted in the cancellation of the Fayetteville to Zenith project. ERCOT planning studies will continue to review the possible need for additional transmission projects in and around the major load centers, including Houston.

No project delays or long-term outages that are expected to affect system reliability are known at this time. Outage analysis in the Operations Planning and Operations horizons ensure that system outages, transmission or generation, are only taken if they do not compromise system reliability.

ERCOT ensures that adequate transmission is planned and constructed to support new generation and increasing loads through a coordinated planning process, including long-range studies, mid-term transmission planning, and stability analyses over a range of planning horizons and system conditions. The ERCOT Five-Year Transmission Plan study[137] and

[135] http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.
[136] Recommendations in Appendix B starting on page 116 of the report located at http://www.nerc.com/files/AZOutage_Report_01MAY12.pdf
[137] This study is not available to the public. A description of the process used to develop this study is included within the "ERCOT Regional Planning Group – Chapters and Procedures." http://www.ercot.com/content/committees/other/rpg/keydocs/2012/RPG_Charter_and_Procedure_20090716_Approved.pdf.
Charter and Procedures

additional voltage stability studies through the 2015 summer peak network conditions identify limiting elements under contingency. Based on the results of these studies, ERCOT proposes projects as needed to mitigate any system deficiencies.

Reactive margins are analyzed in the planning horizon. In the operating horizon, reactive margins are maintained in the major metropolitan areas through real-time analysis. Areas of dynamic and static reactive power limitations are Corpus Christi, Houston, Dallas/Fort Worth, and Lower Rio Grande Valley. Operating Procedure Manual for the Transmission and Security Operating Procedure 6.1, Voltage Control, describes the procedure to monitor the system and to prevent voltage collapse using an on-line voltage stability analysis tool.[138]

ERCOT plans for a 5 percent voltage stability margin for NERC Category B contingencies and a 2.5 percent margin for NERC Category C contingencies.[139] ERCOT planning criteria are intended to maintain sufficient dynamic reactive capability to maintain system voltages within the range for which generators are expected to remain on-line. Potential problems are reported to ERCOT System Planning and the affected Transmission Planners (TPs) to develop corresponding transmission projects to resolve the lack of voltage stability margin and to Transmission Operators for their reassessment for the operating horizon.

Significant substation equipment installed or planned for the ERCOT Region includes:

- 300 Mvar Static Var Compensator (SVC) at the Tesla 345kV Station (CREZ-related)
- 2 x 300 Mvar SVC at the Brown 345kV Station (CREZ-related)
- 300 Mvar SVC at the Parker 345kV Station (CREZ-related)
- 200 Mvar SVC at Hamilton 138kV Station (CREZ-related)

Vulnerability Assessment

Given recent rainfall, drought conditions in ERCOT are significantly less severe than they were in 2011. There are no immediate concerns regarding the impact of reduced water levels or increased water temperatures on generation resources. However, ERCOT continues to work with resource owners to closely monitor the availability of water resources at generating plants. ERCOT is also working with several national laboratories on an analysis of the potential impact of a multi-year sustained drought on system needs as part of the long-term transmission planning process. The results of this analysis will be included in the internal ERCOT Long-Term System Assessment scheduled to be completed in December 2012.

Unit outages are reviewed and approved or denied in the outage scheduling process. In addition, as part of the analysis of the impact of changing environmental regulations, ERCOT is working directly with resource owners to assess the potential impact of extended outages to install additional emissions control technologies. At this time, there are no known extended outages that are expected to have an impact on system reliability. This is primarily due to regulatory uncertainty and the required analysis that will need to be completed to determine the affected unit economic viability.

The Renewable Portfolio Standard (RPS)[140] for Texas (including areas of Texas that are outside of ERCOT) is 5,880 MW of installed renewable capacity by 2015 and 10,880 MW of installed capacity by 2025. Each entity that serves load is required to obtain sufficient renewable energy credits from renewable resource owners (one credit for each megawatt produced from a renewable resource) to represent their market share of energy sales times the renewable capacity goal. The 2025 target has already been met. These targets may be changed by the state legislature, which convenes at the start of every odd-numbered year.

A wind integration study completed for ERCOT in 2008 indicated that the current nodal operating procedures, with purchases of suitable amounts of ancillary services, would be appropriate for levels of integrated wind generation capacity

[138] http://www.ercot.com/content/mktrules/guides/procedures/Transmission Percent20and Percent20Security Percent20Operating Percent20Procedure Percent20V1Rev16.doc
[139] See Section 4.1.1 of the ERCOT Planning Guides: http://www.ercot.com/content/mktrules/guides/planning/current/04-090111.doc
[140] http://www.puc.state.tx.us/rules/statutes/Pura09.pdf; Section 39.904

up to 15,000 MW. This level is greater than the current RPS targets, even for 2025, and greater than the amount of wind capacity in the Existing-Certain and Future-Planned categories. ERCOT has implemented a wind power forecasting system to allow ERCOT system operators to identify and take appropriate action when wind resource schedules may not track expected changes in wind production. ERCOT has also implemented a wind ramp forecasting tool that provides a probabilistic assessment of the magnitude and likelihood of a significant change in aggregate wind output over upcoming operating periods. In addition, ERCOT evaluates the impact of increased installed wind generation on ancillary services requirements on an ongoing basis.[141]

Levels of solar resources currently in the interconnection queue are unlikely to have an adverse impact on system reliability. ERCOT works with market stakeholders to ensure that procedures and processes are sufficient to reliably integrate variable resources through operating practices. The Emerging Technologies Working Group has been established to track issues[142] and make recommendations regarding the integration of new technologies, particularly variable resources.

There are no anticipated reliability concerns resulting from unresponsive or unavailable Demand Response. There are specific measurement and verification procedures for the coordinated Demand Response programs.[143] Both LRs and ERS products are subject to unannounced load-shed testing, to be followed by an additional test if the first is unsuccessful. A second consecutive unsuccessful test subjects the resource to suspension. In addition, these resources are monitored using after-the-fact metering and are subject to payment reductions and suspension from the program for failing to meet availability requirements.

These Demand Response programs (LRs and ERS) are utilized in the event of a sudden loss of generation (LRs) or in the event of an imminent shortage of system-wide generation (LRs and ERS). Response from these resources has been satisfactory in previous events in which they were utilized.

Similarly, there are no expected reliability concerns related to high levels of Demand Response resources. ERCOT currently limits the Demand Response participation of LRs at 50 percent of the hourly RRS procurement, for which the minimum requirement is 2,800 MW. This participation limit is reviewed on a regular basis. LRs are deployed automatically via Under Frequency Relays in response to frequency excursions below 59.7 Hz or through manual deployment during system emergencies such as Energy Emergency Alerts.

There are no anticipated reliability concerns with distributed resource integration at this time.

ERCOT plans grid enhancements as needed on a continuous basis and does not plan for additional Under-Voltage Load Shedding (UVLS) schemes as a reliability tool. UVLS deployments are intended to provide a "safety net" in case other operating actions are not sufficient to resolve under-voltage problems. UVLS schemes generally are not relied upon to maintain the overall system stability following NERC Category B and C events,[144] and system reinforcements may be made to limit the amount of load shed that may occur under certain NERC Category D events.

ERCOT works with transmission service providers to minimize the use of Special Protection Systems (SPS) and Remedial Action Plans (RAP).[145] When utilized, these measures will improve rather than adversely impact system reliability and possibly reduce system costs. These measures are typically designed to be temporary—utilized only until a system improvement eliminates the need for the SPS or RAP.[146]

[141] http://www.ercot.com/content/mktinfo/dam/kd/ERCOT Percent20Methodologies Percent20for Percent20Determining Percent20Ancillary Percent20Service Percent20Requir.zip

[142] http://www.ercot.com/content/meetings/tac/keydocs/2010/1104/15._ETIP_draft_v10_102210.doc

[143] As defined in the Performance Monitoring section of the ERCOT Protocols. (http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc).

[144] http://www.nerc.com/page.php?cid=2|20.

[145] A RAP is a predetermined operator action to maintain reliability in a defined adverse operating condition. See Section 4.3.1 of the ERCOT Operating Guides for additional information: http://www.ercot.com/content/mktrules/guides/noperating/current/04-121411.doc

[146] A list of current SPSs and RAPs in ERCOT is available on the ERCOT website: https://mis.ercot.com/pps/tibco/mis/Pages/Grid+Information/Long+Term+Planning

ERCOT works with transmission service providers to develop options in the event of large emergencies. As an example, areas where load transfers can be implemented are reviewed on an ad hoc basis, and in some cases additional transmission equipment to allow such block-load transfers has been installed. Additionally, transmission service providers supply ERCOT with a list of NERC Category D contingencies, which are studied annually.

ERCOT is working with transmission service providers and university researchers to evaluate ways to utilize Phasor Measurement Unit (PMU) data. Current initiatives seek to utilize PMU data to validate aspects of planning stability models and to increase real-time operational awareness.

There are currently over 4.4 million advanced meters being used for customer load settlement in the ERCOT Region. Retail electric service providers are beginning to provide time-of-use rates, although at this point most of these offerings are simply two or three different periods in a day. The potential exists for these load resources to grow into an aggregate size that has an impact on market prices and system reliability. ERCOT will continue to coordinate with the PUCT, with transmission service providers, and retail electric service providers to forecast the potential impact associated with the advanced meter data use, and to quantify the participation of market-driven customer Demand Response in real-time operations.

ERCOT has Operating Guides to address relay misoperations and the defined requirements for registered entities to follow in the event of relay misoperations. Registered entities are required to follow TRE's procedure for misoperations as well. In addition, ERCOT has established the System Protection Working Group, made up of ERCOT market participants with knowledge of relay operations, to investigate relay misoperations and disseminate lessons learned.

ERCOT continues to review the potential impact of changing environmental regulations on system reliability. ERCOT is coordinating directly with resource owners to understand their individual compliance strategies and to aggregate these activities to evaluate the system-wide impact. It is unknown at this time if the recently finalized Mercury and Air Toxics Standard (MATS) will result in retirement of existing coal-fired capacity or if existing coal-fired generation capacity will be retrofitted with additional emissions control technologies. Because the Cross-State Air Pollution Rule (CSAPR) was stayed prior to implementation, and the EPA proposed rule revisions that may or may not be implemented depending on the ruling of the D.C. Court of Appeals, it is not known if the CSAPR predecessor, the Clean Air Interstate Rule (CAIR), will have a near-term impact on available resources. However, the combined impact of sustained low natural gas prices, current economic and market conditions, regulatory uncertainty, and other environmental regulations could result in decisions by resource owners to retire units. If these decisions are made in a time frame that does not allow for market investment in new generation resources, overall system reliability will be adversely affected.

Representatives of the Texas Commission on Environmental Quality (TCEQ)[147] have informed ERCOT that the emissions requirements in the MATS rule for Future-Planned and Conceptual solid-fuel units are more stringent than those included in recently finalized air permits for several new plants. This discrepancy could force these new units to reapply for air permits and could result in project delays or cancellations.

A review of the impact of proposed environmental regulations on the ERCOT system completed in June 2011 noted the potential impact of upgrade requirements on old gas-steam generation units.[148] As these units are only utilized during peak load conditions, they do not generate sufficient revenue to warrant even minor capital additions. As a result, any retrofit requirement (such as potential entrainment/impingement limitations resulting from proposed Clean Water Act Section 316 (b) implementation) could lead to significant retirements of gas-steam units. The report cited above noted as much as 9,800 MW of vulnerable generation capacity. Much of this generation is located in or near urban centers; retirement of these units would result in a need for new generation and, potentially, new generation and transmission to increase import

[147] http://www.tceq.state.tx.us/.
[148] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf

capability into these affected load centers. Redevelopment of existing brownfield generation facilities could reduce the need for new transmission, but such redevelopment could be hindered by limited existing gas pipeline infrastructure and by air quality permitting requirements.

ERCOT recently commissioned Black and Veatch to conduct a review of the potential impact of gas curtailment on the ERCOT grid.[149] The study indicates a significant amount of redundancy and robustness in gas supply to generation facilities. While the greatest risk to generation loss was found to be the result of freezing weather, even in extreme weather the regional pipeline capacity was found to be adequate to meet current generation demands.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

Each individual generator owner/operator has to evaluate the environmental regulations to determine their applicability and the risk and impact to specific sites. If there is an impact noted a financial evaluation of the various options available to the owner/operator (e.g. wet limestone scrubber, dry sorbent injection, selective non-catalytic reduction, closed-loop cooling tower, baghouse, etc) would occur. Additional in-depth review of near- and long-term markets and the companies individual strategies associated with those markets would need to occur to evaluate economic viability. At this point, no resources owners have informed ERCOT of the need to retrofit or retire existing generation in order to comply with recently finalized environmental regulations. ERCOT performed two assessments of the potential impacts of environmental regulations on resources. Reports describing the methodologies and results of these studies are available on the ERCOT web site[150,151]. The reports assess the potential impacts of environmental regulatory changes based on ERCOT reviews of published nation-wide impact studies of the proposed regulations. In addition, ERCOT met with environmental experts from several of the generating entities in the ERCOT Region. Using information obtained from these reviews, ERCOT developed scenarios based on likely compliance requirements and future market conditions and evaluated the economic value of affected generating units. It should be noted that there is a great degree of uncertainty in the environmental regulation implementation horizon that hinders efforts to develop firm plans for resource owners and ERCOT.

ERCOT has not recently formally received nor requested any updated specific plans from generator owner/operators to achieve compliance with the environmental standards. Some owners have informally noted that compliance will be achieved through low capital cost plant changes and fuel switching. As noted in an ERCOT assessment[152], the compliance requirements of the regulations and the compliance schedules will have a significant impact on system reliability.

ERCOT has not recently received nor requested any specific plans to achieve compliance with the environmental standards. There is a general concern by Texas RE that lack of sufficient planning, largely due to uncertainty regarding the environmental regulations, by and between the generator owners/operators and ERCOT, may result in a significant demand on internal and external personnel resources and, possibly, equipment necessary to provide compliance.

The installation of environmental controls or other facility enhancements may require an extended outage for each associated generating unit. If the compliance schedule to implement the solutions is overly restrictive, a significant number of units may request to be unavailable at the same time, possibly resulting in ERCOT not being able to approve all the outages necessary and still maintain system reliability. As was shown in December 2011, when Luminant announced the idling of coal-fired Monticello Units 1 and 2[153] due to CSAPR, ERCOT study methodologies indicated that the units were not required for transmission reliability but could cause ERCOT to drop below its Target Reserve Margin. ERCOT decisions avoided subjecting Luminant to possible litigation as a result of probable EPA regulation violations by not finding the Luminant units necessary to maintain reliability of the ERCOT Interconnection. The finding followed the current local rules associated with determining "reliability must run" unit designation and there have been limited changes to those rules

[149] http://www.ercot.com/content/news/presentations/2012/BV Percent20ERCOT Percent20Gas Percent20Study Percent20Report Percent20March Percent202012.pdf
[150] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf
[151] http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf
[152] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf
[153] http://www.luminant.com/news/spotlight/detail.aspx?FtID=23

since December 2011. However, ERCOT rules were changed to allow ERCOT to recall "mothballed" units for imminent emergencies. In August 2012 Luminant provided a suspension of operations notice to ERCOT indicating that the Monticello Units 1 and 2 would be offline starting December 2012 for a minimum of six (6) months and no more than seven (7) months due to low energy prices within the ERCOT market not environmental regulations. ERCOT subsequently removed the units from the preliminary Seasonal Assessment of Resource Adequacy for the ERCOT 2012/2013 winter[154].The spring and early summer of 2013 will help ERCOT evaluate impact on the system of an unexpected extended outage above and beyond what normally may occur.

Since there have been no retirement announcements transmission needs have not been identified at this time. However, even at system reserve margin levels at or near the current Target Reserve Margin for ERCOT of 13.75 percent, it is possible that unit retirements could result in significant local congestion. Generation within urban load centers can be operated during peak load periods to limit the amount of power provided by distant generation. The retirement of intra-urban generation resources would result in the need to import more power to serve load, leading to potential overloads and increased reactive power requirements. Given the locations of the potential generation retirements caused by the pending regulations, the two areas of specific concern for transmission reliability are the Dallas/Fort Worth region and the Houston region. A detailed study would be required in order to determine the most cost-effective improvements to maintain transmission system reliability in the ERCOT Region following a significant retirement of generation capacity.

At this point, with limited information available, it is not known whether any possible projects will be completed by 2016. An evaluation of each unit retirement will need completion to determine if a project is needed and what project timeframe will be required. One Transmission Operator in the ERCOT Region, ONCOR, has recently adjusted its planning criteria to accommodate the possibility of no generation being available at an entire site regardless of the reason (market or environmental reasons)[155]. Although not specifically related to the pending environmental regulations, the ONCOR idea addresses the impact of generation loss in an area that results in transmission upgrades and is viewed as a positive proactive planning step in the right direction to address possible issues with environmental regulation impacts. The ONCOR plan to mitigate the congestion condition extends to 2018.

The Public Utility Commission of Texas is currently reviewing additional options to incentivize generation to be built within the ERCOT Region.[156,157] There have been some recent rules changes but more efforts are ongoing to reach the full potential of options.

No announcements have been made by resource owners in the ERCOT region regarding plant retrofits or retirements of resources due to recently finalized environmental regulations.

As noted above, ERCOT has completed two assessments of the potential system impacts due to environmental regulations. Texas RE affirms that ERCOT needs to coordinate more aspects of the environmental impacts, such as outage coordination, internal and external personnel constraints, and, possibly, equipment availability constraints with resource owners to fully understand the developing compliance strategies, and to assess impacts of these compliance actions on grid operations and resource adequacy. Texas RE will monitor ERCOTs progress as the regulatory uncertainty is further clarified and refined.

Standing and Emerging Reliability Issues

Environmental Regulations

The impact of environmental regulations on the ERCOT system was delayed due to the court stay of the Cross-State Air Pollution Rule (CSAPR). Without that stay, the regulations likely would have affected system reliability in 2012. At this point

[154] http://www.ercot.com/content/news/presentations/2012/SARA-Winter2012-13_Preliminary.pdf
[155] http://www.ercot.com/content/meetings/rpg/keydocs/2012/0817/OncorERCOTRPGOdessaNPresentation08172012.pdf
[156] http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf
[157] http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgControl.asp?TXT_UTILITY_TYPE=A&TXT_CNTRL_NO=40000&TXT_ITEM_MATCH=1&TXT_ITEM_NO=&TXT_N_UTILITY=&TXT_N_FILE_PARTY=&TXT_DOC_TYPE=ALL&TXT_D_FROM=&TXT_D_TO=&TXT_NEW=true

the CSAPR predecessor, CAIR, impacts have not been fully evaluated. The Mercury and Air Toxics Standard (MATS) required compliance by 2015 (or within two years of that date with possible compliance extensions). Other regulations (Clean Water Act (Section 316(b)), Coal Combustion Residuals Disposal (CCRD)) may take effect later in this decade.

The impact of proposed environmental regulation on resource adequacy is a standing reliability issue of national interest that has been studied by NERC, ERCOT, and other concerned stakeholders. The EPA has proposed new regulations that, if implemented, may degrade the economic viability of certain generation resources. Specifically, the Clean Water Act (Section 316(b)), the MATS, , and the Coal Combustion Residuals Disposal, as well as the existing CAIR regulations may require retrofits or upgrades or otherwise increase production costs to a point at which retirement of those units may be more plausible than continued operation.

During the 10-year horizon, Generator Owners whose cost of compliance is greater than or equal to the present value of the future predicted stream of revenue associated with a certain generator may opt to retire that unit. Preliminary ERCOT studies for the impact of EPA regulation, not including CSAPR, suggest that 9,800 MW of legacy gas units are at highest risk of accelerated retirement. The combined impact of sustained low natural gas prices, the CAIR, MATS rule, and other regulatory uncertainty may result in the retirement of solid-fuel units as well.

Accelerated generation retirements without accelerated development of new generation resources will further decrease the Reserve Margin within ERCOT. The Reserve Margin in ERCOT is forecast to fall below the required 13.75 percent level in 2013 even without these accelerated retirements.

Preliminary ERCOT studies, which were performed prior to the issuance and subsequent vacating of the CSAPR and assumed implementation of the Clean Air Transport Rule, suggest that coal plants within the Region should continue to be economically viable to operate, unless low natural gas prices and increased carbon emissions fees occur with the pending regulations. Low natural gas prices are present now due to increased production or possible production of shale plays within the continental United States. Gas plants in the ERCOT Region, facing the imposition of closed-loop cooling tower requirements as a part of Section 316(b) of the Clean Water Act, are likely to see less-than-favorable economics for continued operation. ERCOT studies suggest that over 9,800 MW of gas-fired generation near or around the Dallas and Houston Areas may be affected by EPA regulations including Section 316(b) of the Clean Water Act. In addition, ERCOT completed an assessment of the proposed inclusion of Texas in the CSAPR. The assessment found that, if the rule were implemented as scheduled on January 1, 2012, the generators' compliance plans indicated that 1,200 to 1,400 MW of generation would be unavailable year round and an additional 1,800 to 4,800 MW would be unavailable during the off-peak months. If potential retirements occur as projected in various ERCOT studies, reactive support and/or new import paths will be required in the Dallas/Fort Worth and Houston metropolitan areas.

As potential retirements occur as forecast in ERCOT studies, and market conditions do not attract incremental or replacement generation, then Reserve Margins within the ERCOT Region will not be satisfactory during the 10-year horizon. The PUCT has held a number of workshops and regulatory discussions regarding resource adequacy. Redevelopment of existing generation sites would be likely to minimize the need for additional transmission investment. However, many legacy gas plants are located within EPA air quality non-attainment zones. In addition, pipeline requirements of new generation may exceed the capability of pipeline infrastructure at legacy gas plant locations.

If potential retirements occur as forecast in ERCOT studies and incremental or replacement generation is not constructed, then ERCOT will face lower Reserve Margins, decreased ramping capability, and increased transmission congestion. The unavailability of generation due to MATS would increase capacity insufficiency and the need for emergency actions, including rotating outages, not only during the peak months but also during the off-peak months until retrofits or alternative resources are implemented.

It is not clear when resource owners will finalize their compliance strategies due to the uncertainties in the implementation of environmental regulations and the need to verify the effectiveness of available environmental control technologies to

the final approved regulations; until these compliance strategies are evaluated in aggregate, the impact to system reliability cannot be fully quantified. If additional time is required for resource owners to complete their strategies to comply with the MATS rule, they will need to inform the EPA and ERCOT well in advance of the regulatory deadline in order to qualify for the 4th- or 5th-year extensions. It is unknown how changing market dynamics will affect compliance strategies.

The proposed EPA regulations (Clean Water Act Section 316 (b), MATS, and CCRD) have the potential to expedite retirement of legacy generation units and exacerbate resource adequacy issues in ERCOT over the next 10 years.

These regulations may reduce the economic viability of coal facilities with higher emissions rates and over 9,800 MW of legacy gas generation. From a transmission perspective, these potential generation retirements would require new import paths and significant reactive support in the Dallas/Fort Worth and Houston metropolitan areas. From an operational perspective, accelerated retirements, as modeled, would further impact the Planning Reserve Margin shortfall in the ERCOT Region over the assessment period (currently projected to fall below the required 13.75 percent in 2013 without any additional retirements).

Operating Variable Resources

Following the designation of Competitive Renewable Energy Zones (CREZ) and completion of the transmission improvements to serve these areas, the trend of rapid development of renewable energy resources within ERCOT is likely to continue over the next 10 years. Operating the system with increasing amounts of renewable energy presents reliability challenges in longer-term horizons.

Reliable system operation with increasing amounts of renewable energy is a standing issue. This issue has become a core issue in ERCOT. The Emerging Technologies Working Group has developed a process that tracks issues and their solutions associated with renewable integration on an ongoing basis.[158] This issue was also addressed in a study performed by General Electric: ERCOT Wind Impact/Integration Analysis.[159]

The resource mix in the LTRA will change with increasing amounts of renewable energy resources. These variable resources present a range of issues that can affect reliability, including changes to load-serving requirements for dispatchable generation (net load patterns may be different from historical load patterns); the impact on system forecasting capabilities; and system stability impact. Variable generation can be highly locational, often resulting in the need to move power a significant distance from generator to load.

Within the 10-year horizon, ERCOT may have to modify its ancillary services procurement practices and its reliability unit commitment procedures. New ancillary services may need to be developed. Generation resources that may not be needed for a significant amount of energy across the year may need reliability-must-run arrangements to support system reliability. However, these process changes will not be required to integrate renewable resources. Based on the study completed in 2008, at least 3,000 MW of additional wind generation beyond Existing Certain and Future-Planned projections would be required in order for these changes to be necessary or cost-effective.

Increasing amounts of renewable energy may require additional regulating capacity including, but not limited to, increased system ramping capability, additional resources, or both to maintain system frequency in real time.

Studies are required to determine if additional thermal resources will need to be committed, or if alternative transmission improvements are necessary to ensure reliable integration of increasing amounts of renewable energy resources. The studies will be completed by ERCOT staff and ERCOT stakeholders as more renewable resources are projected to be added to the system.

[158] http://www.ercot.com/gridinfo/etts/.
[159] http://www.ercot.com/content/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip.

Currently, localized congestion and Special Protection Systems within generation "pockets" of renewable energy can cause the curtailment of otherwise economic renewable energy. The CREZ process resulted in plans for a 345 kV transmission infrastructure to support the delivery of over 18,000 MW of energy. These transmission circuits are scheduled to be completed by the end of 2013.

Variable generation is typically highly locational. Specifically designed transmission improvements are usually required to move renewable energy from resources to load. The CREZ transmission plan includes over 2,300 new miles of 345 kV right-of-way, 1,400 Mvars of SVCs, 4,000 Mvars of shunt reactors, and approximately 1,000 Mvars of shunt capacitors. This transmission infrastructure is designed to support the delivery of over 18,000 MW of renewable wind energy.

Real-time energy balance and frequency maintenance with an increasing proportion of wind energy and other intermittent resources on the ERCOT system will require updated or revised ancillary service requirements. The GE study indicates that current operations processes and practices are adequate for wind levels up to approximately 15,000 MW. The report conclusions state that beyond that amount, a thorough review of operations practices will likely be required to minimize system costs while maintaining adequate system reliability. The impact of increased solar integration has not been assessed.

The diversity benefits from integration of wind resources in the Texas Panhandle (the northernmost CREZ) are unknown. It is unknown if solar resources will be more prevalent in the urban centers, near the load, or in extreme western and southwestern Texas, where solar insolation can be as much as 30 percent greater.

The ERCOT Region, with almost 10,000 MW of wind generation installed and an additional 2,000 MW currently planned (based on current interconnection agreements) over the next 10 years, must continue to refine its planning and operational procedures to ensure reliable integration of renewable resources. The CREZ, currently under construction, was designed to have adequate transmission capacity for 18,000 MW of renewable energy. As CREZ reaches its designed capacity for renewable resources, ERCOT will continue to monitor the adequacy of its balancing and ancillary service procurement process under increasing proportions of renewable energy to load. ERCOT currently has less than 100 MW of large-scale solar generation. Further study of the expected impact of solar development is required.

FRCC

Planning Reserve Margins

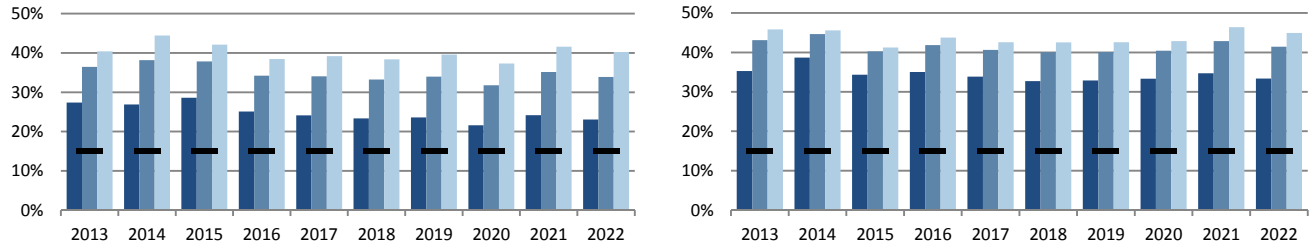
FRCC is projecting adequate Planning Reserve Margins throughout the assessment period (2013–2022). The NERC Reference Margin Level of 15 percent (FRCC-Table 1 and FRCC-Figure 1)[160] was established by FRCC for the entire Region for the entire assessment period. Based on the expected load and generation capacity, the calculated reserve margin is above the NERC Reference Margin Level percent for all summer seasons when demand response (load management and interruptible loads) are treated as load-modifying.

FRCC-Table 1: Planning Reserve Margins

FRCC-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		27.37%	26.88%	28.62%	25.08%	24.12%	23.33%	23.60%	21.58%	24.17%	23.06%
PROSPECTIVE		36.46%	38.18%	37.85%	34.21%	34.06%	33.24%	33.95%	31.76%	35.16%	33.90%
ADJUSTED POTENTIAL		40.42%	44.44%	42.13%	38.46%	39.20%	38.36%	39.60%	37.32%	41.59%	40.25%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

FRCC-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		35.26%	38.69%	34.33%	35.04%	33.85%	32.73%	32.89%	33.31%	34.72%	33.37%
PROSPECTIVE		43.13%	44.67%	40.28%	41.86%	40.64%	40.04%	40.11%	40.44%	42.88%	41.45%
ADJUSTED POTENTIAL		45.83%	45.61%	41.26%	43.77%	42.57%	42.54%	42.58%	42.88%	46.42%	44.95%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

ERCOT-Figure 1: Summer (Left) and Winter[161] (Right) Planning Reserve Margins



A rebound in the economy could potentially increase the demand, energy, and load projections that would realign them with previously reported projections. There is also potential for the passage of pending environmental or regulatory regulations that lead to timing challenges in the retrofitting or building of replacement generation. Unit retirements caused by challenges in complying with environmental rules or other reasons, could result in unscheduled generation outages and corresponding reductions in Planning Reserve Margins.

Demand

The 10-year demand forecast for FRCC is projected to have a CAGR of 1.43 percent (FRCC-Table 2). This outlook is similar to the 2011 forecast, with projected population growth essentially negated by ongoing impacts from the recent economic recession and increased federal and state Energy Efficiency standards.

[160] The FRCC target is 20 percent for Investor-Owned Utilities.

[161] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

FRCC-Table 2: Demand Outlook

FRCC-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	43,041	48,923	5,882	13.7%	1.43%
Load-Modifying Demand Response	3,229	3,660	431	13.3%	1.40%
TOTAL INTERNAL DEMAND	**46,270**	**52,583**	**6,313**	**13.6%**	**1.43%**

FRCC-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	43,049	48,656	5,607	13.0%	1.37%
Load-Modifying Demand Response	3,318	3,752	434	13.1%	1.38%
TOTAL INTERNAL DEMAND	**46,367**	**52,408**	**6,041**	**13.0%**	**1.37%**

Overall projections of load growth for most entities remain at levels below earlier forecasts. The *2012 Annual Energy Outlook* from the U.S. Department of Energy's Energy Information Agency (EIA) indicated that recovery from the recent recession will exhibit the weakest growth of any since 1960.[162] As such, near-term increases in demand are not expected to realign with the more robust projections that were anticipated in projections made prior to the 2008 economic recession.

Load growth across individual Load Serving Entities (LSEs) in the Region is proportional with the level of load growth seen across the FRCC Assessment Area.

Demand-Side Management

The 2013 summer Net Internal Demand (NID) forecast includes the effects of 3,229 MW of potential demand reductions from the use of load management (2,616 MW) and interruptible demand (613 MW).

The 2022 summer NID forecast includes the effects of 3,660 MW of potential demand reductions from the use of load management (3,028 MW) and interruptible demand (632 MW). Load management is projected to increase at a steady rate of 50 MW per year over the forecast horizon, while interruptible demand is projected to essentially remain constant (FRCC-Table 3).

FRCC-Table 3: Demand-Side Management[163]

	Short-Term					
FRCC-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	2,616	2,669	2,720	3,028	412	5.76%
Contractually Interruptible (Curtailable)	613	570	579	632	19	1.20%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	3,229	3,239	3,299	3,660	431	6.96%
TOTAL ENERGY EFFICIENCY	303	461	617	1,443	1,140	2.74%
TOTAL DEMAND-SIDE MANAGEMENT	**3,532**	**3,700**	**3,916**	**5,103**	**1,571**	**9.70%**

All Load Serving Entities (LSE) within FRCC treat Demand Response as load-modifying and not as a capacity resource. Demand reduction is used primarily to shave the peak demand.

There is currently no Renewable Portfolio Standard (RPS) in Florida. A draft rule was submitted by the Florida Public Service Commission staff to the Florida Legislature for consideration;[164] however, the Florida Legislature has not established Renewable Portfolio Standards in Florida.

There are a variety of Energy Efficiency programs implemented by entities throughout FRCC. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high-efficiency appliances (air conditioning, water heater, heat pumps, refrigeration, etc.) rebates and high-efficiency lighting rebates. Total Energy Efficiency programs in FRCC are incorporated into the load forecast, increasing from 303 MW to 1,143 MW over the 10-year period.

[162] The U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2012* (*AEO2012*): http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.
[163] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[164] http://www.psc.state.fl.us/utilities/electricgas/RenewableEnergy/2009_FPSC_Draft_RPS_Rule.pdf.

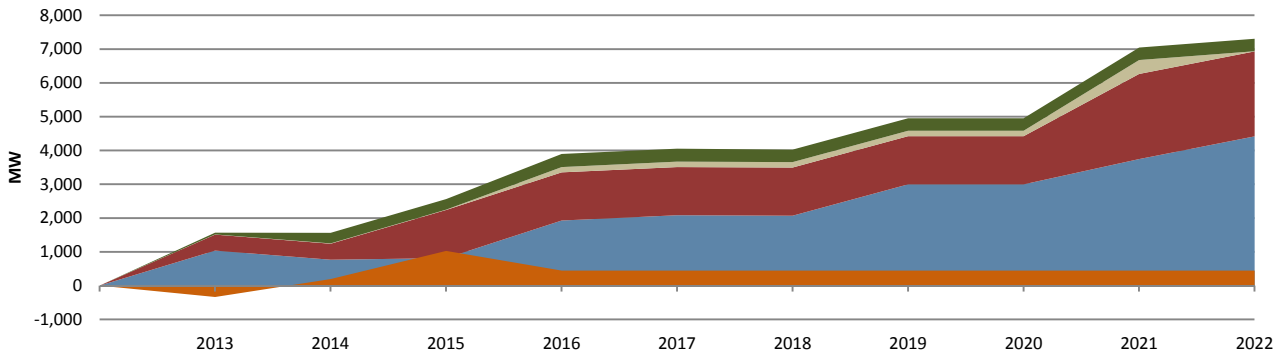
Generation

FRCC supply-side resources considered for the summer assessment are categorized as Existing-Certain, Existing-Other, and Existing-Inoperable. FRCC counts on 51,170 MW of Existing-Certain resources, of which 44 MW are hydro and 374 MW are Biomass. Current solar capacity is projected at 8 MW; however, most of this capacity is derated with approximately 5.8 MW considered as a Firm resource available during peak demand and the remainder being utilized as an energy-only resource. Derated hydro capacity is 44 MW. Approximately 183 MW of Existing-Other merchant plant capability is potentially available as future resources of FRCC members and others, with another 2,019 MW of Existing-Other resources placed into Inactive Reserves or Operational Standby for future operations by FRCC members. Of Existing-Certain capacity, generation fueled by natural gas is the primary source of fuel, supplying nearly 60 percent of capacity, while coal and oil will each account for nearly 16.2 percent. Nuclear generation will contribute about 4.8 percent (FRCC-Table 4, FRCC-Figure 2).

FRCC-Table 4: Capacity Outlook[165]

	Current		2022 Planned			2022 Planned & Conceptual		
FRCC-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	8,430	16.2%	8,428	14.1%	-2	8,428	14.1%	-2
Petroleum	8,458	16.2%	8,906	14.9%	448	8,906	14.9%	448
Gas	32,325	62.0%	36,741	61.3%	4,416	36,741	61.3%	4,416
Nuclear	2,529	4.8%	5,046	8.4%	2,517	5,046	8.4%	2,517
Other/Unknown	3	0.0%	8	0.0%	5	8	0.0%	5
Renewables	426	0.8%	796	1.3%	371	796	1.3%	371
TOTAL	**52,170**	**100.0%**	**59,925**	**100.0%**	**7,754**	**59,925**	**100.0%**	**7,754**

FRCC-Figure 2: Summer Net Capacity Change



The majority of growth in Future-Planned resources is projected to come from plants fueled either by natural gas or nuclear. The construction of new natural gas facilities from 2013-2022 is projected to add over 7,754 MW over the coming decade. Similarly, increases in nuclear capacity over the same time period will come mostly from the uprate of existing units; however, approximately 2,517 MW of new nuclear capacity is scheduled for operation by 2022.

No significant unit retirements, deferments, or derates have been scheduled over the long-term planning horizon. However, there is approximately 850 MW of capacity not included in the forecast due to an extended unit outage. This capacity outage has been replaced with power contracts to meet any obligation-to-serve requirements, as mandated by the Florida Public Service Commission. The capacity outages discussed here is scheduled to return to service in 2014 with no reliability impacts.

There are several plants in FRCC that are either undergoing capacity uprates or have plans to for them in the near-term. Most of these uprates involve modernization of plant equipment. The potential impacts resulting from the temporary unavailability of generation has been mitigated by the short-term activation of off-line capacity that was staged in inactive reserves. Ongoing and future coordination will help to maintain adequate Planning Reserve Margins.

[165] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

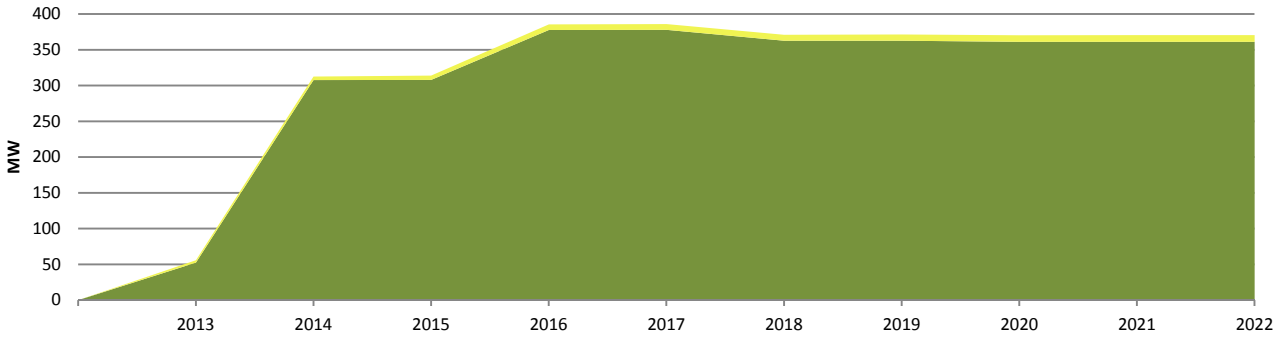
Variable Generation Outlook

Firm capacity from biomass currently supplies about 374 MW during seasonal peak demands, while variable resources such as hydro and solar will contribute about 44 MW and 8 MW, respectively. Approximately 11 MW of hydro is derated and not available during system peak, while the derated capacity from solar amounts to 48 MW (FRCC-Table 5 and FRCC-Figure 2). Even though such derated capacity cannot be used in the calculation of reserve margins, this non-Firm portion of capacity can be utilized as an energy-only resource.

FRCC-Table 5: Renewable Capacity Outlook[166]

	Current		2022 Planned			2022 Planned & Conceptual		
FRCC-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	44	10.2%	44	5.5%	0	44	5.5%	0
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	0	0.0%	0	0.0%	0	0	0.0%	0
Biomass	374	88.0%	736	92.4%	361	736	92.4%	361
Solar	8	1.8%	17	2.2%	9	17	2.2%	9
TOTAL	**426**	**100.0%**	**796**	**100.0%**	**371**	**796**	**100.0%**	**371**

FRCC-Figure 2: Summer Net Renewable Capacity Change



Only the minimum firm capacity from intermittent or energy-limited resources is included in the calculation of seasonal reserve margins. Accordingly, the inherent uncertainty caused by this variability is applied such that the potential unavailability of these resources will not impact reliability (FRCC-Table 6). Currently, no further operational changes are needed or planned to accommodate the integration of variable resources during the long-term planning horizon.

FRCC-Table 6: Variable Generation Outlook

	Current				2022 Planned			
FRCC-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	0	55	55	374	0	82	55	736
On-Peak Derate	0	47	11	0	0	65	11	0
EXPECTED ON-PEAK OUTPUT	0	8	44	374	0	17	44	736

Capacity Transactions

There are 1,340 MW of generation under Firm contract available to be imported from SERC-SE Assessment Area through the end of 2014, with the Firm imports decreasing to 200 MW in subsequent years. Additional capacity transactions include approximately 870 MW from member-owned generation that will be dynamically dispatched from the SERC-SE Assessment Area. These purchases have Firm transmission service to ensure deliverability to FRCC. Total expected Firm imports amount to 2,206 MW until 2016 and drop to 866 MW before increasing to 1,066 MW through the final years of the assessment period (FRCC-Table 7).

[166] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

FRCC has 143 MW of generation under Firm contract to be exported only during the summer season into the SERC-SE Assessment Area throughout 2020. These sales have Firm transmission service to ensure deliverability into the SERC-SE Assessment Area.

FRCC-Table 7: Projected Capacity Transactions

FRCC-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	2,206	2,206	2,206	866	966	1,066	1,066	1,066	1,066	1,066
TOTAL IMPORTS	2,206	2,206	2,206	866	966	1,066	1,066	1,066	1,066	1,066
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	143	143	143	143	143	143	143	143	143	143
TOTAL EXPORTS	143	143	143	143	143	143	143	143	143	143
TOTAL NET CAPACITY TRANSACTIONS	**2,063**	**2,063**	**2,063**	**723**	**823**	**923**	**923**	**923**	**923**	**923**

Neither non-Firm resources nor expected transactions are included in the assessment for the calculation of reserve margins.

FRCC does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts in place between SERC members and FRCC entities.

Transmission

Transmission constraints in central Florida may require remedial actions, depending on system conditions creating increased west-to-east flow across the central Florida metropolitan load areas until the permanent solutions are constructed. No interconnection-related issues have been identified or are anticipated through the assessment period within FRCC. The FRCC planning process identified the following four transmission projects in central Florida as necessary for providing enhanced reliability during the assessment period:

- Intercession City to Gifford 230 kV (new 12-mile line)
- Holopaw to Poinsett 230 kV transmission line (rebuild)
- Tenoroc to Interstate to FiberTek to West 230 kV transmission line (reconductor)
- McIntosh to Lake Agnes 230 kV transmission line (rebuild)

There are no foreseen project delays in meeting the in-service date of any planned transmission facilities that have an impact on the long-term reliability during this assessment period. Any temporary service outages required for construction will be performed during off-peak seasonal conditions and studied in the operations horizon. No significant substation equipment (i.e., SVC, FACTS controllers, HVdc, etc.) additions are expected through 2022.

A list of existing and projected transmission additions is provided below (FRCC-Table 8):

FRCC-Table 8: Existing and Projected Transmission

FRCC	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	12,031	0	12,031
Under Construction	46	0	46
Planned - Completed within First Five Years	249	0	249
Planned - Completed within Second Five Years	200	0	200
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	12,526	0	12,526
Conceptual - Completed within First Five Years	0	0	0
Conceptual - Completed within Second Five Years	97	0	97
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**12,623**	**0**	**12,623**

All Future-Planned generation within the FRCC Region is thoroughly studied by the interconnecting Transmission Service Provider (TSP). The TSP will then submit the results of their study to FRCC's Transmission Working Group (TWG) for additional third-party screening in accordance with the applicable TPL series of NERC Reliability Standards. This additional screening assures that all Future-Planned generation is deliverable (if requested), reliable, and does not adversely impact the BPS within FRCC.

The *FRCC Long Range Study 2012-2021*[167] did not identify any reactive power-limited areas that would impact the BPS through 2021. FRCC has not identified the need to develop specific criteria to establish a voltage stability margin.

The FRCC expects the BPS to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of both the summer and winter peak demand. The results of the annual Long-Range Study, which evaluated the steady-state summer, winter peak and select off-peak load conditions under different operating scenarios, indicates that any concerns with thermal overloads or voltage conditions can be managed successfully by operator intervention or by planned system expansion to serve the forecast demand. The scenarios analyzed included the unavailability of major generating units within the FRCC. Therefore, various dispatch scenarios were evaluated to ensure generating resources within the FRCC are deliverable by meeting NERC Reliability Standards under these dispatch scenarios. No localized pockets of reactive power-limited areas were identified on the BPS within FRCC in the current long-range study.

Vulnerability Assessment

One 800 MW class unit is scheduled to be unavailable during a defined period within the study horizon. Based on the FRCC Long-Range Study, the unavailability of this unit is not anticipated to cause any reliability concerns. In addition, FRCC does not foresee any issues associated with long-term/extended drought conditions, the unavailability of demand resources, or an increase in variable or distributed generation.

There are currently no plans for additional Under-Voltage Load Shed (UVLS) within FRCC. There is currently about 940 MW of UVLS armed within FRCC. These UVLS relays are designed to respond to local low-voltage conditions that could be caused by a Category C or D multiple contingency events. Two new permanent Special Protection Systems were installed within FRCC. The Special Protection Systems are designed to protect BES facilities under certain generation dispatch scenarios and specific multiple contingency events.

Based on past operating experience with the impact of hurricanes on the fuel supply infrastructure within the Region, the FRCC developed a *Generating Capacity Shortage Plan*.[168] This plan can distinguish between generating capacity shortages caused by abnormally high system loads and unavailable generating facilities from those caused by short-term, generating fuel or availability constraints. Since a significant portion of electric generation within Florida uses remotely supplied natural gas, the plan specifically distinguishes generating capacity shortages by primary causes (e.g., hurricanes and abnormally high loads) in order to provide a more effective regional coordination. The FRCC Operating Committee (OC) has also developed *FRCC Communications Protocols – Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers* to enhance the existing coordination between the FRCC Reliability Coordinator and the natural gas pipeline operators in response to FERC Order 698. In addition, the FRCC Operating Reliability Subcommittee (ORS), through its Fuel Reliability Working Group, periodically reviews and assesses the current fuel supply infrastructure in terms of reliability for generating capacity.

FRCC entities continue to evaluate new technologies such as FACTS devices and high-temperature conductors to address specific transmission conditions or issues. Presently, there are several transmission lines constructed with high-temperature conductors within FRCC. However, at this time there are no FACTS devices installed within the Region. FRCC Transmission Owners (TOs) consider enhancements to existing transmission planning tools (e.g., enhancements to existing software, new software, etc.) to address the expected planning needs of the future.

Entities within FRCC are taking many steps to reduce protection system misoperations. Some major steps are:

[167] This study is not available to the public due to the inclusion of CEII information.
[168] https://www.frcc.com/handbook/Shared%20Documents/EOP%20-%20Emergency%20Preparedness%20and%20Operations/FINAL%20FRCC%20Generating%20Capacity%20Shortage%20Plan.pdf.

- Improving documentation and actively communicating throughout the Region, by reviewing test procedures and commissioning procedures to ensure there are no "gaps," then sharing these methods with all entities within the Region;
- Improving the relay setting preparation process by sharing data through the FRCC working groups and using field-measured line impedances where practical;
- Reviewing corrective action plans for effectiveness;
- Reviewing NERC and FRCC lessons learned and discussing practical examples;
- Reviewing and implementing vendor service bulletins, including Firmware upgrades, and discussing misoperations with peers.

Procedures have been put in place to reduce human error affecting misoperations, by implementing settings with written, vetted procedures and considering field implementation as a last line of defense to abate human error.

Many entities within FRCC have implemented a capital improvement process, replacing legacy relays with microprocessor relays as each entity's capital budget allows. Entities are refining maintenance by adjusting maintenance practices and maintenance cycles as necessary and applying full-functional testing by direct current injection whenever practical.

FRCC entities thoroughly investigate misoperations to determine the root cause, monitor Protection Systems (alarm contacts, relay voltages, etc.) and review all normal protective system operations for agreement with expected operation-per-settings calculations.

The Florida Coordinating Group's (FCG) Environmental Committee was actively involved in petitioning for judicial review of EPA's final Cross-State Air Pollution Rule (CSAPR), which was to take effect on January 1, 2012. The DC Circuit Court of Appeals placed a stay on CSAPR in late 2011, and ultimately vacated in August 2012.

The EPA's Mercury and Air Toxics Standard (MATS) became effective on April 16, 2012, and requires compliance within three years, with the possibility of a one or two year extension under specific circumstances. Numerous entities around the country have challenged MATS in the D.C. Circuit; it will likely be more than a year before these challenges are resolved. Accordingly, it is still unknown the full impact that MATS or CSAPR, or replacement rules, will have on the long range reliability of the BPS in the FRCC region.

Standing and Emerging Reliability Issues

FRCC has identified one new emerging issue dealing with generation capacity with the potential for serious impact affecting the short-term time frame. Generation capacity could be severely impacted by EPA regulations requiring potential early retirement of existing units and/or unit output derates. The regulations could potentially impact the BPS by requiring new transmission facilities to be constructed to accommodate replacement generation to serve the forecast load with insufficient construction lead time. In the referenced case, resource capacity will decrease to account for potential unit retirement and/or derates. Additional issues that potentially could arise from EPA regulations are the uncertainties of sufficient time frame to replace generation capacity, materials required to retrofit units, and operational issues resulting from alternative dispatch patterns.

MISO

Planning Reserve Margins

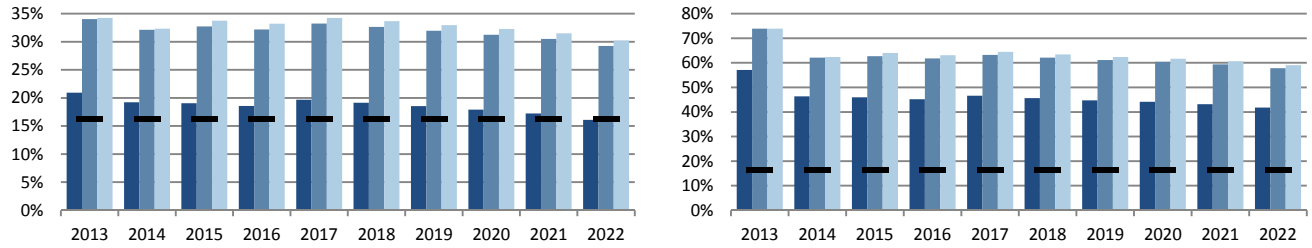
MISO has adequate Planning Reserve Margins throughout the assessment period to meet MISO's Planning Reserve Margin Requirement (PRMR) of 16.3 percent, also applied as the NERC Reference Margin Level (MISO-Table 1 and MISO-Figure 1).

MISO-Table 1: Planning Reserve Margins

MISO-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		20.92%	19.22%	19.04%	18.58%	19.68%	19.15%	18.53%	17.91%	17.24%	16.10%
PROSPECTIVE		34.04%	32.13%	32.73%	32.20%	33.23%	32.64%	31.95%	31.26%	30.51%	29.25%
ADJUSTED POTENTIAL		34.24%	32.33%	33.76%	33.22%	34.25%	33.66%	32.96%	32.27%	31.51%	30.24%
NERC REFERENCE	-	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**

MISO-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		57.13%	46.32%	45.97%	45.17%	46.61%	45.65%	44.74%	44.14%	43.17%	41.78%
PROSPECTIVE		73.89%	62.11%	62.73%	61.82%	63.19%	62.12%	61.10%	60.43%	59.35%	57.80%
ADJUSTED POTENTIAL		73.92%	62.35%	64.02%	63.10%	64.47%	63.39%	62.37%	61.69%	60.60%	59.04%
NERC REFERENCE	-	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**

MISO-Figure 1: Summer (Left) and Winter[169] (Right) Planning Reserve Margins



The Planning Reserve Margin does not fall below the NERC Reference Margin Level during the assessment period. Anticipated Resources may also increase as Existing-Other and Future-Other resources are reclassified to Existing-Certain through MISO's Module E process. This will occur as needed to keep up with load growth while maintaining the PRMR in the final years of the assessment period.

MISO continues to evaluate potential challenges that may exist due to Environmental Protection Agency (EPA) regulations and the gas infrastructure system, which are not included in the Planning Reserve Margins above. EPA regulations may deteriorate projected reserve levels as early as 2015 due to increased retirements to MISO's coal fleet. In addition, as these retired coal units are replaced by other fuel sources, like gas, MISO must evaluate the possible strain on the gas infrastructure system to meet this increased demand. This impact is not included in the Planning Reserve Margins provided below. For more detailed information on the potential impact on reliability due to these and other issues, please read the Emerging Issues section.

Demand

The Total Internal Demand for MISO points to a 10-year CAGR of 1.05 percent, slightly higher than projected one year ago.[170] A diversity factor of 4.61 percent was estimated for 2012. Applying this diversity factor for the period 2013-2022, MISO is able to estimate a Total Internal Demand[171] of 94,279 MW and 103,584 MW for the 2013 and 2022 summers, respectively (MISO-Table 2).[172]

[169] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.
[170] The 2011 LTRA projections shown in Figure 3-1 do not include Duke Energy Ohio or Duke Energy Kentucky load due to their exits from MISO effective January 1, 2012.
[171] This forecast doesn't include the Entergy and its six utility operating companies which will be integrated into MISO footprint by December 2013. The 2011 LTRA forecast was for the period 2011-2021.
[172] MISO projects a high load scenario (90/10) Total Internal Demand of 99,620 MW 109,452 MW for the 2013 and 2022 summers, based on the load forecast uncertainty analysis.

MISO-Table 2: Demand Outlook

MISO-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	89,318	94,875	5,557	6.2%	0.67%
Load-Modifying Demand Response	4,962	8,709	3,747	0.0%	0.00%
TOTAL INTERNAL DEMAND	**94,279**	**103,584**	**9,305**	**9.9%**	**1.05%**

MISO-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	69,663	78,789	9,126	13.1%	1.38%
Load-Modifying Demand Response	2,909	5,105	2,197	0.0%	0.00%
TOTAL INTERNAL DEMAND	**72,572**	**83,894**	**11,322**	**15.6%**	**1.62%**

Approximately 6,000 MW of unrestricted non-coincident peak load was removed from MISO due to the exit of the Duke companies.

The Entergy operating companies Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc. intend to join MISO in December 2013. Total Internal Demand and Net Energy Load for Entergy are not included in the above sections as the current Module E Capacity Tracking[173] tool does not capture the information. MISO is not including Entergy in the *2012LTRA* analysis.

Demand-Side Management

MISO currently separates Load-Modifying Demand Response resources into two separate categories: Interruptible Load (IL) and Direct Control Load Management (DCLM). IL is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. MISO projects IL resources to be 3,883 MW and 6,816 MW for 2013 and 2022, respectively.

DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." During the first year MISO projects DCLM of 1,078 MW, and for the final year of the assessment, MISO projects DCLM of 1,893 MW. Total Demand Response projections for MISO resulted in a CAGR of 6.45 percent from 2013 to 2022 (MISO-Table 3).

MISO-Table 3: Demand-Side Management

	Short-Term					
MISO-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	3,271	3,271	3,271	3,271	0	3.16%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	3,271	3,271	3,271	3,271	0	3.16%
Direct Control Load Management (DCLM)	1,078	1,178	1,268	1,893	814	1.83%
Contractually Interruptible (Curtailable)	3,883	4,244	4,565	6,816	2,933	6.58%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	4,962	5,422	5,833	8,709	3,747	8.41%
TOTAL ENERGY EFFICIENCY	131	382	720	3,922	3,790	3.79%
TOTAL DEMAND-SIDE MANAGEMENT	**8,364**	**9,075**	**9,824**	**15,902**	**7,538**	**15.35%**

Per MISO's Emergency Operating Procedures (RTO-EOP-002), MISO must declare a Maximum Generation Emergency Event Step 2b[174] to gain access to IL and DCLM resources, whereby MISO instructs local Balancing Authorities to reduce load via load-modifying resources as defined in Module E of MISO's tariff.[175]

[173] MISO market participants use the Module E Capacity Tracking (MECT) tool to submit its forecasted Demand and Resources at each Commercial Pricing Node for the upcoming planning years.

[174] Emergency Operating Procedures: https://www.misoenergy.org/MarketsOperations/ReliabilityOperatingProcedures/Pages/ReliabilityOperating Procedures.aspx.

[175] Model E of MISO Tariff (https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx) and Resource Adequacy BPM 011 (https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx).

Generation

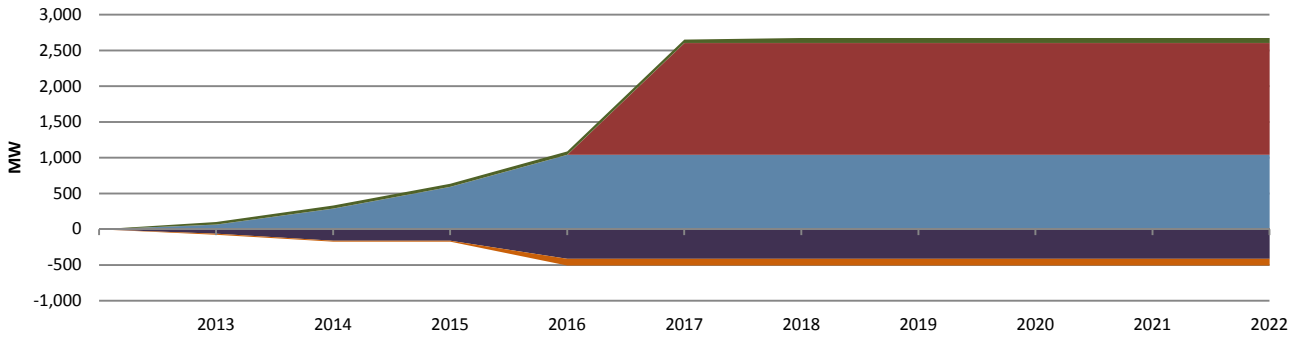
MISO has Existing-Certain resources totaling 101,060 MW for expected summer rated on-peak capacity within its market footprint. Additionally, there is 11,536 MW and 1,588 MW of Existing-Other and Existing-Inoperable capacity, respectively. Since the 2011 summer season, 79 MW of Existing-Certain resources have come into service. This includes 70 MW of wind and 9 MW of gas expected summer rated capacity. The predominant source of fuel in MISO is coal at approximately 55 percent of total existing resources, followed by gas-fired and nuclear generation, totaling 28 and 8 percent, respectively.

Throughout the assessment time frame, MISO anticipates a net total summer rated capacity of 2,197 MW of Future-Planned resources, which includes 202 MW of planned retirements before the 2013 summer season, 71 MW of new wind, 1,069 MW of new natural gas, and 1,563 MW of new nuclear(MISO-Table 4 and MISO-Figure 2).

MISO-Table 4: Capacity Outlook[176]

	Current		2022 Planned			2022 Planned & Conceptual		
MISO	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	55,824	55.2%	55,411	53.6%	-414	55,411	53.6%	-414
Petroleum	4,853	4.8%	4,761	4.6%	-92	4,761	4.6%	-92
Gas	28,298	28.0%	29,367	28.4%	1,069	29,367	28.4%	1,069
Nuclear	8,013	7.9%	9,576	9.3%	1,563	9,576	9.3%	1,563
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	4,134	4.1%	4,204	4.1%	71	4,204	4.1%	71
TOTAL	**101,122**	**100.0%**	**103,319**	**100.0%**	**2,197**	**103,319**	**100.0%**	**2,197**

MISO-Figure 2: Summer Net Capacity Change



Included in total Future-Planned resources are a facility upgrade of an Existing-Certain natural gas combined-cycle plant of 51 MW, a facility replacement of an Existing-Certain coal facility to natural gas with an increase in capacity of 253 MW, and a facility replacement of an Existing-Certain coal and natural gas facility to a natural gas combined-cycle facility with an increase in capacity of 116 MW

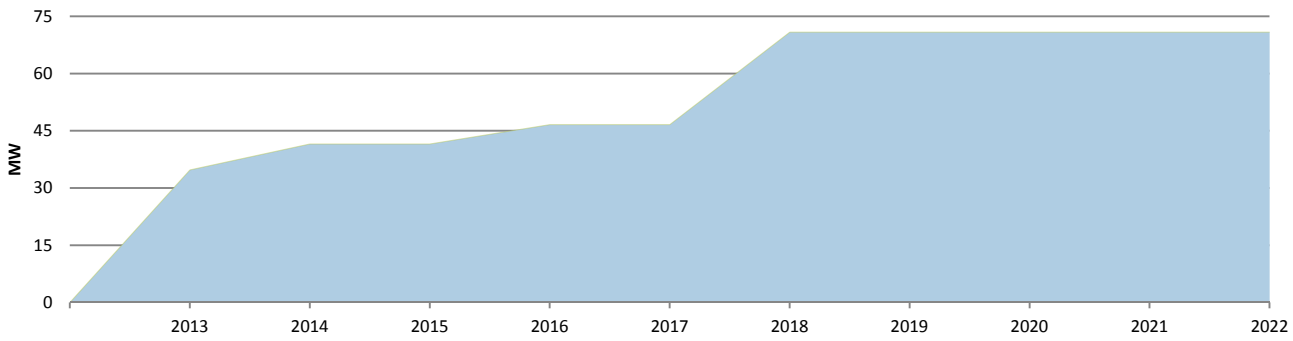
Since the 2011 summer season, MISO's existing capacity was negatively impacted by 4,726 MW of summer rated capacity due to the departure of Duke Energy Ohio and Duke Energy Kentucky from the MISO market on January 1, 2012. The predominant source of fuel from the Duke exit is coal at 78 percent of total Duke Energy Ohio and Duke Energy Kentucky resources. Next is gas at 15 percent and oil at 8 percent. MISO also experienced unit retirements totaling 556 MW in 2011 and 750 MW in 2012 of summer rated capacity since the last reporting year, which was 49 percent coal, 30 percent gas, and 21 percent oil. In addition to membership changes and unit retirements, 160 MW of wind, 10 MW of hydro, and 8 MW of oil resources were pseudo-tied out of MISO since the prior year (MISO-Table 5 and MISO-Figure 2).

[176] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

MISO-Table 5: Renewable Capacity Outlook[177]

	Current		2022 Planned			2022 Planned & Conceptual		
MISO-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	790	19.1%	790	18.8%	0	790	18.8%	0
Pumped Storage	2,288	55.4%	2,288	54.4%	0	2,288	54.4%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	563	13.6%	634	15.1%	71	634	15.1%	71
Biomass	492	11.9%	492	11.7%	0	492	11.7%	0
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**4,134**	**100.0%**	**4,204**	**100.0%**	**71**	**4,204**	**100.0%**	**71**

MISO-Figure 2: Summer Net Renewable Capacity Outlook



MISO expects 148 MW of Existing-Certain and 20 MW of Existing-Other resources to retire before the 2013 summer season, of which the impact on reliability is negligible. This includes 106 MW of coal, 47 MW of gas, and 14 MW of oil resources. In addition, throughout the assessment period, MISO expects 1,099 MW of Existing-Inoperable resources to be removed from suspended or mothballed status and be in service by 2015, which has a positive impact on the Prospective Capacity Resources Reserve Margin of 1 percentage point, keeping the Prospective Reserve Margin above 30 percent in 2015.

Behind-the-meter generation is held flat at the current summer expectation of 3,271 MW throughout the assessment period. Without behind-the-meter generation, MISO's 2022 Anticipated and Prospective Reserve Margins would decrease by 4 percentage points and 3 percentage points, respectively.

The majority of MISO's non-intermittent resources have an Expected Summer on-peak capacity (summer rating) equal to their 2012 Generator Verification Test Capacity (GVTC). More information on the GVTC may be found in the Resource Adequacy Business Practice Manual (BPM) on MISO's website. When a test is not available, the non-intermittent units' Maximum Output from MISO's Commercial Model is utilized.

MISO's wind resources expected on-peak capacity is arrived at by applying a 14.7 percent wind capacity credit to the resources nameplate capacity, and other intermittent resources are given its UCAP rating per the Module E process. The variable capacity outlook for MISO is listed below (MISO-Table 6).

MISO-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
MISO-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	10,791	0	875	599	11,273	0	875	599
On-Peak Derate	10,228	0	85	106	10,873	0	85	106
EXPECTED ON-PEAK CAPACITY	563	0	790	492	634	0	790	492

[177] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Capacity Transactions

MISO only reports Firm power imports that are in the MISO market. The forecast imports are held flat at 3,557 MW throughout the assessment time frame (MISO-Table 7). All these imports are Firm and fully backed by Firm transmission and Firm generation. No imports are based on partial path reservations.

MISO-Table 7: Projected Capacity Transactions

MISO-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557
TOTAL IMPORTS	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**

Transmission

MISO has 273 miles of greater-than-100-kV transmission line under construction, over 90 percent of which is for reliability. MISO expects 1,316 miles of greater-than-100-kV planned transmission line to be in service within five years, of which 530 miles are for the integration of variable/renewable resources, while the remainder is for reliability. As well, 1,571 miles of greater-than-100-kV planned transmission line are expected to be in service within 10 years, of which 866 miles are for the integration of variable/renewable resources, while the remainder is for reliability. All of these projects total 1,844 miles of under-construction or planned transmission expected within the study time frame (MISO-Table 8).

MISO-Table 8: Existing and Projected Transmission

MISO	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	43,291	1,209	44,500
Currently Under Construction	161	0	161
Planned - Completed within First Five Years	1,838	0	1,838
Planned - Completed within Second Five Years	1,069	0	1,069
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	46,359	1,209	47,568
Conceptual - Completed within First Five Years	63	0	63
Conceptual - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**46,422**	**1,209**	**47,631**

Currently, MISO does not anticipate delays in meeting target in-service dates. These projects are anticipated to come into service during the 2012-2022 period to enable reliable and efficient transmission service for MISO. There is no potential reliability impact in not meeting target in-service dates of transmission identified. MISO does not anticipate any existing, significant transmission lines or transformers being out of service through the assessment period. MISO does not have any transmission constraints that could significantly impact reliability.

Vulnerability Assessment

MISO is involved in a variety of smart grid initiatives that will provide increased grid intelligence, use energy in smarter ways, and provide the Region with even greater reliability, efficiency, and sustainability.

MISO uses industry-leading, wide-area uses visualization tools to give system operators a clearer look at system conditions. One of these tools, synchrophasors, provides more precise grid measurements by using data collected from monitors called Phasor Measurement Units (PMUs). PMU measurements are taken at a very high speed (typically 30 observations per second, compared to once every 4 seconds using current technology). PMU measurements are time stamped to time-align (or synchronize) data from widely dispersed locations in the power system network.

In order to plan for 2013 installations, MISO has begun reaching out to Transmission and Generation Owners to identify and confirm additional sites. The placement strategy for 2013 sites will be slightly different from the original placement approach. The new strategy will focus on generator model validation, Transient Stability Analysis, Voltage Stability Analysis, and monitoring of system interfaces.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

MISO conducts quarterly surveys of asset owners' EPA compliance strategies. From the second quarter 2012 survey, 67 out of 103 units totaling 21,893 MW of summer rated capacity will be retrofitting using the dry sorbent injection (DSI) and/or activated carbon injection (ACI) options (MISO-Table 9). Units using these options should have ample time to meet the deadline. Of the remaining units, 8,009 MW will install a combination of FGD, baghouse/fabric filter (FF), and potentially SCR. Most of these units are in the design, permit and constructions phases and should have time to meet the compliance deadline. However, there are a few that have not begun some phases of the retrofit. This could require extensions of the compliance deadline for these units. Additionally, 3,564 MW of capacity has not been committed to a particular technology. The majority of the undecided units are testing for DSI viability. If proven not viable, options become limited and the units will likely require extensions.

MISO-Table 9: Environmental Retrofits by Technology, Resource Type, and Supply Category

			Summer Rating (MW)		Winter Rating (MW)	
Resource Type	Technology	Number of Units	EC	EO	EC	EO
Coal	DSI and/or ACI	**64**	20,218	1,456	20,403	1,462
	FGD	**18**	7,936	74	7,961	74
	FF	**1**	52	-	44	-
	TBD	**17**	3,557	7	3,587	7
Gas	DSI and/or ACI	**2**	174	45	177	45
	FGD	**2**	151	-	193	-
	FF	**-**	-	-	-	-
	TBD	**-**	-	-	-	-
Biomass	DSI and/or ACI	**1**	18	1	18	1
	FGD	**-**	-	-	-	-
	FF	**-**	-	-	-	-
	TBD	**-**	-	-	-	-
TOTAL		**105**	**32,106**	**1,583**	**32,383**	**1,589**

A larger number of units will have "no action required" to comply with the Mercury Air Toxics Standard (MATS) then initially anticipated in the 2011 EPA study effort. In that study, approximately 9,500 MW of capacity was categorized with no action required. However, in the second-quarter survey, asset owners responded "no action required" to meet the MATS amounted to 19,864 MW of capacity. The exact reason for the increase in the no action required category is not known. However, the majority of the increase takes place at units with an electrostatic precipitator (ESP). This technology should be sufficient to meet the particulate matter removal required for MATS, which uses the emission limit for filterable particulate matter instead of total particulate matter.

The remaining units have retired, will be retired, or are in consideration for retirement. From the survey, asset owners have retired 1,706 MW and indicate the intent to retire an additional 2,400 MW of summer rated capacity with another 7,028 MW of capacity on the bubble (MISO-Table 10). If units that did not respond to the survey are included, the retirement figure could reach 12,223 MW. MISO will continue to survey asset owners quarterly.

MISO-Table 10: Retirement Decisions by Resource Type and Supply Category

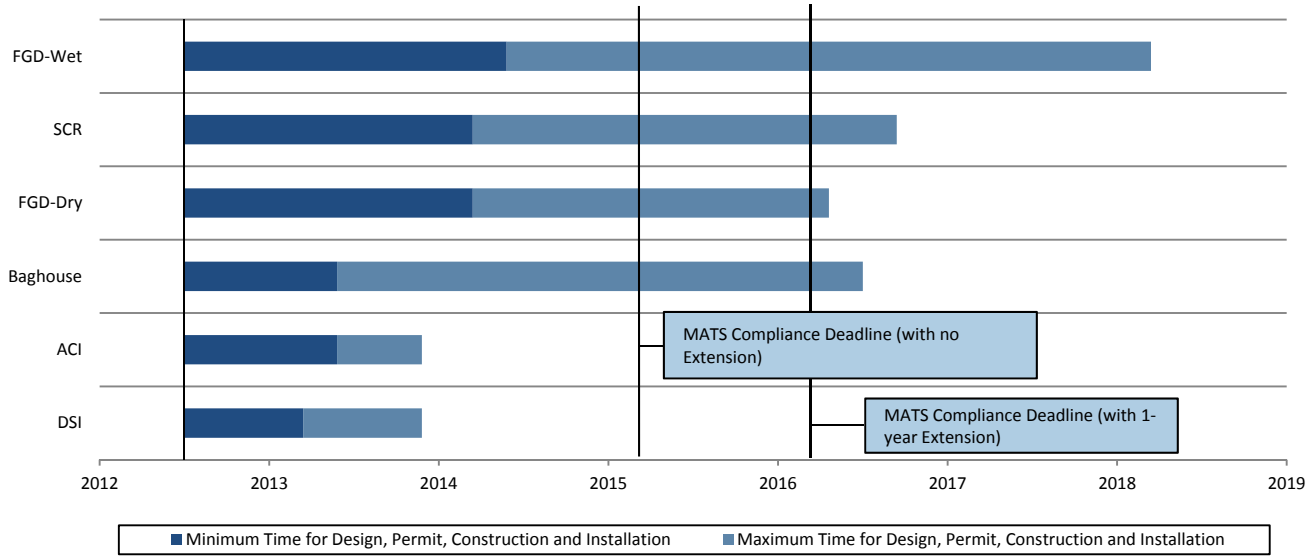
Resource Type	Retirement Decision	Number of Units	Summer Rating (MW)					Winter Rating (MW)				
			Other	EC	EO	FP	FO	Other	EC	EO	FP	FO
Coal	Already Retired	**27**	1,706	-	-	-	-	1,706	-	-	-	-
	Retire	**19**	-	1,022	564	106	394	-	1,040	564	106	394
	TBD for Retire	**49**	-	6,502	176	-	-	-	6,520	176	-	-
	No Action Required	**42**	-	14,719	3,351	-	-	-	14,900	3,371	-	-
	No Response to Survey	**15**	-	482	37	-	-	-	485	37	-	-
Gas	Already Retired	**-**	-	-	-	-	-	-	-	-	-	-
	Retire	**1**	-	158	156	-	-	-	158	156	-	-
	TBD for Retire	**4**	-	295	-	-	-	-	373	-	-	-
	No Action Required	**4**	-	372	4	-	-	-	374	4	-	-
	No Response to Survey	**-**	-	-	-	-	-	-	-	-	-	-
Oil	Already Retired	**-**	-	-	-	-	-	-	-	-	-	-
	Retire	**-**	-	-	-	-	-	-	-	-	-	-
	TBD for Retire	**4**	-	55	-	-	-	-	66	-	-	-
	No Action Required	**-**	-	-	-	-	-	-	-	-	-	-
	No Response to Survey	**1**	-	-	24	-	-	-	-	24	-	-
Behind-the-meter-Generation	Already Retired	**-**	-	-	-	-	-	-	-	-	-	-
	Retire	**-**	-	-	-	-	-	-	-	-	-	-
	TBD for Retire	**-**	-	-	-	-	-	-	-	-	-	-
	No Action Required	**4**	417	-	-	-	-	417	-	-	-	-
	No Response to Survey	**17**	625	-	-	-	-	625	-	-	-	-
Firm Capacity Transactions	Already Retired	**-**	-	-	-	-	-	-	-	-	-	-
	Retire	**-**	-	-	-	-	-	-	-	-	-	-
	TBD for Retire	**-**	-	-	-	-	-	-	-	-	-	-
	No Action Required	**1**	1,002	-	-	-	-	1,002	-	-	-	-
	No Response to Survey	**-**	-	-	-	-	-	-	-	-	-	-

MISO performed EPA analysis using the Electric Generation Expansion Analysis System (EGEAS) software to determine whether retirement or retrofitting would be the most economic option for each generator impacted by the regulations.[178]

The timelines for retrofits vary by technology. Some retrofit technologies - flue gas desulfurization (FGD) and selective catalyst reduction (SCR) - are riskier than others because of the length of time it takes to complete the work and the deadlines for compliance (Figure 3a). It may be possible to receive an additional one-year extension beyond the first year extension, extending the compliance deadline into 2017. This second year extension will likely be limited to unique cases (MISO-Table 11).

[178] A full summary of the analysis is documented in section 4.2 of MISO's MTEP 11 report: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP11/MTEP11%20Report.pdf.

MISO-Table 11: Retrofit Timeline for Various Control Technologies



MISO coordinates the timing of generator (and transmission) outages on the MISO system to maintain reliability. Outage coordination could be affected with the limited number of outage windows. Revisions to the tariff need to take place to address this issue.

Currently, outages in MISO can be rescheduled based on one of the following:

- An emergency
- To maintain nuclear plant interface requirements
- To maintain the Transmission System within System Operating Limits using normal operating procedures or restore the Transmission System to normal operating conditions following a single contingency
- The potential for contingencies to significantly affect Transmission System reliability of metropolitan areas

With the limited outage windows before the 2015 compliance deadline, it will be increasingly important for the outage scheduling group to have has much information as possible. MISO would like to add a fifth rescheduling option to the tariff pertaining to the monthly maintenance margin. The monthly maintenance margin was developed to aid the outage scheduling group and will be updated seasonally.[179]

Standing and Emerging Issues

Environmental Regulations

As a result of the Environmental Protection Agency (EPA) compliance work from 2010-2011, an EPA compliance strategy was developed that would end with possible tariff and market evaluation and adjustments. Several areas of concern that would be included in the EPA compliance strategy were discussed at various stakeholder meetings. Those concerns can be described in four categories: resource adequacy, outage coordination, meeting compliance deadlines, and natural gas infrastructure. Two of the four categories are their own emerging reliability issues: Outage Coordination and Gas and Electric Interdependencies.

The likely impact of this issue will steadily increase as the compliance deadline of 2015 approaches, and MISO anticipates resource adequacy issues to emerge throughout the 2013-2015 period as MISO's market participants determine whether to retire or retrofit units.

[179] https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/EPA_Outage%20Limits%20Analysis.pdf.

The EPA has proposed four regulations that would have potentially profound effects on the power industry's ability to deliver electricity reliably. This compliance may require billions of dollars of investment in new or upgraded facilities to ensure safe and reliable electric service for consumers in the MISO footprint. As a result, MISO may face a capacity shortage if the proposed EPA regulations go into effect.

In the initial evaluation of the impact of the EPA rules on the MISO system, studies were conducted with the Electric Generation Expansion Analysis System (EGEAS) software package developed by the Electric Power Research Institute (EPRI) commonly used by utility generation planners. MISO performed more than 400 sensitivity screens using the EGEAS capacity expansion model to identify the units most at risk for retirement. The sensitivities consisted of variation in costs for natural gas, cost uncertainty risk and retrofit compliance. The results of the EGEAS analysis produced two scenarios, which were 2.9 GW of coal fleet capacity at risk for retirement and 12.6 GW at risk for retirement.

Since the initial evaluation, the four rules have been revised. In response to the revisions, MISO sent out second-quarter surveys to its market participants in 2012 to determine the resource adequacy impact of the EPA regulations. Surveys will continue go out every quarter. From the survey, 4.3 GW of coal capacity responded with the intent to retire, while another 6.3 GW of coal capacity is still in the decision-making stages. If the number of units that did not respond to the survey is included, there is a possibility of 11.9 GW of coal capacity retiring.

If the 4 GW of retirements is experienced, MISO will be able to meet its Planning Reserve Margin Requirements (PRMR) throughout the assessment period. Of the 4 GW of retirements from the survey, 1,706 MW have already retired or have exited the MISO market for reasons unknown to MISO. This leaves 2,400 MW of capacity with the intent to retire during the assessment period. Of this 2,400 MW, 106 MW are Future-Planned retirements, which leaves 2,294 MW. That 2,294 MW is categorized as 1,180 MW of Existing-Certain resources, 720 MW of Existing-Other resources, and 394 MW of Future-Other resources. If these resources retire, MISO has adequate resources to meet its PRMR (target reserve level).

If the 12 GW of retirements is experienced, MISO will be able to meet its Planning Reserve Margin Requirements throughout the assessment period; however, this will be done by relying heavily on Existing-Other resources, which may be subject to fuel availability issues, leading to higher average forced outage rates, transmission limitations, etc. More investigation into resource utilization type is required to understand the true reliability impact. Of the 12 GW of potential retirements, 10,956 MW is included in the LTRA data. Of this 10,596 MW, 106 MW are Future-Planned retirements, which leaves 10,490 MW. That 10,490 MW is categorized as 8,514 MW of Existing-Certain resources, 957 MW of Existing-Other resources, 394 MW of Future-Other resources, and 625 MW of behind-the-meter generation. If these resources retire, the Anticipated Reserve Margins for 2015 and 2022 will be 9.7 percent and 7.1 percent, respectively, and the Prospective Reserve Margin will be 21.9 percent and 18.9 percent, respectively. At this level of retirement, MISO may not have adequate resources to reliably serve load.

For additional information on the impact of EPA retirements on Loss of Load expectation within MISO, see the MTEP 12 report posted on MISO's website.[180]

From the initial EPA study work, it was shown that most of the impact on transmission reliability cost would be relatively small ($30 / kW) and could be implemented within the 2015 period if upgrades are committed early. The upgrades include capacitor bank installations, short lower voltage transmission line additions, modest reconductoring jobs or transformer upgrades at existing stations. However, for some unique situations transmission upgrades would be more involved and would require the need for an extension.

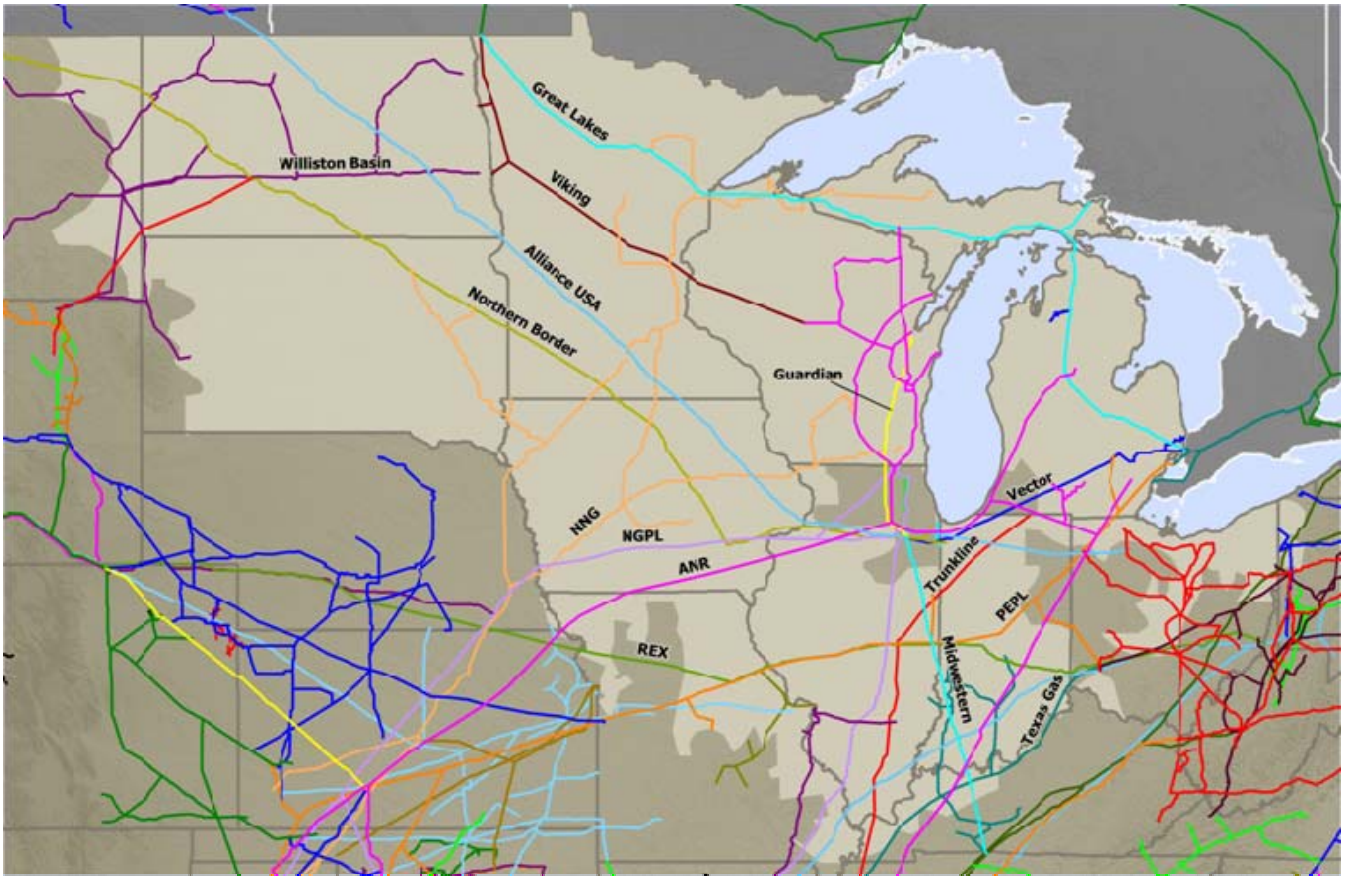
[180] MTEP 12: https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP12.aspx.

MISO is developing a methodology for tracking and projecting emissions. The tool is expected to be complete by the time the CSAPR rule is implemented. Tracking emissions will help MISO staff anticipate potential issues that may arise from the management of the allowances by generating-owning members.

Gas and Electric Interdependencies

New and proposed regulatory compliance obligations will potentially cause the retirement of an estimated 12.6 GW of coal-fired capacity in MISO, causing a shift in the Region's fuel mix. Natural gas-fired plants are expected to replace much of the retired capacity. To prepare for this eventuality, MISO studied gas supply, storage, and pipeline infrastructure to assess how the shift in the electric fuel mix may impact the gas and electric industries over the next 20 years (MISO-Figure 4).

MISO-Figure 4: Overview of MISO Region Major Pipelines



This study[181] demonstrates sufficient gas supply but inadequate mainline capacity to serve the 12.6 GW retirement scenario. Over 65 percent of the pipelines have insufficient capacity to fully meet the needs of the existing units operating at expected capacity factors under the 12.6 GW retirement scenarios. Pipelines sourcing gas supply from the Gulf Coast have significantly higher levels of insufficient capacity compared to southwest and mid-continent pipeline sources. Additionally, shale gas supplies in proximity to MISO will need pipeline flow changes and infrastructure build-out. This analysis is a first step for both the natural gas and electric power industries to better communicate the potential future pipeline capacity availability for gas-fired power generation needs. A collaborative effort among the two industries and regulators is needed to refine pragmatic and practical capacity solutions to meet the future capacity requirements of gas-fired power generation.

[181] https://www.midwestiso.org/Library/Repository/Communication Percent20Material/Key Percent20Presentations Percent20and Percent20Whitepapers/Natural Percent20Gas- Electric Percent20Infrastructure Percent20Interdependency Percent20Analysis_022212_Final Percent20Public.pdf.

MISO performed historical outage analysis for gas-fired units with lack-of-fuel cause codes in the Generation Availability Data System (GADS). The first cause code is for lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels and the second cause code is for lack of fuel with interruptible supply of the fuel part of the fuel contract. Since capacity factors for gas-fired units have historically been low, MISO was able to dispatch base generation units—specifically coal units. However, with increased coal retirements due to EPA regulations, MISO expects to see higher outage rates for gas-fired units.

MISO also performed additional analysis to determine the resulting capacity factors on the gas Combustion Turbines (CTs) and Combined Cycles (CCs) over the 20-year time horizon using the Electric Generation Expansion Analysis System (EGEAS) model, based on a 2011 starting gas price of $2.50/MMBtu and 12.6 GW retirement scenario. For more study analysis on this issue, please refer to the MTEP 12 report posted on MISO's website.[182]

EPA Regulations and Supply Chain

MISO evaluated the risks associated with equipment and labor procurement (supply chain) for various Environmental Protection Agency (EPA) Mercury and Air Toxics Standards (MATS) rule compliance strategies. MISO's supply chain analysis,[183] conducted by The Brattle Group, concluded that the March 2015 timeline requires more construction than the industry has seen in the past, and the greatest unknown risk is the amount of skilled labor available to perform the retrofits. In addition, the type of technology necessary to bring a unit into compliance may require lengthy unit outages that may run past the compliance deadline.

Outage Management Under New EPA Regulations

As part of MISO's efforts to best manage an expected influx of outage requests associated with recent environmental regulations, MISO conducted an outage limit analysis to determine acceptable monthly outage levels that can be allowed to maintain reliable transmission operations.[184]

[182] https://www.midwestiso.org/Pages/Home.aspx.
[183] https://www.midwestiso.org/Library/Repository/Communication Percent20Material/Key Percent20Presentations Percent20and Percent20Whitepapers/Supply Percent20Chain Percent20and Percent20Outage Percent20Analysis Percent20of Percent20MISO Percent20Coal Percent20Retrofits Percent20for Percent20MATS.pdf
[184] https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/EPA_Outage%20Limits%20Analysis.pdf.

MRO-Manitoba Hydro

Planning Reserve Margins

Manitoba is projecting adequate Planning Reserve Margins for the entire assessment period. As a predominately hydro region, Manitoba has both an energy criterion and a capacity Reserve Margin criterion. The capacity Reserve Margin criterion requires a minimum 12 percent reserve above the forecast peak demand. This same criterion is also applied as the NERC Reference Margin Level. Manitoba Hydro uses a series of probabilistic adequacy analysis, with an objective LOLE of 0.1 days per year over a 10-year planning horizon, to review the suitability of the NERC Reference Margin Level above the forecast peak demand.

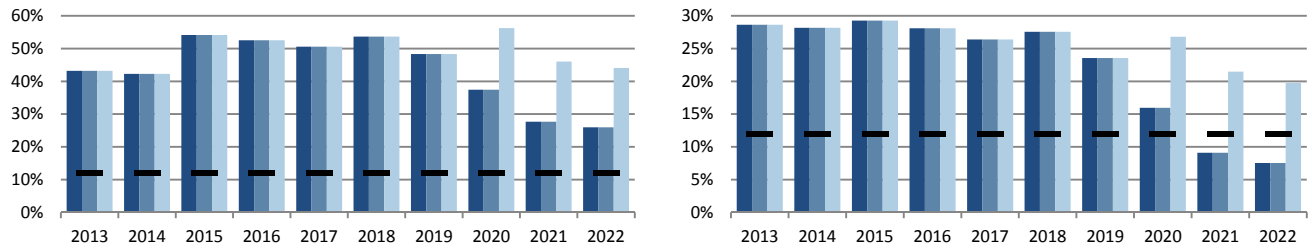
Manitoba Hydro uses an integrated resource planning process with a 35-year planning horizon to plan to meet the long-term needs of the Province of Manitoba. The Anticipated and Prospective Reserve Margins for the winter peak are projected to be below the Reference Margin Level during the 2021-2022 winter seasons. There are expected export sales that are contingent upon Conceptual resources being built. The Anticipated and Prospective Reserve Margins include these expected export sales in their calculations; however, they do not include the expected Conceptual resources. Without the Conceptual resources being built, expected exports would not be realized, and the Anticipated and Prospective Reserve Margins will remain above the NERC Reference Margin level during the winter seasons for the final two years of the assessment period. Should the Conceptual resources be built and the sales realized, Adjusted Potential Reserve Margins are projected to remain well above the NERC Reference Margin Level (MRO-Manitoba Hydro-Table 1 and MRO-Manitoba Hydro-Figure 1).

MRO-Manitoba Hydro-Table 1: Planning Reserve Margins

Manitoba Hydro-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		43.21%	42.26%	54.15%	52.56%	50.60%	53.66%	48.34%	37.45%	27.69%	25.98%
PROSPECTIVE		43.21%	42.26%	54.15%	52.56%	50.60%	53.66%	48.34%	37.45%	27.69%	25.98%
ADJUSTED POTENTIAL		43.21%	42.26%	54.15%	52.56%	50.60%	53.66%	48.34%	56.26%	46.06%	44.11%
NERC REFERENCE	-	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**

Manitoba Hydro-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		28.63%	28.18%	29.28%	28.09%	26.39%	27.56%	23.55%	15.97%	9.10%	7.54%
PROSPECTIVE		28.63%	28.18%	29.28%	28.09%	26.39%	27.56%	23.55%	15.97%	9.10%	7.54%
ADJUSTED POTENTIAL		28.63%	28.18%	29.28%	28.09%	26.39%	27.56%	23.55%	26.81%	21.48%	19.75%
NERC REFERENCE	-	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**

MRO-Manitoba Hydro-Figure 1: Summer (Left) and Winter[185] (Right) Planning Reserve Margins



Assessment projections show ample resources over the next five years, assuming the nearly completed Wuskwatim Generating Station is placed into service by the end of 2012. Beyond the next five years, new resources are likely required, and assessment projections depend on those resources coming into service as planned.

Demand

The compound annual growth rate (CAGR) for Total Internal Demand forecast is 1.14 percent for the winter season and 0.88 percent for the summer season during the 10-year outlook. The slight increase compared to last year's forecast is

[185] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

attributed to higher growth in the residential and commercial sectors, namely from a projected increase in population (MRO-Manitoba-Table 2).

MRO-Manitoba Hydro-Table 2: Demand Outlook

MRO-Manitoba Hydro-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	3,210	3,474	264	8.2%	0.88%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**3,210**	**3,474**	**264**	**8.2%**	**0.88%**

MRO-Manitoba Hydro-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	4,661	5,162	501	10.8%	1.14%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**4,661**	**5,162**	**501**	**10.8%**	**1.14%**

Manitoba Hydro does not expect any significant long-term demand forecast change during the assessment period due to entity acquisitions or exits. Based on the 2011 Economic and Energy Price Outlook, no significant long-term demand change is forecast.

The peak load forecast model has been improved since the *2011 LTRA* with the inclusion hourly data by sector. While the previous model included hourly data at the total system level to determine the load shape for the entire system, the modified approach considers individual load shape all six sectors (Residential All-Electric, Residential Standard, General Service Mass Market, Top Consumers, Distribution Losses, and Transmission Losses). Load growth for each sector is incorporated in the model to determine future load shape and projected peak for the entire system.

Manitoba has a very stable population and a diversified economy with slow but steady growth across the assessment area. The largest customers are in the smelting, chemicals, and pipeline industries and have been operating for decades. Future load growth could be driven by new industries in the area, but are not anticipated at this time.

Demand-Side Management

During the first year of the assessment, the Demand Response used for Ancillary Services–Non Spinning Reserves is 50 MW in 2013. Energy Efficiency and Conservation programs will account for 42 MW for 2013.

During the final year of the assessment, the Demand Response used for Ancillary Services–Non Spinning Reserves remains unchanged at 50 MW. Contractually Interruptible demand response remains unchanged at 225 MW throughout the assessment period. Energy efficiency and conservation programs are projected to increase from 42 MW in 2013 to 419 MW in 2022 (MRO-Manitoba Hydro-Table 3).

MRO-Manitoba Hydro-Table 3: Demand-Side Management

	Short-Term					
MRO-Manitoba Hydro-Winter	2013/14	2014/15	2015/16	2022/23	10-Year Change	2022/23 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	225	225	225	225	0	6.48%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	225	225	225	225	0	6.48%
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	0	0	0	0	0	0.00%
TOTAL ENERGY EFFICIENCY	42	66	88	194	152	5.58%
TOTAL DEMAND-SIDE MANAGEMENT	**267**	**291**	**313**	**419**	**152**	**12.06%**

The Energy Efficiency or conservation growth pattern for Demand Response is expected to be minimal. Current Demand Response implementations are limited to interruptible customer load and are not expected to expand at this time. Demand Response programs are only being used during system contingencies or emergencies. The interruptible customer load may only be used to reduce peak demand if planning and/or contingency reserve obligations are in jeopardy of not being met.

Manitoba Hydro's current Power Smart portfolio includes customer service, cost-recovery, incentive-based and rate-based initiatives, and programs customized to meet the specific energy needs of the residential, commercial, and industrial markets. This portfolio, consisting of Energy Efficiency, conservation, load management, and customer self-generation programs, is designed to help customers conserve energy, reduce energy bills and protect the environment. No specific state or regulatory drivers affect Demand-Side Management (DSM) in Manitoba.

The driver behind all current Dispatchable and Controllable Demand Response programs in place at Manitoba Hydro is to provide operational flexibility for the system operator under emergency conditions. These Demand Response programs are all interruptible customer load for which the industrial customers receive reduced electricity rates in exchange for these services. No significant developments, policy changes, or enhanced implementations to the current programs are expected. The Demand Response program used for Ancillary Services (Non-Spinning Reserves) in place at Manitoba Hydro is the Curtailable Customer Load Option R. Manitoba Hydro has an agreement with a large industrial customer to carry 50 MW of Non-Spinning Reserves in the form of a curtailable customer load.

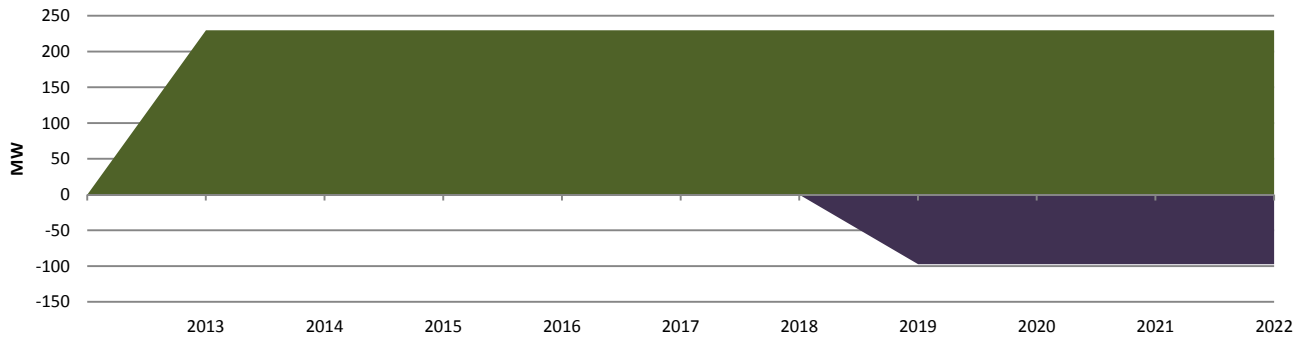
Generation

Current resources in Manitoba total 5,524 MW, with hydro as the primary fuel source in the assessment area. Since last year's assessment, 11 MW of nameplate capacity (hydro) from Kelsey upgrades have been added to Existing-Certain resources (MRO-Manitoba Hydro-Table 4 and MRO-Manitoba Hydro-Figure 2).

MRO-Manitoba Hydro-Table 4: Capacity Outlook[186]

	Current		2022/23 Planned			2022/23 Planned & Conceptual		
Manitoba Hydro-Winter	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	97	1.8%	0	0.0%	-97	0	0.0%	-97
Petroleum	0	0.0%	0	0.0%	0	0	0.0%	0
Gas	395	7.2%	395	7.0%	0	395	6.3%	0
Nuclear	0	0.0%	0	0.0%	0	0	0.0%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	5,032	91.1%	5,262	93.0%	230	5,892	93.7%	860
TOTAL	**5,524**	**100.0%**	**5,657**	**100.0%**	**133**	**6,287**	**100.0%**	**763**

MRO-Manitoba Hydro-Figure 2: Winter Net Capacity Change[187]



Future-Planned hydro generation includes an addition of 22 MW from Kelsey upgrades and 208 MW from the construction of the Wuskwatim Generating Station (both 2012). Also in 2012, an additional 16.5 MW from the St. Leon wind farm is included. Manitoba Hydro's assessment includes 630 MW of conceptual capacity from the Keeyask Generating Station from 2019 to 2020. It is expected that in 2019, the coal unit at the Brandon Generating Station will be retired (approximately 95 MW). Manitoba Hydro uses an integrated resource planning process with a 35-year planning horizon to plan to meet the long-term needs of the Province of Manitoba. Units that are taken out of service during the summer and winter peaks

[186] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[187] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

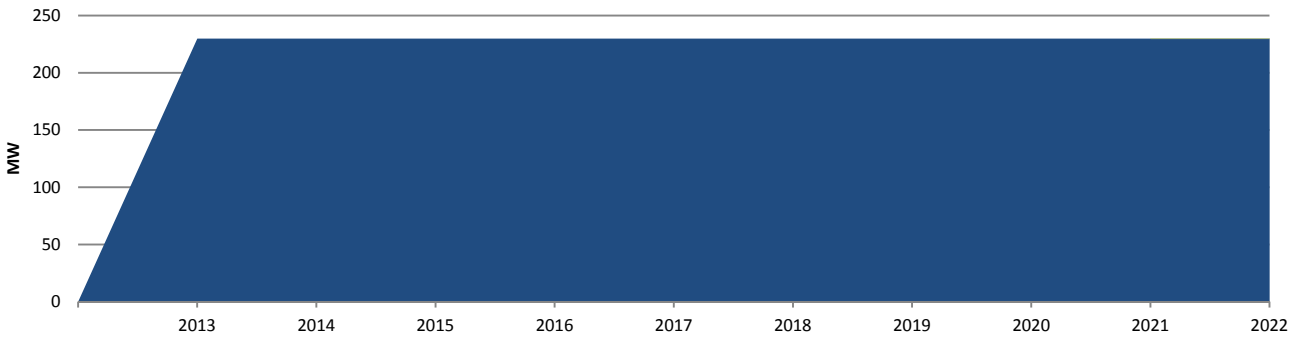
range between 5 MW and 147 MW over the assessment period. Approximately 8 MW of behind-the-meter generation per year is included in the assessment period.

For the 2011 resource adequacy study, wind generation was modeled as a simple load modifier with zero capacity value in the winter (December, January, and February), and an 8 percent capacity credit (19 MW) in the other months. The hydro capacity expected in the on-peak ranges from 4,929 MW to 5,008 MW, depending on the month, as median head conditions vary through the year. The maximum is 5,089 MW, based on nameplate capacity net of station service (MRO-Manitoba Hydro-Table 4 and MRO-Manitoba Hydro-Figure 3). The expected on-peak wind capacity for the summer is 8 percent of the nameplate capacity, and 0 percent for winter on-peak capacity. The expected hydro on-peak values are determined using testing and data processing procedures in accordance with the Midwest Reliability Organization (MRO) Generator Testing Guidelines[188] approved on March 29, 2007.

MRO-Manitoba Hydro-Table 4: Renewable Capacity Outlook[189]

	Current		2022/23 Planned			2022/23 Planned & Conceptual		
Manitoba Hydro-Winter	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	5,032	100.0%	5,262	100.0%	230	5,892	100.0%	860
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	0	0.0%	0	0.0%	0	0	0.0%	0
Biomass	0	0.0%	0	0.0%	0	0	0.0%	0
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**5,032**	**100.0%**	**5,262**	**100.0%**	**230**	**5,892**	**100.0%**	**860**

MRO-Manitoba Hydro-Figure 3: Winter Net Renewable Capacity Change[190]



The expected on-peak capacity that a unit can sustain is computed using the test results. These values are adjusted for ambient conditions and do not include any capacity utilized for station service. For reservoir hydro units, the values are corrected to the five-year median head for each month, while for run-of-river hydro units, the calculation is the average net integrated hourly capability for all hours of historical operation for each month (MRO-Manitoba Hydro-Table 5).

MRO-Manitoba Hydro-Table 5: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022/23 Planned			
MRO-Manitoba Hydro-Winter	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	259	0	5,170	0	275	0	5,400	0
On-Peak Derate	257	0	0	0	272	0	0	0
EXPECTED ON-PEAK OUTPUT	1	0	5,170	0	3	0	5,400	0

Operational procedures will be adjusted gradually as the wind penetration level is increased in the Manitoba Hydro footprint. The potential operational impact of increased wind includes reserve increases and automatic generation control (AGC) sensitivity. Wind forecasting methodologies have been studied for increasing levels of wind penetration, and various

[188] http://www.midwestreliability.org/03_reliability/06_gtrtf/Documents/MRO_Generator_Testing_Guidelines.pdf

[189] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[190] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

recommendations have been made for improvements, depending on the level of penetration studied. Recommendations for improvement include a probabilistic-based forecast approach, as well as decreasing the forecast time step to sub-hourly intervals.

Capacity Transactions

All of Manitoba Hydro's dependable exports and imports are backed by contracts. Manitoba Hydro has between 325 and 550 MW of Firm on-peak capacity exports and between 350 and 500 MW of Firm on-peak capacity imports in the winter and between 725 and 1080 MW of on-peak capacity exports in the summer and associated Firm transmission reservations during the assessment period (MRO-Manitoba Hydro-Table 6). Manitoba Hydro does not have any capacity imports during the summer. These contractual agreements have Firm transmission reservations associated with them with agreements that have staggered terms. Manitoba Hydro does not project any capacity transactions beyond the contract terms; however, in some cases contracts are expected to be rolled over with similar terms. Some future capacity export transactions are contingent upon additional resources being built.

MRO-Manitoba Hydro-Table 6: Projected Capacity Transactions

MRO-Manitoba Hydro-Winter	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	200	200	200	200	200	200	200	200	200	200
Firm Imports	500	500	350	350	350	350	350	350	350	350
TOTAL IMPORTS	700	700	550	550	550	550	550	550	550	550
Expected Exports	0	0	0	0	0	0	0	250	475	475
Firm Exports	550	550	325	325	325	325	325	325	325	325
TOTAL EXPORTS	550	550	325	325	325	325	325	575	800	800
TOTAL NET CAPACITY TRANSACTIONS	**150**	**150**	**225**	**225**	**225**	**225**	**225**	**-25**	**-250**	**-250**

The Manitoba Hydro system is interconnected to three external systems: the MISO system to the south in the United States, and two other Canadian electric power systems, Saskatchewan Power Corporation and Ontario Independent Electricity System Operator. In a resource adequacy assessment, Manitoba Hydro considers non-Firm import as reserve sharing only from the United States (Western MISO Region), but not from other neighboring Canadian utilities. The reserve sharing with the United States is assumed to be possible only if the Western MISO Region system has adequate resource, meaning that the LOLE of Western MISO Region system is not worse than 0.1 days per year.

Transmission

Transmission projects expected to be completed in the Manitoba Assessment Area during the long-term outlook for this assessment are listed in Appendix II. Additionally, a summary of existing and projected transmission additions is provided below (MRO-Manitoba Hydro-Table 7).

MRO-Manitoba Hydro-Table 8: Existing and Projected Transmission

MRO-Manitoba Hydro	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	6,340	1,145	7,485
Currently Under Construction	0	0	0
Planned - Completed within First Five Years	237	0	237
Planned - Completed within Second Five Years	243	833	1,076
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	6,820	1,978	8,798
Conceptual - Completed within First Five Years	0	0	0
Conceptual - Completed within Second Five Years	80	0	80
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**6,900**	**1,978**	**8,878**

A fourth transformer addition at Cornwallis Station is required and planned to provide Firm capacity to the Brandon Area due to restricted operation of the Brandon Unit 5 coal-fired generator. New provincial legislation aimed at greenhouse gas reduction only allows operation of the coal unit under emergency or drought conditions. There are plans to extend Cornwallis Station to accommodate a fourth 230-115 kV transformer and a new 230 kV breaker. Also planned are upgrades and re-routing of 115 kV transmission lines BE3 (Brandon–Brandon Victoria), CB3 (Cornwallis–Brandon), MR11 (Raven Lake–Brandon Victoria), and CB4 (Cornwallis–Brandon). Installation of the fourth transformer and associated transmission line upgrades are estimated to be in service by May 2013. A new 500/230 kV Riel Station consists of establishing a new station, which will involve:

- Installing a 230 kV to 500 kV transformer bank

- Sectionalizing the existing Dorsey–Forbes 500 kV line
- Sectionalizing two existing 230 kV lines (Ridgeway–St. Vital lines R32V and R33V and Ridgeway–Richer Line R49R)

Winnipeg Area Transmission Refurbishments consist of an estimated 113 miles of 230 kV transmission lines that will be upgraded to carry higher loading. Several new 230/115 kV and 66 kV transformers are being added to the system. The sites include Rockwood, Transcona, Stanley, and Neepawa stations. The Rosser–Parkdale–Selkirk 115 kV Transmission System project consists of development of the new 230/115 kV Rockwood Station supplied from the sectionalized Ashern–Rosser 230 kV transmission line A3R (Ashern–Rosser). A 230/115 kV transformer and associated structural and electrical apparatus will be needed to connect this new station to the existing 115 kV system.

The Scotland (now called Stafford) Station rebuild is required in order to provide additional capacity to the core Winnipeg Area and to facilitate the replacement of aging equipment at Scotland Station. The Scotland 138 kV and 115-66 kV Terminal Station is going to be rebuilt. This will involve reusing four 138-66 kV transformers, two 115-66 kV transformers, installing two new 125 MVA 115-66 kV transformers, and new 66 kV and 115 kV ring buses. In addition, the 138 kV transmission systems between Pointe Du Bois, Slave Falls, and Scotland will be converted to 115 kV so that the former Winnipeg Hydro transmission can be integrated into the Manitoba Hydro 115 kV system. Pointe Du Bois 138-66 kV Bank 7 will be replaced by a new 115-66 kV 60 MVA bank to accommodate the voltage conversion. Finally, the termination of lines YH33 (Laverendrye–Harrow) and VS27 (St. Vital–Scotland) will be relocated from Harrow to the new Stafford Station. The scheduled in-service date is estimated to be 2014.

Pointe du Bois transmission line replacement consists of retiring four 66 kV Pointe du Bois–Rover transmission lines on two parallel sets of steel towers that cover 77 miles. The lines were first installed in 1910 and have reached the end of their life. They will be replaced with a new 115 kV line that will run from Pointe du Bois to Whiteshell Station. Several other system modifications are required to accommodate this, including:

- Advance construction of a new 115 kV switchyard at Pointe du Bois.
- Installing a new 66 kV Line from Ridgeway to Rover, including terminations at both stations
- Salvaging two 115-66 kV banks at Transcona Station.
- Increasing the rating of 115 kV Slave Falls transmission lines designated S1 & S2 (Slave Falls–Scotland).

Manitoba Hydro is planning to establish a new 230-66 kV station at Neepawa and tap the existing line D54C (Dorsey–Cornwallis). This project has been delayed for two years due to budget constraints.

The deferral of the Neepawa 230-66 kV Station combined with the proposed new pipeline load in the area increases the risk of under-voltage conditions for outages of either line MR11 (Ravern Lake–Brandon Victoria) or BN5 (Brandon–Neepawa). Operating guides will be put in place as required. Brandon Generating Station Unit 5 was modified in December 2010 to permit synchronous condenser operation, which provides additional local area voltage support.

The Bipole III transmission line from Keewatinoow Converter Station in the north to the Riel Converter Station near Winnipeg will have sufficient capacity to support the Future-Planned Keeyask 630 MW generation plant. The Bipole III routing project on the west side of the province includes:

- ±500 kV HVdc transmission line, about 833 miles long, from Keewatinoow Converter Station to Riel Converter Station
- 2,000 MW converter station at Keewatinoow near the future Conawapa Generating Station
- five ac transmission lines each approximately 19 miles in length to connect the Keewatinoow Converter Station to the existing northern ac collector system
- 2,000 MW converter station at Riel, including 4 x 250 Mvar synchronous compensators

Other significant substation equipment to be added within the Manitoba Assessment Area includes:

- Brandon Generating Station 54 Mvar 115 kV capacitor (4th) (October 2012)
- Riel 230 kV 3 X 73.4 Mvar capacitors (May 2014)

- Keewatinoow and Riel—2000 MW converters at each station (October 2017)
- Riel synchronous condensers (4 X 250 Mvar) (October 2017)
- Dorsey 150 Mvar line reactor—new (May 2018)
- Dorsey bank 51, second stage 73.4 Mvar tertiary capacitors (May 2018)
- Riel 2nd 230/500 kV transformer bank with 2 x 73.4 Mvar tertiary capacitors (May 2019)

Vulnerability Assessment

Several factors could potentially impact the performance adequacy of the Manitoba Hydro system. The primary concerns include extended drought conditions, increased generating unit forced outage rates, and load forecast uncertainty in load forecast beyond that anticipated.

Manitoba Hydro considers extended drought conditions in planning resources and evaluating system resource adequacy. Manitoba Hydro uses an energy criterion for extended drought conditions. The criterion requires adequate energy resources to supply Firm energy demand in the event that the lowest recorded coincident river flow conditions on the available historic hydraulic flow record are repeated. In addition, hydro units are modeled as energy limited resources in the probabilistic resource adequacy study with the energy limits for the applicable cases based on drought or extreme drought conditions.

Generating unit forced outages are considered in the probabilistic resource adequacy studies. Sensitivity analysis on the hydro units forced outage rates of the hydro units that predominate in Manitoba Hydro's system indicates low impact on Planning Reserve Margin Requirements.

Generally, a higher reserve capacity is required in order to maintain a specified level of reliability for an uncertain load than for a known load. Uncertainties in the economy, weather, and temperature would impact the accuracy of forecast load. Probabilistic resource adequacy studies on the Manitoba Hydro system indicate that the load forecast uncertainty negatively impacts Manitoba Hydro's system resource adequacy.

Manitoba does not have a Renewable Portfolio Standard (RPS). Considering that Manitoba's typical energy production is already 98 percent renewable, the potential for a provincial RPS is very low.

Manitoba Hydro currently has approximately 200 MW of Demand Response under Options A, C, E and R of its Curtailable Rates Program. Due to modeling complexities combined with uncertainty as to the customer's long-term commitments to the Curtailable Rates program, these Demand Response resources were not considered in the pending 2012 resource adequacy study. While this assumption is conservative for now, its appropriateness will be reviewed for future LOLE studies. There are no resource adequacy concerns for unavailable/unresponsive Demand Response programs in Manitoba Hydro. The most significant operational concern for this scenario is the need to carry contingency reserves elsewhere when the non-spinning reserves normally available as Demand Response are unresponsive. In addition, when interruptible customer load is unavailable, system operators will have to rely more heavily on emergency energy purchases prior to shedding Firm load under severe system contingencies.

The most likely increase in variable generation in the foreseeable future is wind-related. The addition of new resources would help with resource adequacy issues, and the addition of plausible amounts of wind generation does not raise any significant operational concerns, given the significant operating flexibility of the existing hydro resources.

Currently Manitoba Hydro does not have any Under-Voltage Load Shedding (UVLS) relays installed and has no plans to install any in the 10-year planning horizon.

A new SPS is planned to be installed at Grand Rapids Generating Station. When north-to-south transfers are high in Manitoba, there is potential to thermally overload one or more of the Grand Rapids Generating Station outlet lines when one of the four generator outlet line trips. The SPS will convert one of the Generating Station units to a synchronous

condenser within two minutes of an outlet line tripping, thus preventing line overload while maintaining dynamic var reserves. This will be a permanent solution.

A new SPS is also planned to be installed at Raven Lake Station on 115 kV line MR11 (Raven Lake–Brandon Victoria). When north-to-south transfers in Manitoba are high, there is potential to thermally overload this line for loss of the 230 kV line C28R (Cornwallis–Reston). Over-current tripping of line MR11 will be initiated to alleviate the thermal overload issue. This will be a permanent solution.

Manitoba Hydro has conducted an assessment of vulnerabilities considering low probability extreme weather events and other hazards, such as fires. These low probability events could result in catastrophic outages. Manitoba Hydro has evaluated the risks of these extreme disturbances and associated consequences and has determined that the consequences are too great to be ignored. To mitigate these low-probability and high-impact events and improve system reliability, an additional transmission line located on a separate corridor and associated facilities is planned to provide an alternative north-to-south transmission route and power injection point in the south of Manitoba. Reliability enhancement against fire risks is also in progress.

Manitoba Hydro has already deployed Static Var Compensators (SVCs) at several stations to improve system reliability. A number of Phasor Measurement Units (PMUs) have also been deployed at various points on Manitoba Hydro system, and a data analysis tool is being used to process the collected data to improve system simulation models and fine tune controls. Future plans include the use of PMU data for real-time visualization and decision support tools for system operators. Short-term plans to increase reliability through the use of technology include dynamic security assessment, dynamic equipment ratings, advanced equipment monitoring, and fault current mitigation.

There are no significant smart grid programs currently planned at the distribution level that would impact reliability of the transmission in the bulk power system.

Manitoba Hydro's generation portfolio is dominated by over 95 percent hydro-powered generation. Future plans for new hydro generation to satisfy reliability concerns do not experience the same environmental limitations as the fossil fuel-based alternatives. No significant future environmental regulations will have an impact on reliability.

Operation of the coal-fired Brandon Generating Station is restricted to use for emergency preparedness only, for reliability and staff training purposes. There is sufficient time to perform required retrofits on the coal-fired Brandon Generating Station when the greenhouse gas regulations are introduced and clarified, since it is anticipated that enough lead time will be given to allow for appropriate mitigation.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

Operation of the coal-fired Brandon Generating Station is restricted to use for emergency preparedness only, for reliability and staff training purposes. There is sufficient time to perform required retrofits on the coal-fired Brandon Generating Station when the greenhouse gas regulations are introduced and clarified, since it is anticipated that enough lead time will be given to allow for appropriate mitigation.

The Climate Change and Emissions Reductions Act was enacted by the Province of Manitoba. Since January 1, 2010, provisions under the act have restricted the use of coal generation electricity except in support of emergency operations and drought. In addition to meeting any emergencies, the one remaining coal unit, Brandon Unit #5, may be also be operated to provide for staff training and unit testing to ensure that the unit is maintained in a ready state.

The Government of Canada has a national Greenhouse Gas Emissions Reporting Program (GHGRP). This program applies to the industrial greenhouse gas emitters in Canada. Starting in 2009, all facilities that emit the equivalent of 50,000 tonnes or more of greenhouse gases in carbon dioxide equivalent units per year are required to report their emissions.

Manitoba Hydro has a comprehensive greenhouse gas management strategy to reduce emissions. Actions taken to date include retiring four coal units, converting and additional two coal units to gas-fired operation, developing new hydropower

and wind, and increasing the efficiency of our generation and transmission system. Another key component of this strategy is Manitoba Hydro's long-term commitment to demand-side efficiency improvements through its PowerSmart programs.

Current plans count on the one remaining coal-fired unit, Brandon Unit #5, until 2019. However, depending on various considerations, the unit may continue to provide emergency services beyond this time frame.

There are no anticipated reliability impacts associated with the US environmental regulatory requirements for Manitoba Hydro.

Standing and Emerging Reliability Issues

Each of the three reliability issues identified above is further assessed below.

1. Critical Infrastructure Protection – Extreme Weather Event

This was reported in the *2011 LTRA*; NERC's Technical Committees set up several task forces to investigate high-impact, low-probability events (Spare Equipment data TF and Severe Impact Restoration TF).

The *2012LTRA* Reference case incorporates plans to address the reliability issue. A severe event, such as a naturally occurring hazard (tornado, ice storm), could severely limit the north-to-south transfer capability in Manitoba, which could result in long-duration rotating blackouts in Manitoba.

Significant loss of transmission due to a corridor loss or station loss can restrict the ability of large amounts of generation to serve load.

This issue directly affects transmission adequacy. Generation-to-load transfer capability would be severely diminished for a duration that depends on the underlying cause.

This type of event includes loss of an entire substation and/or loss of a transmission corridor. These events could be caused by extreme weather (fire, tornado, ice storms) or sabotage. These events could cripple operation of the Bulk Electric System (BES) in Manitoba. Manitoba Hydro has operated to protect against a severe disturbance when the likelihood of an extreme weather event has increased to a certain threshold. For example, Manitoba Hydro has developed a "Hydro Proximity Report" application that monitors storm events and their proximity to key infrastructure. If the "Hydro Proximity Report" indicates that a tornado or other strong wind event is threatening key infrastructure, Manitoba Hydro will reduce transfers to ensure that the severe event will not cause Manitoba Hydro to lose its interconnection ties.

Additional Information – Preparedness for Extreme Weather Events

Severe events, such as loss of an entire substation or transmission corridor, are low in probability but can have major consequences, such as long-duration rotating blackouts. An assessment of the vulnerability of Manitoba's facilities to extreme weather and other disturbances was conducted, and it was determined the risk was too great to be ignored. To date, Manitoba Hydro has not experienced any reliability issues associated with high-impact, low-probability events. To mitigate these potential reliability concerns, plans are in place to construct an additional north-to-south transmission line on a separate corridor by 2017. Until these facilities are in place, severe weather is monitored in the operating horizon. Power transfers on the north-to-south flow facilities are reduced if the severe weather is threatening key infrastructure. Loss of these facilities at reduced loading will prevent cascade tripping.

2. Geomagnetic Disturbances

This was reported in the *2011LTRA*. The NERC Planning Committees set up a task force to investigate the impact of geomagnetic disturbances on the grid.

The *2012LTRA* Reference case does not include any specific plans to address the issue. A severe geomagnetic disturbance is forecast to occur roughly coincidental with the peak of sunspot activity that occurs every 12 to 13 years. The last peak in sunspot activity occurred between 2000 and 2003. The next peak is forecast between 2013 and 2016. The geomagnetic disturbance causes dc current to flow in neutral grounded transformers, which can saturate the banks and lead to

shortages of reactive power. Manitoba Hydro analysis conducted to date has indicated that geomagnetic disturbance could impact parts of Manitoba Hydro's 230 kV northern network. The potential impact has not been quantified.

The DC current caused by geomagnetic disturbances can cause transformer equipment damage or misoperation of Static Var Compensators. Manitoba Hydro has developed special equipment specifications and test procedures to minimize this possibility. Monitoring equipment is placed strategically to quantify the magnitude of DC current and notify system operators. Research is underway to develop better analysis tools for determining whether further mitigation is warranted or new operating procedures are required.

Manitoba Hydro has developed operating procedures to minimize the impact of a geomagnetic disturbance. These procedures are implemented once the Reliability Coordinator notifies Manitoba Hydro that an upcoming event has met or exceeded thresholds (per Geomagnetic Disturbance Procedure RTO-OP-053-r4). The Reliability Coordinator receives indices from Boulder, Colorado that indicate the intensity of the geomagnetic disturbance.

3. Integration of Variable Generation

Integration of Variable Generation is a standing issue. This was reported in the 2011 LTRA. The NERC Planning Committee has set up the Integration of Variable Generation Task Force.

The reference case does not include any specific plans to address the issue.

Interconnection of additional variable generation in neighboring Regions to Manitoba changes during the 10-year horizon.

Long-term planning studies indicate potentially significant loop flow in Manitoba due to U.S.-connected wind generation. The loop flow could cause thermal overloads or reduced reactive power reserves in southern Manitoba. In addition, area control error could increase due to the lack of fast-acting regulating reserves in neighboring Regions.

In most studies, transmission is being added only to address Firm capacity levels of variable generation (e.g., 10 to 40 percent of nameplate), which means a significant proportion of the output is non-Firm. Re-dispatch may not be available in the planning horizon to address transmission adequacy issues.

The proliferation of variable resources like wind has introduced complexity into the operating environment. Many wind plants do not build facilities to allow Firm transmission of their wind energy. Loop flow and congestion caused by wind resources outside Manitoba Hydro's service area are the operational issues that arise from integration of these resources. As such, operating guides that curtail wind resources and other resources are used as a mitigating strategy to ensure reliable operations when transmission capacity is exceeded.

MRO-MAPP

Planning Reserve Margins

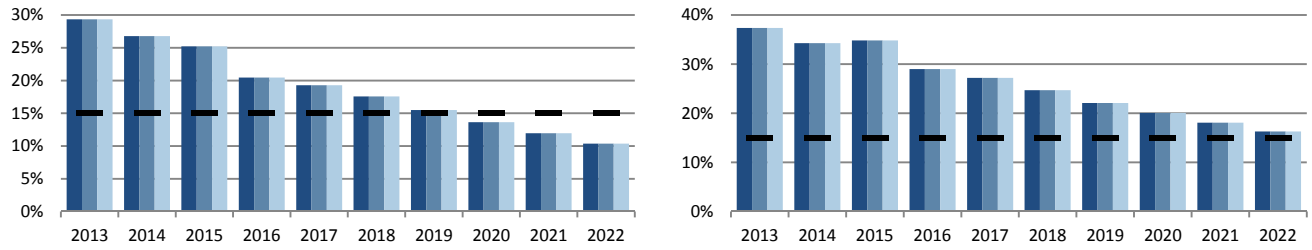
MAPP is projecting adequate Planning Reserve Margins during the 2013–2022 assessment period. All Planning Reserve Margin categories (Anticipated, Prospective, and Adjusted Potential) exceed the NERC Reference Margin Level of 15 percent due to the area's strong generation portfolio and Demand-Side Management programs through 2019 (MRO-MAPP-Table 1 and MRO-MAPP-Figure 1).

MRO-MAPP-Table 1: Planning Reserve Margins

MAPP-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		29.36%	26.79%	25.21%	20.46%	19.28%	17.57%	15.50%	13.65%	11.97%	10.36%
PROSPECTIVE		29.36%	26.79%	25.21%	20.46%	19.28%	17.57%	15.50%	13.65%	11.97%	10.36%
ADJUSTED POTENTIAL		29.36%	26.79%	25.21%	20.46%	19.28%	17.57%	15.50%	13.65%	11.97%	10.36%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

MAPP-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		37.37%	34.28%	34.82%	29.00%	27.20%	24.70%	22.11%	20.07%	18.10%	16.29%
PROSPECTIVE		37.37%	34.28%	34.82%	29.00%	27.20%	24.70%	22.11%	20.07%	18.10%	16.29%
ADJUSTED POTENTIAL		37.37%	34.28%	34.82%	29.00%	27.20%	24.70%	22.11%	20.07%	18.10%	16.29%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

MRO-MAPP-Figure 1: Summer (Left) and Winter[191] (Right) Planning Reserve Margins



The Anticipated Reserve Margin falls below the NERC Reference Margin Level in 2020 and reaches 10.36 percent in 2022. This is a common situation in MAPP, which has traditionally planned to meet the NERC Reference Margin Level at least five to six years in advance, without considerations for additional Firm contracts or new peaking capacity units that have less certainty in the final years of the 10-year assessment. MAPP will provide more accurate plans for 2020–2022 in future long-term assessments, as load projections become more accurate, long-term contracts are executed, and new generation resources are planned. MAPP does not anticipate any scenarios that would lead to a significant detraction from these projections for this assessment period.

Demand

The forecasted 10-year compound annual growth rate for Total Internal Demand remains flat at 2.09 percent for the summer and 2.19 percent for the winter, increasing from 4,995 MW in 2013 to 6,015 MW in 2022 for the peak season (MRO-MAPP-Table 2). This amounts to a 2.09 percent CAGR for the summer demand.

MRO-MAPP-Table 2: Demand Outlook

MRO-MAPP-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	4,904	5,906	1,002	20.4%	2.09%
Load-Modifying Demand Response	91	109	18	19.3%	1.98%
TOTAL INTERNAL DEMAND	**4,995**	**6,015**	**1,020**	**20.4%**	**2.09%**

MRO-MAPP-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	4,858	5,904	1,047	21.5%	2.19%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**4,858**	**5,904**	**1,047**	**21.5%**	**2.19%**

[191] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Certain load-centers (e.g., large cities) are no longer included in the MRO-MAPP Assessment Area. These changes to the assessment area did not have much of an impact on demand growth, which remained essentially unchanged since the *2011LTRA*. There were no changes or enhancements this year to the forecasting methods used by MAPP last year. Most of the MAPP utilities report annual demand growth near the composite MAPP annual growth demand. One localized area of greater load growth is Rochester Public Utilities, which serves the greater Rochester, Minnesota Area and has a forecast 10-year annual growth rate of 6.9 percent for Total Internal Demand. This growth rate is primarily due to the downtown area development of City of Rochester and the expansion of the Mayo Clinic. MAPP continues to monitor the potential impact to demand that may be attributed to the increasing development in the oil and gas production in the Bakken Formation in western North Dakota and eastern Montana. In April 2008, the U.S. Geological Survey (USGS) estimated that the Bakken Formation is larger than all other current USGS oil assessments of the lower 48 states and is the largest "continuous" oil accumulation ever assessed by the USGS.

Demand-Side Management

The total on-peak amount of Demand Response and Energy Efficiency/Conservation projected to be available for 2013 is 129 MW. The total on-peak amount of Demand Response and Energy Efficiency/Conservation projected to be available during the tenth year of the assessment (2022) is 190 MW. The growth pattern for Demand Response is a flat 1 percent throughout the assessment period. The growth pattern for Energy Efficiency / Conservation has more than triple during this assessment period, growing from approximately 22 MW in 2013 to 66 MW in 2022 (MRO-MAPP-Table 3).

MRO-MAPP-Table 3: Demand-Side Management

	Short-Term					
MRO-MAPP-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	5	5	5	5	0	0.09%
Contractually Interruptible (Curtailable)	10	10	10	10	0	0.17%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	16	16	16	16	0	0.26%
Direct Control Load Management (DCLM)	86	88	90	104	18	1.73%
Contractually Interruptible (Curtailable)	5	5	5	5	0	0.08%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	91	93	95	109	18	1.81%
TOTAL ENERGY EFFICIENCY	22	26	31	66	44	1.10%
TOTAL DEMAND-SIDE MANAGEMENT	**129**	**135**	**142**	**190**	**61**	**3.16%**

There have not been any significant changes regarding dispatchable and controllable Demand Response, or Demand Response used for ancillary services in MAPP. The amount of DSM in these areas remains flat.

Generation

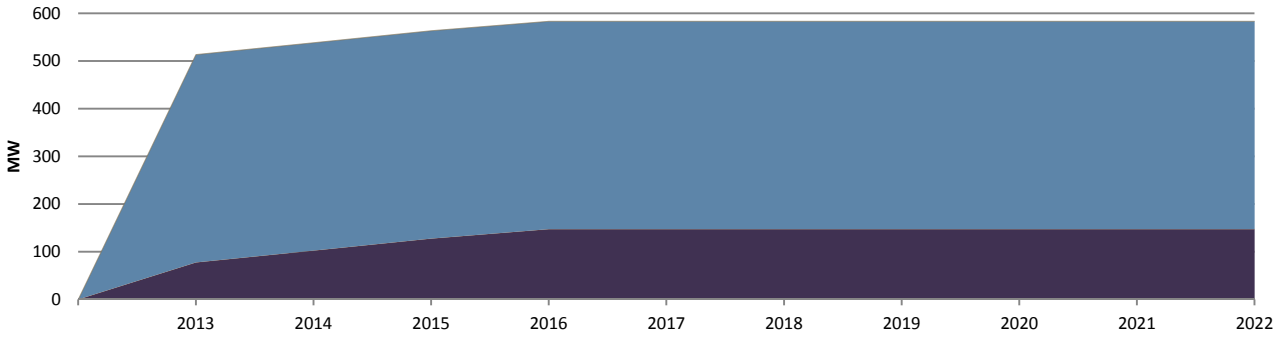
Current capacity amounts to 7,319 MW. There is currently no capacity categorized as Existing-Other or Existing-Inoperable. The primary fuel sources in MAPP are coal, hydro, natural gas, followed by oil and wind. Added capacity since the *2011LTRA* amounts to only about 50 MW.

There are 584 MW of Future-Planned and Conceptual resources projected to come on-line throughout the assessment time frame (MRO-MAPP Table 4 and MRO-MAPP Figure 2).

MRO-MAPP-Table 4: Capacity Outlook[192]

	Current		2022 Planned			2022 Planned & Conceptual		
MRO-MAPP-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	3,174	43.4%	3,322	42.0%	148	3,322	42.0%	148
Petroleum	597	8.2%	597	7.6%	0	597	7.6%	0
Gas	999	13.7%	1,435	18.2%	436	1,435	18.2%	436
Nuclear	60	0.8%	60	0.8%	0	60	0.8%	0
Other/Unknown	41	0.6%	41	0.5%	0	41	0.5%	0
Renewables	2,448	33.4%	2,448	31.0%	0	2,448	31.0%	0
TOTAL	**7,319**	**100.0%**	**7,903**	**100.0%**	**584**	**7,903**	**100.0%**	**584**

MRO-MAPP-Figure 2: Summer Net Capacity Change



There have been no significant unit retirements, deferments, derates, or other negative impact to Existing-Certain capacity in the prior year.

MAPP is not projecting any significant new generation, generator uprates, units taken out of service, units brought back in service, or long-term outages over the assessment period. There has been no change in behind-the-meter generation, or changes in other "non-traditional" resources in the previous year.

Of the total existing capacity, 251 MW of wind generation is expected on-peak, with a nameplate rating of 1,100 MW. To determine wind expected peak, MAPP utilizes a methodology that is based on a median of actual wind output. The same four peak hours per day for each day of the month are used. The four peak hours may change from month to month. This data set consists of 10 years of data or the life of the wind farm. Additionally, there are 2,193 MW of hydro and 3 MW of biomass Existing-Certain Capacity Resources in MAPP (MRO-MAPP-Table 5).

MRO-MAPP-Table 5: Renewable Capacity Outlook[193]

	Current		2022 Planned			2022 Planned & Conceptual		
MRO-MAAP-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	2,193	89.6%	2,193	89.6%	0	2,193	89.6%	0
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	251	10.3%	251	10.3%	0	251	10.3%	0
Biomass	3	0.1%	3	0.1%	0	3	0.1%	0
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**2,448**	**100.0%**	**2,448**	**100.0%**	**0**	**2,448**	**100.0%**	**0**

No abnormal operating conditions or restrictions due to the integration of variable resources are expected to impact reliability during the assessment period. Hydro conditions are expected to be normal, with reservoir levels back to a normal level after several seasons of low water (MRO-MAPP-Table 6).

MRO-MAPP-Table 6: Renewable Capacity Outlook

	Current	2022 Planned

[192] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[193] *Ibid*.

MRO-MAPP-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	1,104	0	2,357	3	1,104	0	2,357	3
On-Peak Derate	853	0	164	0	853	0	164	0
EXPECTED ON-PEAK OUTPUT	251	0	2,193	3	251	0	2,193	3

Capacity Transactions

MAPP is projecting total Firm imports of 307 MW in 2013, increasing to 318 MW by 2022. Additionally, MAPP is projecting total Firm exports of 1,517 MW in 2013, decreasing to 1,424 by 2022. Net capacity transactions remain negative throughout the assessment period (MRO-MAPP-Table 7).

MRO-MAPP-Table 7: Projected Capacity Transactions

MRO-MAPP-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	307	313	319	312	314	316	318	318	318	318
TOTAL IMPORTS	307	313	319	312	314	316	318	318	318	318
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	1,517	1,522	1,493	1,424	1,424	1,424	1,424	1,424	1,424	1,424
TOTAL EXPORTS	1,517	1,522	1,493	1,424	1,424	1,424	1,424	1,424	1,424	1,424
TOTAL NET CAPACITY TRANSACTIONS	**-1,210**	**-1,209**	**-1,174**	**-1,112**	**-1,110**	**-1,108**	**-1,106**	**-1,106**	**-1,106**	**-1,106**

No emergency MW imports are required to meet the reserve margin target in MAPP.

Transmission

MAPP has 230 miles of greater-than-100 kV transmission line under construction and 716 miles of planned transmission projects above 100 kV that are expected to be in service within five years (MRO-MAPP-Table 8). These projects are anticipated to come into service during the 2013–2022 study period to enable reliable and efficient transmission service for the MAPP Assessment Area. There is no potential reliability impact in not meeting target in-service dates of transmission identified. MAPP does not anticipate any existing, significant transmission lines or transformers being out of service through the assessment period. MAPP does not have any transmission constraints that could significantly impact reliability. One transmission project was noted to have permitting delays, but the delays are not expected to impact reliability. Sufficient transmission is being built to support its Future-Planned generation. During the assessment period, several significant transformers are also planned to be upgraded.

MRO-MAPP-Table 8: Existing and Projected Transmission

MRO-MAPP	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	10,266	0	10,266
Currently Under Construction	230	0	230
Planned - Completed within First Five Years	716	0	716
Planned - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	11,211	0	11,211
Conceptual - Completed within First Five Years	107	0	107
Conceptual - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**11,318**	**0**	**11,318**

Vulnerability Assessment

With MAPP's current generation capacity margin and average to high water levels, there are no resource adequacy or operational concerns. Renewable Portfolio Standards (RPS) are not projected to impact reliability in the assessment period.

There are no expectations to install additional Under-Voltage Load Shedding (UVLS) schemes in MAPP. MAPP does not have a regional UVLS requirement. Although Special Protection Systems or Remedial Action Schemes are sometimes utilized in MAPP, none are projected to be installed in lieu of planned bulk power transmission facilities.

MAPP relies on the Balancing Authorities to plan for catastrophic/hi-impact, low-frequency (HILF) events. Currently, there is no regional plan in place.

MAPP and MAPP members continue to research new technologies and tools to improve BPS reliability (e.g., smart grids or FACTS). There is no timeline on deploying new technologies or smart grid programs during the assessment period.

MAPP and MAPP Members continue to work with the MRO and its Subject Matter Expert (SME) teams and their application guides for protection and control to reduce the amount of relay protection misoperations.

The pending future environmental regulations may have an impact on reliability in the MAPP Assessment Area. However, the extent of the reliability impact on the MAPP Assessment Area is unknown until all impacted Generator Owners have announced their plans for compliance with the EPA regulation. MAPP continues both internally and in collaboration with stakeholders to maximize preparedness for the impact of this and other regulations.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

MAPP generators report that they are in compliance with current EPA regulations and Existing Units will be in compliance by the required dates for newly finalized EPA regulations. A few smaller IC units have been retired due to the new regulations, since it would have been cost prohibitive to retrofit the units to meet the regulations.

Generally, MAPP generators are already in compliance or plan to be so by the effective date of EPA regulations. One member reports, emission control technologies have been recently installed and mercury control technology will be optimized 4th quarter 2012 to determine if additional controls will be needed.

One MAPP member has reported it already made the required preparations for integrating its future generation additions. All physical onsite preps have been completed and the permitting and licensing requirements are in process.

MPC reports, the completion of a new 345 kV transmission line at the end of 2013 will allow additional energy from a compliant unit to be brought into Minnkota's service area.

As stated, HUC has retired old generation and new generation is being installed currently.

Heartland has sufficient resource to meet all of its demand and planning margin requirements for the foreseeable future. No new resources, supply or demand side, are planned at this time.

WAPA reports there are plans to uprate the Fort Randall units, which would result in a 28% increase in capacity/unit. However at this time it is unfunded.

Minnkota reports its units are in compliance (earlier than the required date), and is not aware of the need for the assessment.

HUC has done its own internal assessment as to the reliability impact of the new environmental regulations and the current generation plan is the result of that assessment. HUC will perform its own assessments if necessary. Any/all plans are discussed through coordinated meetings with HUC's balancing authority (GRE) prior to implementation.

Standing and Emerging Reliability Issues

Integration of Variable Resources – Planning Perspective

One of the emerging issues within MAPP is the integration of variable resources, such as wind turbines. Many states in MAPP have a renewable energy mandate or goal. It is expected that the primary source of new renewable energy will come from intermittent resources, including wind. The integration of intermittent resources presents new challenges in the Region. The integration does not cause undo reliability issues on its own, but it does change the nature of how the BPS is operated.

As the amount of wind resources increases, its contribution to resource adequacy will also increase. This may introduce additional uncertainty in maintaining system reliability. New wind resources will have an impact on the transmission system and may increase the potential for congestion on the system. Intermittent resources also have an impact on the operation of the system generation fleet as resources will need to be dedicated into meeting the potential ramp and minimum generation issues that could occur.

Currently, wind development is focused around meeting the existing state renewable energy mandates. However, resource adequacy may become a concern if additional regulations or rules (clean energy standards, carbon reduction) are implemented. Additionally, economic factors may increase the amount of intermittent resources found on the system, such as higher gas prices or lower construction costs for the intermittent resources.

Transmission In-Service Dates

Another emerging issue that impacts MAPP as well as other Assessment Areas is the complex process for getting transmission projects built. Transmission projects that do not get built, or get delayed, may impact reliability through congestion on the existing BES. This could impact the amount of transmission loading relief (TLR) used. Currently, this issue is not impacting resource adequacy as reported through the LTRA. A Loss of Load Expectation (LOLE) study may reveal constrained interfaces within MAPP. Siting and permitting issues could be barriers to transmission in-service dates, which may constrain the existing BES and affect real-time operations.

MRO-SaskPower

Planning Reserve Margins

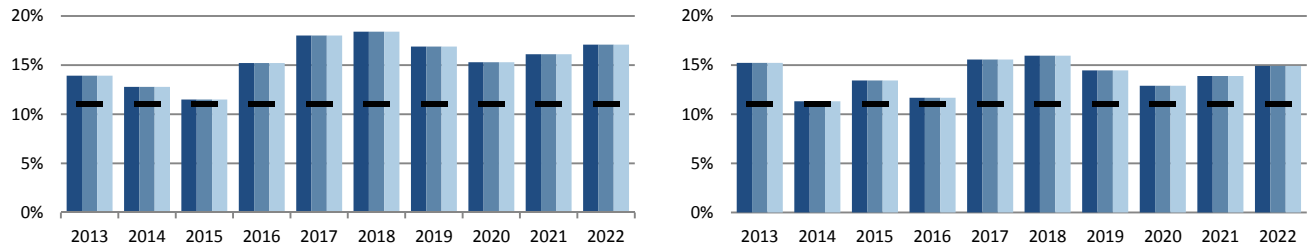
Saskatchewan is projecting adequate Planning Reserve Margins based on Expected Unserved Energy (EUE) analysis. Saskatchewan's criteria for adding new generation resources are also based on EUE. Saskatchewan performs an annual probabilistic analysis to determine the requirement for adding new generation resources. The probabilistic EUE value equates to an approximate 11 to 18 percent reserve margin based on the deterministic calculation (MRO-SaskPower-Table 1 and MRO-SaskPower-Figure 1). When evaluating system requirements for new generation, SaskPower utilizes a most likely load forecast accounting for load risk to project demand requirements. This is not based on a 50/50 probability. For the purpose of this study, utilization of a less conservative 50/50 load forecast probability would result in higher reserve margins ranging from approximately 16 to 23 percent. Furthermore, for the purpose of this assessment, the NERC Reference Margin Level is 11 percent (lower end of probabilistic EUE range) throughout the assessment period. Saskatchewan has planned for adequate resources to meet anticipated load throughout the assessment period.

MRO-SaskPower-Table 1: Planning Reserve Margins

SaskPower-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		13.93%	12.79%	11.51%	15.22%	18.02%	18.41%	16.89%	15.29%	16.11%	17.10%
PROSPECTIVE		13.93%	12.79%	11.51%	15.22%	18.02%	18.41%	16.89%	15.29%	16.11%	17.10%
ADJUSTED POTENTIAL		13.93%	12.79%	11.51%	15.22%	18.02%	18.41%	16.89%	15.29%	16.11%	17.10%
NERC REFERENCE	-	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**

SaskPower-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		15.24%	11.33%	13.43%	11.68%	15.57%	15.97%	14.47%	12.91%	13.90%	14.93%
PROSPECTIVE		15.24%	11.33%	13.43%	11.68%	15.57%	15.97%	14.47%	12.91%	13.90%	14.93%
ADJUSTED POTENTIAL		15.24%	11.33%	13.43%	11.68%	15.57%	15.97%	14.47%	12.91%	13.90%	14.93%
NERC REFERENCE	-	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**

MRO-SaskPower-Figure 1: Summer (Left) and Winter[194] (Right) Planning Reserve Margins



Saskatchewan does not anticipate any challenges that would lead to significant detractions of its Planning Reserve Margin projections. Greenhouse gas regulations are expected to become an issue as specific federal and provincial regulations are introduced and clarified. The consequence of such regulations is expected to have a low impact on reliability, because it is anticipated that enough lead time will be given to allow for appropriate mitigation.

Demand

The forecasted compound annual growth rates (CAGR) Total Internal Demand is 2.12 percent for the summer and 2.04 percent for the winter during the 10-year outlook (MRO-SaskPower-Table 2).

[194] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

MRO-SaskPower-Table 2: Demand Outlook

MRO-SaskPower-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	3,184	3,847	663	20.8%	2.12%
Load-Modifying Demand Response	91	91	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**3,275**	**3,938**	**663**	**20.2%**	**2.07%**

MRO-SaskPower-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	3,580	4,310	730	20.4%	2.08%
Load-Modifying Demand Response	91	91	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**3,671**	**4,401**	**730**	**19.9%**	**2.04%**

Saskatchewan does not anticipate any significant forecast changes. An upswing in the economy could lead to an increase in electricity usage and cause a spike to the overall demand. Saskatchewan has plans in place to meet resource reliability requirements should a sudden economic change cause a need for new capacity. There were no changes or enhancements made to the forecasting methods used by SaskPower. Load growth is due primarily to economic growth in the industrial sector.

Demand-Side Management

It is expected that 150 MW of Demand Response and Energy Efficiency/Conservation will be available during the first year of the assessment. It is expected that 253 MW of Demand Response and Energy Efficiency/Conservation will be available during the tenth year of the assessment. Approximately 10 MW of additional Energy Efficiency/Conservation is expected to be available each year throughout the assessment period (MRO-SaskPower-Table 3).

MRO-SaskPower-Table 3: Demand-Side Management

	Short-Term					
MRO-SaskPower-Winter	2013/14	2014/15	2015/16	2022/23	10-Year Change	2022/23 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	91	91	91	91	0	2.07%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	91	91	91	91	0	2.07%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**91**	**91**	**91**	**91**	**0**	**2.07%**

Saskatchewan considers Demand Response to be a capacity resource used for peak shaving. The primary driver for DSM programs in Saskatchewan is the economic incentive (difference in cost between providing the DSM program and the cost of serving the load). Increases in DSM will come from growth of existing programs.

There are no new Demand Response programs or Ancillary Services being incorporated for the assessment period.

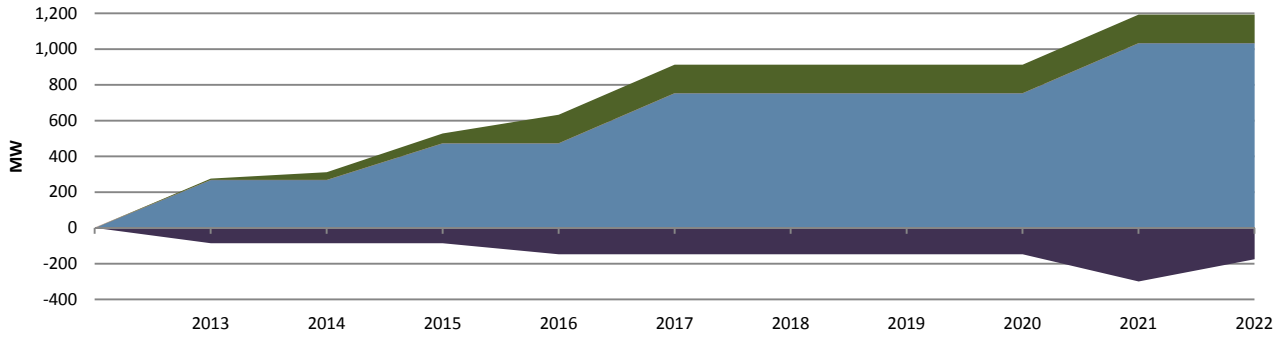
Generation

The primary sources of fuel in Saskatchewan are coal, hydro, and natural gas. Since 2011, 89 MW of natural gas generation has been added in Saskatchewan. Throughout the assessment period, a total nameplate capacity of 1,742 MW of Future-Planned resources are projected to come on-line (365 MW of refurbished coal, 1,034 MW of gas, 230 MW (nameplate) wind, 106 MW of biomass resources), and about 7 MW of additional hydro resources. Saskatchewan manages unit retirements within its resource planning process so that there are no reliability issues related to unit retirements during the assessment period. Unit retirements (coal) during the assessment period include 62 MW in 2013 and 61 MW in 2015 (MRO-SaskPower-Table 3 and MRO-SaskPower-Figure 2).

MRO-SaskPower-Table 4: Capacity Outlook[195]

MRO-SaskPower-Winter	Current		2022/23 Planned			2022/23 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	1,671	42.4%	1,496	30.2%	-175	1,496	30.2%	-175
Petroleum	0	0.0%	0	0.0%	0	0	0.0%	0
Gas	1,361	34.6%	2,395	48.3%	1,034	2,395	48.3%	1,034
Nuclear	0	0.0%	0	0.0%	0	0	0.0%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	907	23.0%	1,066	21.5%	159	1,066	21.5%	159
TOTAL	**3,939**	**100.0%**	**4,957**	**100.0%**	**1,018**	**4,957**	**100.0%**	**1,018**

MRO-SaskPower-Figure 2: Winter Net Capacity Change[196]

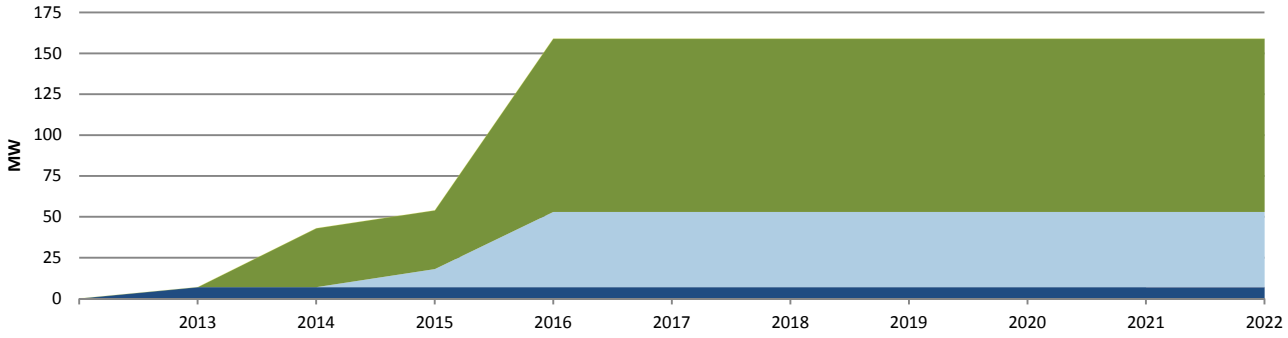


By the final year of the assessment period, about 86 MW (out of 428 MW nameplate capacity) of wind is expected to be available to meet the winter peak, which is over twice the 2013 amount. During the next ten years, 106 MW of biomass is also expected to be added.

MRO-SaskPower-Table 5: Renewable Capacity Outlook[197]

MRO-SaskPower-Winter	Current		2022/23 Planned			2022/23 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	857	94.5%	864	81.1%	7	864	81.1%	7
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	40	4.4%	86	8.0%	46	86	8.0%	46
Biomass	10	1.1%	116	10.9%	106	116	10.9%	106
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**907**	**100.0%**	**1,066**	**100.0%**	**159**	**1,066**	**100.0%**	**159**

MRO-SaskPower-Figure3: Winter Net Renewable Capacity Change[198]



[195] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[196] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.
[197] *Ibid.*
[198] *Ibid.*

For the assessment period, Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet summer peak demand and 20 percent of wind nameplate capacity to be available to meet winter peak demand. The wind available to meet peak requirements is based on the historical actual wind generation over a four-hour period during the peak for each day. On-peak expected values for hydro assume nameplate net generation less expected seasonal derates due to water conditions. Saskatchewan plans for 100 percent of biomass nameplate capacity to be available to meet demand based on a base-load contract. Operational procedures for the assessment period will not be impacted because of integrating variable resources (MRO-SaskPower-Table 6).

MRO-SaskPower-Table 6: Variable Generation

	Current				2022/23 Planned			
MRO-SaskPower-Winter	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	198	0	860	10	428	0	867	186
On-Peak Derate	158	0	2	0	342	0	2	70
EXPECTED ON-PEAK OUTPUT	40	0	857	10	86	0	864	116

Capacity Transactions

Saskatchewan does not anticipate any Firm imports or exports for the assessment period. Saskatchewan does not rely on emergency imports to meet its demand.

Transmission

Major projects expected to be completed in the MRO-SaskPower Assessment Area during the long-term outlook for this assessment are listed in Appendix II and summarized below (MRO-SaskPower-Table7). Additional details and descriptions of particular projects needed to meet transmission adequacy and load growth in the area are included below.

MRO-SaskPower-Table 7: Existing and Projected Transmission

NPCC-Maritimes	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	5,082	0	5,082
Currently Under Construction	0	0	0
Planned - Completed within First Five Years	13	0	13
Planned - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	5,095	0	5,095
Conceptual - Completed within First Five Years	203	0	203
Conceptual - Completed within Second Five Years	50	0	50
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**5,348**	**0**	**5,348**

Autotransformer Additions

- Planned addition of two 230-138 kV autotransformers in the Tantallon Area (eastern Saskatchewan) in late 2012 and 2013.
- The existing 230-138 kV autotransformer in the Tantallon Area will be moved to the Peebles area (eastern Saskatchewan).
- Planned addition of two 230-138 kV autotransformers in the Fleet Street Area (southeastern Saskatchewan) in late 2012 and 2013.
- The existing 230-138 kV autotransformer in the Fleet Street Area will be moved to the Kennedy Area (eastern Saskatchewan).
- Planned addition of two 230-138 kV autotransformers in the Boundary Dam Area (southeastern Saskatchewan) in late 2013 and 2014.
- The existing 230-138 kV autotransformer in the Boundary Dam Area will be utilized as a system spare or moved to another location in Saskatchewan.
- Conceptual addition of 230-138 kV autotransformers in the Condie, Regina, Moose Jaw, North Battleford, Wolverine, and Lloydminster Areas (dispersed in Saskatchewan) in late 2016.

Transmission Line Additions

- Planned addition of a 40 km 230 kV transmission line in the Saskatoon-Martinsville Area (central Saskatchewan) in late 2013.

- Planned addition of a 110 km 230 kV transmission line in the Saskatoon-Wolverine Area (central Saskatchewan) in late 2013.
- Planned addition of 50 km of 138 kV transmission line and salvage of 65 km of 138 kV line in the Elstow-Wolverine Area (central Saskatchewan) in late 2013.
- Planned addition of a 225 km 230 kV transmission line in the Moose Jaw-Swift Current Area (central Saskatchewan) in late 2016.
- Planned addition of 225 km of 138 kV transmission line and salvage of 200 km of 138 kV line in the Moose Jaw-Swift Current Area (central Saskatchewan) in late 2016.
- Planned addition of a 135 km 230 kV transmission line in the Peebles-Tantallon Area (eastern Saskatchewan) in late 2013.
- Conceptual addition of a 160 km 230 kV transmission line in the Beatty-Wolverine Area (north-central Saskatchewan) in late 2016.
- Conceptual addition of a 70 km 230 kV transmission line in Condie-Pasqua Area (south-central Saskatchewan) in late 2016.
- Conceptual addition of a 130 km 230 kV transmission line in North Battleford-Saskatoon Area (south-central Saskatchewan) in late 2016.

At this time, there are no confirmed delays for targeted in-service dates for planned projects, and there are no major concerns with temporary service outages for any existing line or transformer facilities. For planned and emergency outages, further detailed study work is performed and temporary operating guides are issued as required.

Sufficient transmission lines are being constructed to support the Future-Planned resources that are projected to come on-line during the assessment period. Saskatchewan is planning for the addition of a Static Var System (SVS) in the Swift Current Area (southwestern Saskatchewan) in late 2013.

Vulnerability Assessment

Saskatchewan has no resource adequacy or operational concerns during the assessment period. Currently there are plans to install one UVLS scheme in the Tantallon Area in late 2012. This scheme is being installed to mitigate potential low voltages under certain generation dispatch scenarios caused by an N-1 outage (until planned transmission reinforcement in 2015 is in place) and a few N-2 outages. These outages are in the southeastern portion of the province. The planned UVLS scheme targets approximately 40 MVA of load to be shed. This equates to approximately 1 percent of the projected total Saskatchewan 2013 winter peak load. The planned UVLS scheme does not influence this reliability assessment as it is being implemented to mitigate potential local area post-contingency voltage concerns. A new 230 kV transmission line is planned in the Tantallon Area that will reinforce the Tantallon Area voltage. This line has a projected in-service date of mid-2015. The UVLS scheme may then be used to mitigate potential low voltages for N-1-1 and N-2 outages under certain generation dispatch scenarios.

Special Protection Systems in Saskatchewan are typically implemented on a temporary basis until transmission facilities can be added. The following Special Protection Systems are planned in Saskatchewan to address N-2 outages of 230 kV double circuits:

- 230 kV double circuit between the Boundary Dam and Regina Areas.
- Planned in-service date of 2014
- This scheme is intended to be temporary until 2015, when planned generation unit retirements and projected industrial load growth in the southeastern portion of the province materializes.
- 230 kV double circuits in the Nipawin Area.
- Planned in-service date of 2014.
- Permanent for the assessment period.

- 230 kV double circuit between the Saskatoon and Beatty Areas.
- Planned in-service date of 2015.
- This scheme is intended to be temporary until 2016, when the Conceptual Beatty to Wolverine 230 kV line is in service.

Saskatchewan has emergency preparedness plans as mandated by provincial and federal requirements to address catastrophic events in general. Saskatchewan does not specifically plan its system for high-impact, low-frequency events, but assessments may be done on as-needed basis, taking into account the reliability benefit versus cost. In general, the Saskatchewan BES is designed to be fail-safe for most types of contingencies and to be restored as soon as possible. However, operation of the Saskatchewan system would be performed on a best-efforts basis under the types of catastrophic emergency conditions provided as examples. Resources would be offset by planning reserves and external markets as much as possible. If necessary, operational measures would include interruptible load contracts, public appeals, and rotating outages.

Earthquakes and hurricanes are historically not a concern for Saskatchewan. Fuel disruptions are minimized as much as possible by historical system design practices, and Saskatchewan has a diverse energy mix of resources. Coal resources have Firm contracts and are adjacent to generating facilities, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Natural gas resources have Firm transportation contracts with large natural gas storage facilities located within the province backing those contracts up. Coordination meetings between the electric system and the natural gas transportation system are held to discuss operational and planning issues. These meetings enable both systems to be informed of any issues relating to security of supply for natural gas transportation. Hydro facilities/reservoirs are fully controlled by Saskatchewan, and long-term hydrological conditions are monitored. Geomagnetic induced currents have historically not been a problem for Saskatchewan. Loss of a major import path has not historically been a concern for Saskatchewan, as it typically does not rely on imports to serve load.

Saskatchewan evaluates new technologies as they become available and uses them if economical. Saskatchewan does not have any significant smart grid programs that affect the BES. Current efforts are primarily focused on the distribution system. Protection systems are maintained and tested on an on-going basis, and misoperations are evaluated for lessons learned.

No environmental or regulatory restrictions have been identified at this time that could potentially impact reliability in Saskatchewan for the assessment period. Greenhouse gas regulations are expected to become an issue as specific regulations are introduced and clarified. The consequence of such regulations is expected to have a low impact on reliability, because it is anticipated that enough lead time will be given to allow for appropriate mitigation.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

Currently there are no greenhouse gas emission programs or criteria for Saskatchewan. For the assessment period, Saskatchewan has plans to retire five coal-fired generating units. Up to three of the units will be replaced by clean coal generating units. Studies have been performed based on possible greenhouse gas regulations. Analysis to support decision-making will conducted once the regulations are known. Ultimately, no potential reliability impacts or improvements that would arise on the Saskatchewan system have been identified due to the recent US environmental regulatory requirements.

Standing and Emerging Reliability Issues

Greenhouse gas regulation is expected to become an issue in the short-term (one- to five-year period) as specific regulations are introduced and clarified. The consequence of such regulations is expected to have a low impact on reliability, because it is anticipated that enough lead time will be given to allow for appropriate mitigation. Saskatchewan currently relies, in part, on greenhouse gas emitting generation sources such as coal and natural gas. The potential impact

of greenhouse gas regulations would be to reduce Saskatchewan's ability to rely on carbon-emitting fuel sources for future generation requirements. Saskatchewan has developed future scenario plans to deal with anticipated greenhouse gas emissions regulations. Saskatchewan has not yet experienced any reliability issues related to greenhouse gas regulations and is expected to effectively mitigate any future reliability issues related to greenhouse gas regulations. Mitigation will either be reducing greenhouse emissions or replacement of generation.

NPCC-Maritimes

Planning Reserve Margins

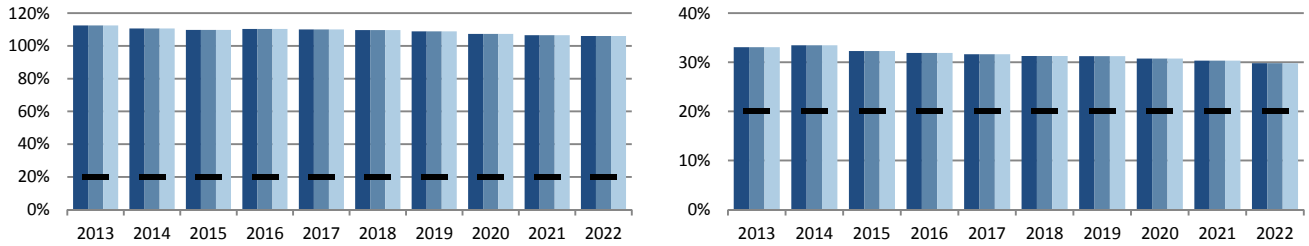
The NERC Reference Margin Level for the Maritimes Assessment Area is 20 percent throughout the assessment period (NPCC-Maritimes-Table 1 and MRO-Maritimes Figure 1).

NPCC-Maritimes-Table 1: Planning Reserve Margins – NPCC-Maritimes

NPCC-Maritimes-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		112.5%	110.6%	109.8%	110.3%	110.1%	109.6%	108.8%	107.3%	106.5%	106.0%
PROSPECTIVE		112.5%	110.6%	109.8%	110.3%	110.1%	109.6%	108.8%	107.3%	106.5%	106.0%
ADJUSTED POTENTIAL		112.5%	110.6%	109.8%	110.3%	110.1%	109.6%	108.8%	107.3%	106.5%	106.0%
NERC REFERENCE	-	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

NPCC-Maritimes-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		33.1%	33.4%	32.3%	31.9%	31.6%	31.3%	31.2%	30.8%	30.3%	29.8%
PROSPECTIVE		33.1%	33.4%	32.3%	31.9%	31.6%	31.3%	31.2%	30.8%	30.3%	29.8%
ADJUSTED POTENTIAL		33.1%	33.4%	32.3%	31.9%	31.6%	31.3%	31.2%	30.8%	30.3%	29.8%
NERC REFERENCE	-	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

NPCC-Maritimes-Figure 1: Summer (Left) and Winter[199] (Right) Planning Reserve Margins



Renewable portfolio standards in the area led to the construction of the existing generation mix. Peak demands in the area have declined from historic highs and combined with the addition of generation resources associated with renewable portfolio standards. All Planning Reserve Margins exceed the NERC Reference Margin Level for the duration of the assessment period.

Demand

The forecast CAGR for peak demand is 0.25 and 0.27 percent for the summer and winter seasons, respectively (NPCC-Maritimes-Table 2). This indicates that aggregated growth will be effectively offset by the sum of any DSM projections or load losses included in the sub-area forecasts.

NPCC-Maritimes-Table 2: Demand Outlook

NPCC-Maritimes-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	3,104	3,183	79	2.5%	0.28%
Load-Modifying Demand Response	331	331	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**3,435**	**3,514**	**79**	**2.3%**	**0.25%**

NPCC-Maritimes-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	5,169	5,285	116	2.2%	0.25%
Load-Modifying Demand Response	252	267	15	6.0%	0.64%
TOTAL INTERNAL DEMAND	**5,421**	**5,552**	**131**	**2.4%**	**0.27%**

Load growth in the southeastern corner of New Brunswick, though not specifically identified in the load projections, has outpaced the rest of the assessment area.

Demand-Side Management

Current and projected Energy Efficiency effects are incorporated directly into the load forecast, while Demand Response is counted as a load modifier. Moreover, Demand Response is not used for peak shaving. It is used to reduce demand during

[199] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

emergencies and is not backed by capacity reserves. Contractually interruptible (curtailable) Demand Response is projected to account for 252 MW in 2013, increasing to 267 MW in 2022 (NPCC-Maritimes-Table 3).

NPCC-Maritimes-Table 3: Demand-Side Management

NPCC-Maritimes-Winter	Short-Term 2013/14	2014/15	2015/16	2022/23	10-Year Change	2022/23 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	252	254	254	267	15	7.60%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	252	254	254	267	15	7.60%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**252**	**254**	**254**	**267**	**15**	**7.60%**

Jurisdictions within the Maritimes Area have established Energy Efficiency corporations or government agencies whose mandate is to provide sustainable Energy Efficiency and conservation solutions to customers. Policy drivers include maintaining affordable electricity prices for customers and lessening the impact of energy use on the environment. Additionally, a pilot program called PowerShift Atlantic is developing the capability to utilize load control for Ancillary Services. Launched in 2010 as part of the Clean Energy Fund, PowerShift Atlantic is a collaborative research project led in partnership by New Brunswick Power, Saint John Energy, Maritime Electric, Nova Scotia Power, New Brunswick System Operator, the University of New Brunswick, Natural Resources Canada, the Government of New Brunswick and the Government of Prince Edward Island. This four-year, innovative program will run until 2014, piloting technology that shifts energy supply to specific appliances in homes and commercial buildings in order to optimize wind generation with minimal or no disruption to participating electric utility customers.

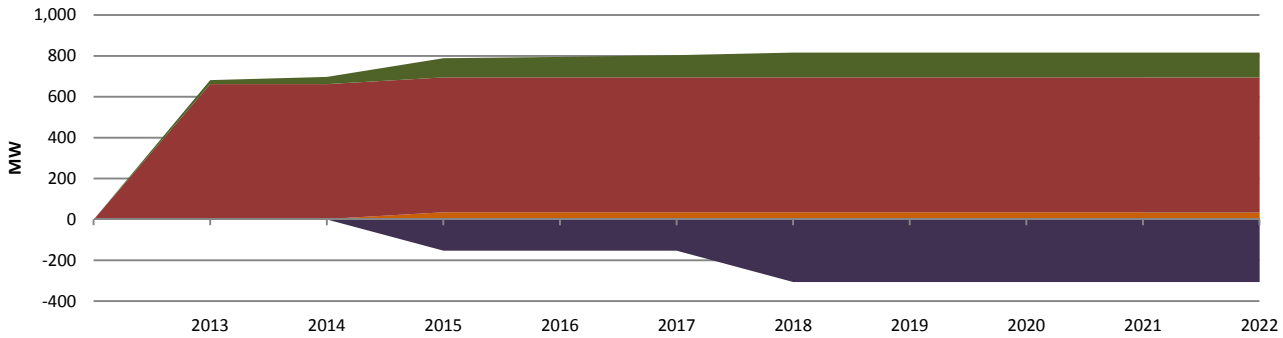
Generation

The primary sources of fuel in the Maritimes Assessment Area are oil and coal, followed by hydro, natural gas, and nuclear. Other capacity sources include wind and biomass (NPCC-Maritimes-Table 4 and NPCC-Maritimes-Figure 2).

NPCC-Maritimes-Table 4: Capacity Outlook[200]

NPCC-Maritimes-Winter	Current Capacity	Current Share	2022/23 Planned Capacity	2022/23 Planned Share	2022/23 Planned Change	2022/23 Planned & Conceptual Capacity	2022/23 Planned & Conceptual Share	2022/23 Planned & Conceptual Change
Coal	1,714	25.0%	1,408	21.0%	-306	1,408	21.0%	-306
Petroleum	1,857	27.1%	1,892	28.2%	35	1,892	28.2%	35
Gas	829	12.1%	829	12.4%	0	829	12.4%	0
Nuclear	660	9.6%	660	9.8%	0	660	9.8%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	1,796	26.2%	1,917	28.6%	121	1,917	28.6%	121
TOTAL	**6,856**	**100.0%**	**6,706**	**100.0%**	**-149**	**6,706**	**100.0%**	**-149**

NPCC-Maritimes-Table 4: Winter Net Capacity Change[201]



[200] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[201] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Since 2011, 49 MW of Existing-Certain capacity fueled by existing natural gas units in combined-cycle mode was added at Nova Scotia's Tufts Cove plant. Another 40 MW of wind generation capacity derated to 14 MW of Existing-Certain capacity was installed at two sites.

The return to service of the 660 MW Point Lepreau Nuclear Generating Station was a major Future-Planned capacity addition during 2012. There are no Conceptual projects planned during this assessment period. The retirement of the 299 MW oil-fired Dalhousie Plant in New Brunswick is scheduled for May 31, 2012. This retirement justifies the addition of a 345 kV breaker at the Belledune 345 kV terminal and reconfiguration of the Eel River 230 kV terminal. From a resource adequacy perspective, the reliability impact of this capacity reduction is more than offset by the return to service of the 660 MW Point Lepreau Nuclear Generating Station, expected to occur by October 1, 2012.

The refurbishment of the Point Lepreau Nuclear Generating Station will result in a 25 MW uprate of the plant's net capacity. This small uprate has no significant long-term reliability impact.

The return to service of the 660 MW Point Lepreau plant will more than offset the capacity loss associated with the retirement of the Dalhousie Plant. The impact of the retirement of Nova Scotia's Lingan generators in 2015 and 2018 is expected to be offset by installation of wind and biomass units and an expected purchase from Nalcor, a Newfoundland and Labrador utility.

There are no significant increases in distributed generation identified in the Maritimes Area except in Nova Scotia. Existing distributed resources are netted against load and not counted as capacity.

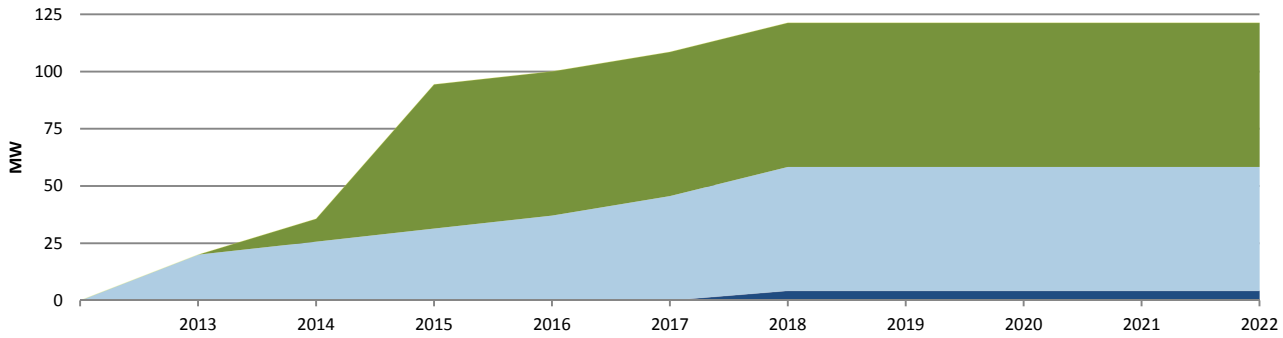
The Maritimes Assessment Area has no non-traditional (e.g., storage, flywheels, batteries) resources. Wind projects included with capacities modeled in resource adequacy calculations for New Brunswick and northern Maine (40 percent of nominal capacity during the winter peak period) are based on results from the September 2005 NBSO report "Maritimes Wind Integration Study."[202] This report showed that the effective capacity from wind projects and their contribution to Loss of Load Expectation (LOLE) was equal to or better than their seasonal capacity factors. The NPCC Maritimes Area "2010 Comprehensive Review of Resource Adequacy"[203] indicated that the area can achieve less than the target maximum of 0.1 days per year of LOLE, even with zero wind installed, while still exceeding its 20 percent NERC Reference Reserve Margin. Renewable capacity for the Maritimes Assessment Area is shown below (NPCC-Maritimes-Table 5 and NPCC-Maritimes-Figure 2)

[202] http://www.nbso.ca/Public/_private/2005 Percent20Maritime Percent20Wind Percent20Integration Percent20Study Percent20_Final_.pdf.
[203] https://www.npcc.org/Library/Resource Percent20Adequacy/Forms/Public Percent20List.aspx.

NPCC-Maritimes-Table 5: Renewable Capacity Outlook[204]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-Maritimes-Winter	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	1,337	74.4%	1,341	69.9%	4	1,341	69.9%	4
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	318	17.7%	372	19.4%	54	372	19.4%	54
Biomass	141	7.9%	204	10.7%	63	204	10.7%	63
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**1,796**	**100.0%**	**1,917**	**100.0%**	**121**	**1,917**	**100.0%**	**121**

NPCC-Maritimes-Figure 2: Winter Net Renewable Capacity Change[205]



The Maritimes Assessment Area projects no solar power installations. With very few small exceptions, hydro and biomass generators are not derated during peak periods.

Currently, wind generators are accredited with on-peak capacity, based on observed or expected seasonally adjusted capacity factors. Hydro and biomass units are expected to be fully available during peak periods, and on-peak capacity is equal to their demonstrated unit capability (NPCC-Maritimes-Table 6). The Maritimes Area is currently reviewing and assessing previously used methods for attributing on-peak wind capacity.

NPCC-Maritimes-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022/23 Planned			
NPCC-Maritimes-Winter	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	816	0	1,339	148	964	0	1,343	211
On-Peak Derate	498	0	2	7	592	0	2	7
EXPECTED ON-PEAK OUTPUT	318	0	1,337	141	372	0	1,341	204

Plans are underway for the individual jurisdictions within the Maritimes Assessment Area to coordinate the sharing of wind data and possibly wind forecasting information and services. With the integration of more variable resources, it may become necessary to curtail these generation levels at light load periods to ensure adequate levels of spinning reserves and inertia for frequency control. The grid codes in the area require the ability to curtail to be designed into the control systems for large-scale variable resources and available for system operators to dispatch accordingly.

Capacity Transactions

The Maritimes Assessment Area has included Firm imports, which are projected to begin in 2018, from the Newfoundland utility Nalcor (NPCC-Maritimes-Table 7). In 2018, development of the Muskrat Falls Generation Project in the Canadian province of Newfoundland and Labrador includes the installation of a High Voltage Direct Current (HVdc) undersea cable link (Maritime Link).

[204] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[205] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

NPCC-Maritimes-Table 7: Projected Capacity Transactions

NPCC-Maritimes-Winter	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	0	0	0	0	0	155	155	155	155	155
Firm Imports	0	0	0	0	0	0	0	0	0	0
TOTAL IMPORTS	0	0	0	0	0	155	155	155	155	155
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**0**	**0**	**0**	**0**	**0**	**155**	**155**	**155**	**155**	**155**

The Expected Firm Import will commence in 2018 and extends well beyond the assessment period. The Maritimes Assessment Area does not depend on emergency imports from other areas to meet the NERC Reserve Margin Reference Level.

Transmission

Three major new transmission line additions are in Conceptual stages during the review period. In New Brunswick, a new 345kV circuit between the Coleson Cove and Salisbury terminals is being considered to improve transmission service to southeastern New Brunswick, which has experienced relatively higher load growth compared to the remainder of the province. New Brunswick and Nova Scotia are studying a project to twin the existing 100-mile-long 345 kV transmission line between Salisbury, New Brunswick, and Onslow, Nova Scotia. This project is under study for 2016 and will allow for increased integration of renewable energy in the Maritimes Area. In 2018, potential development of the Muskrat Falls Generation Project in the Canadian province of Newfoundland and Labrador would see the installation of a High Voltage Direct Current (HVdc) undersea cable link (Maritime Link) between that province and Nova Scotia. Existing and projected transmission additions are listed in the table below (NPCC-Maritimes-Table 8).

NPCC-Maritimes-Table 8: Existing and Projected Transmission

NPCC-New England	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	7,890	216	8,106
Currently Under Construction	182	0	182
Planned - Completed within First Five Years	458	0	458
Planned - Completed within Second Five Years	8	0	8
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	8,537	216	8,753
Conceptual - Completed within First Five Years	78	140	218
Conceptual - Completed within Second Five Years	18	0	18
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**8,633**	**356**	**8,989**

Conceptual 345 kV line reinforcements from Coleson Cove to Onslow would alleviate existing constraints that limit capacity transfers between New Brunswick and Nova Scotia to non-Firm or short-term transactions.

The 2012 retirement of the Dalhousie Plant in NB requires the addition of a new 345 kV breaker at the New Brunswick Belledune terminal to improve local reliability. The plant retirement also made it necessary for the 240 kV terminal at Eel River NB to be reconfigured to allow a single feed to two 240/138 kV parallel transformers to be split. A refurbishment of one of two HVdc stations between the Maritimes Area and Hydro Québec at Eel River New Brunswick is being tentatively planned for 2014. A new 37.5 Mvar capacitor is being constructed at the Norton terminal in southern New Brunswick. This will help maintain voltages in the area during contingency conditions. No new circuit miles are involved in any of these projects. The construction periods for the planned projects mentioned above are all of short duration and can be scheduled during times that will not significantly affect the reliability of the area.

Currently projected for the 2016 time frame, further study to determine need and timing will be completed prior to construction of the Coleson Cove to Salisbury to Onslow 345 kV circuits. The Maritime Link Project and the retirement of a comparable-sized unit will be timed to coincide so that the project will not have an impact on overall reliability.

Being of small size and spread over a multitude of sites, additions to the generation complement in the Maritimes Area of small wind farms and biomass-fueled projects will not require major transmission reinforcement.

A new 37.5 Mvar capacitor is being constructed at the Norton terminal in southern New Brunswick, and a second 36 Mvar capacity bank will be added at Bridgewater in southwest Nova Scotia in 2013. From 2013 to 2022, changes to the HVdc

system in the Maritimes will include the proposed 2014 refurbishment of the 350 MVA Eel River HVdc Station on the New Brunswick tie to Québec and the proposed 2018 addition of an HVdc tie between Nova Scotia and the province of Newfoundland and Labrador (Maritime Link).

Vulnerability Assessment

Because of the relative size of the Maritimes Area's largest generating units compared to its aggregated load, the area carries substantial reserve capacity. Generators use a diverse mix of fuel types with the result that the Maritimes Area is not overly reliant on any particular fuel to meet its load. The area is strongly interconnected with neighboring areas via high capacity transmission lines but is not dependant on these areas to supply area load. As a result, LOLE analysis suggests that even with reasonable foreseeable contingencies including load forecast uncertainty, fuel disruptions, and generator and transmission interruptions, the Maritimes Area load will be reliably supplied for the 10 years covered in this report.

The approximately 1,330 MW hydro-electric power supply system in the Maritimes Area is predominantly run off the river as opposed to storage-based and is not able to be held in reserve to stave off drought conditions. If such conditions were to exist in the Maritimes Area, operation of the system would be relatively unchanged. The hydro system would still be used to follow load in the area and respond to sudden short-term capacity requirements. Thermal units would be used to keep the small storage capability of the hydro systems usable for load following and peak supply.

Because of the relative size of the area's largest generating units compared to its aggregated load, the area carries substantial reserve capacity. Long-term outages to individual units do not cause undue stress from a technical perspective. Because the area peaks in winter as opposed to neighboring jurisdictions that peak in summer, it is expected that any capacity or energy shortfalls due to long-term unit outages could be offset by purchases from New England during their off-peak season, or Québec.

Renewable Portfolio Standards (RPSs) have lead to the development of substantially more wind generation capacity than any other renewable generation type. Reduced frequency response is associated with wind generation and may, with increasing levels in the future, require displacement with conventional generation during light load periods. If required by system operators, wind farms in the Maritimes Area must provide controls that will enable curtailment. In New Brunswick, while increasing RPS requirements to 40 percent of New Brunswick energy by 2020, the government has recently announced that there is enough large-scale wind capacity on the system and that it will shift the focus of the standard to concentrate on less-intermittent hydro (including sources outside the Maritimes Area), wood-based biomass, and small-scale wind developments, but new projects have been identified to date. In Nova Scotia, wind generation capacity is expected to increase with the addition of a government-mandated Community Feed-in Tariff. The Renewable Electricity Standard target is 40 percent by 2020 and is expected to be achieved largely with hydro energy imports through the Maritimes Link Project. Nova Scotia Power has commissioned a renewables integration study with General Electric, the results of which should provide insight into the resource adequacy and operational issues related to increased renewables.

Demand Response in the Maritimes Area consists primarily of interruptible customer load equivalent to 5 percent of peak load for the 2012/2013 winter season. Performance of these customers is metered in real time to ensure compliance with operator instructions. In addition to interruptible load, Nova Scotia implements a 5 percent voltage reduction at selected substations and reduces their demand by approximately 1 MW to 5 MW.

There are no significant increases in distributed generation identified in the Maritimes Area except in Nova Scotia. Existing distributed resources are netted against load and not counted as capacity. In Nova Scotia, increased amounts of renewable generation will be connected to the distribution system through the Community Feed-in-Tariff as outlined in the Province's Renewable Electricity Plan in April 2010. Further study is required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure.

In the New Brunswick sub-area, the government has acknowledged the need to develop less-intermittent sources of renewable energy. With the significant amount of large-scale wind energy currently being balanced on their system, the

next phase of renewable energy development will focus on smaller-scale projects with a particular emphasis on non-intermittent forms of generation, such as wood-based biomass. Wind energy will continue to be integrated in the New Brunswick balancing area, but in measured and manageable stages.

At this time, there are no plans to install more Under-Voltage Load Shedding (UVLS) in the Maritimes Area.

Collectively, UVLS in New Brunswick can shed up to 25 percent of load. UFLS in the Maritimes Area will conform to NPCC Directory 12 requirements calling for 30 percent of area load available to be shed by 2012.

Neither UVLS nor UFLS are used in resource adequacy analysis in the Maritimes Assessment Area. Additional SPS schemes could be implemented in addition to proposed bulk power transmission facilities. At this time, no specific applications are planned for the Maritimes Area during the assessment period.

Scenarios of high load growth, significant resource outages, and zero wind availability (loss of source) are studied for NPCC Comprehensive Reviews of Resource Adequacy. The Comprehensive Area Transmission Reviews require that system performance be studied under stressful conditions such as N-1-1 conditions, extreme contingencies (complete loss of entire generating stations, HVdc ties, etc.), and extreme conditions (weather or loss of fuel) to test the "strength" of the system.

Regional cooperation to mitigate the effects of increases in variable generation has led to a regional research initiative known as PowerShift Atlantic. This initiative will attempt to ease variable generation balancing issues using smart grid technology. Automatic direct control of individual loads will offset changing output from variable resources.

All relay protection misoperations are investigated, and if the relay is found to be faulty, it is replaced. If the settings are found to be in error, they are corrected. If human error was the cause (accidental trips, etc.), the staff involved is trained to avoid the problem in the future. If the relay is misapplied, a new relay scheme is installed to the correct the problem. All of these approaches are taken to reduce the potential for future misoperation.

Renewable Portfolio Standards have mandated increased levels of variable generation in the area, and these have been included in resource adequacy reviews. Within the Nova Scotia sub-area, increasingly stringent air-emissions hard caps have been accounted for in the assessment.

To reduce emissions associated with energy production, governments in the Maritimes Area have introduced Renewable Portfolio Standards, leading to a large-scale development of wind energy resources in the area. The Maritimes Area examines cases in which a complete absence of wind in the area occurs due to weather conditions. The conclusion is that the area is not overly reliant on wind generation to meet its 20 percent reserve criterion (the level at which it has been shown that the area meets the NPCC resource adequacy reliability criterion). Current emissions limits in the Maritimes Area are specified as annual system volumes rather than generator-specific volumes, providing flexibility in the operation of the fleet. Future regulations limiting greenhouse gas emissions are expected and could limit the future utilization of fossil-fueled generation. System Operators in the Maritimes Area are tracking such developing standards and are conducting analyses regarding their impact on future resource adequacy.

No resource deficiencies are forecast and there is no over-reliance on wind to meet area Reserve Margin targets. To avoid an over-abundance of variable generation in the province, the Government of New Brunswick is now concentrating on development of non-intermittent renewable resources. Nova Scotia Power has augmented the supply of renewables with dispatchable biomass. Additionally, the Nova Scotia government has added provisions to the proposed 2020 RES targets that would allow imported renewable hydro energy from the Newfoundland and Labrador utility Nalcor. Nova Scotia Power has commissioned a renewables integration study with General Electric, and the results of the study should provide insight into the resource adequacy and operational issues related to increased renewables.

The 660 MW Point Lepreau nuclear generator is the single largest unit in the area, and upon its return in October 2012, it will have been out of service for four and a half years. During that period, the area met its reserve requirements in part by contracting winter replacement capacity from neighboring areas. During off-peak periods, capacity contracts were

unnecessary. Sufficient capacity exists for the Maritimes Area to meet its target Reserve Margin, should the return to service of Point Lepreau be further delayed. Therefore, long-term maintenance outages in the Maritimes Area are not expected to cause any reliability issues during the assessment period.

With the completion of the Point Lepreau refurbishment in 2012, no other major retrofits are currently scheduled in the Maritimes Area during the assessment period.

Standing and Emerging Reliability Issues

Currently, there are two emerging reliability issues being examined in the Maritimes Area: increasing load in southeastern New Brunswick and additional renewable resources throughout the area.

Increasing Southeastern New Brunswick Load

The issue may require transmission reinforcements within the midterm time frame, which is between four and eight years.

Load growth in the southeastern area of New Brunswick has been more rapid than other areas in the province. Voltages and thermal loading on lines are approaching unacceptable levels during 345 kV contingencies for various operating scenarios.

The effect on resource adequacy is minimal. Generation is unaffected, and the higher loads are included in forecasts used for resource adequacy studies. The impact on LOLE is captured by modeling a reduction in tie transfer capabilities between sub-areas. The 2011 NPCC Interim Review of Resource Adequacy showed that LOLE values do not exceed the NPCC limit of 0.1 days per year of resource adequacy.

The issue could affect BPS reliability by threatening voltage instability and potentially overloading circuits during contingencies in the Assessment Area.

The low voltages and overloads of parallel circuits during contingencies would be moderate but localized and not likely to create problems in neighboring Regions. To address this issue, construction of a new 103-mile-long 345 kV transmission line twinning existing circuits between the Coleson Cove NB and Salisbury NB terminals is being considered. The new line would increase the transmission capacity in the area, alleviating contingency-related overloads and improving area voltages.

The 2012LTRA reference case will not be affected by this issue, and although the load growth and potential voltage issues are localized to southeastern New Brunswick for 345kV outages feeding that area, the circuit overloads occur on parallel 138 kV circuits leading from sources in southwestern New Brunswick to the high load areas in the southeast.

The interconnection of new resources in the area is not considered an issue and would likely help mitigate this emerging issue, as a lack of generating resources situated in this area contributes to the problem. Ultimately, the issue seems to become problematic for 345 KV contingencies when New Brunswick loads are at near-peak levels and there are high southern or northern New Brunswick generation dispatches during periods of high exports from New Brunswick to Prince Edward Island or Nova Scotia.

Addition of Renewable Resources in the Area

Addition of renewable resources, particularly in Nova Scotia, is classified as an emerging issue that may require bulk power enhancements within the midterm time frame of four and eight years. Nova Scotia's Renewable Electricity Standard (RES) seeks to displace significant amounts of fossil-fueled generation with renewable resources. By 2015, 25 percent of the province's electricity sales will be supplied by renewable energy sources, and by 2020 the target is 40 percent. The issue actually enhances resource adequacy, provided existing traditional resources are not prematurely retired as a result of the new capacity.

The addition of renewable resources could affect BPS reliability if increasing amounts of variable or low-mass slow-speed units are added without considering the reduction of frequency response during certain system contingencies or without

sufficient transmission enhancements to prevent voltage or thermal performance issues. The emergence of any of these issues could limit operation of, or the amount of, new renewable generation added to the system.

The issue has not currently affected transmission adequacy, but depending on the location and amount of generation added, it could in the future, since "surplus" transmission capacity is used up to interconnect the new facilities or, on the contrary, congestion is relieved. The process of completing System Impact Studies prior to interconnecting new generation should identify whether transmission adequacy is an issue on a case-by-case basis. The lack of transmission enhancement could delay the development of new renewable resources.

The LTRA case is affected by this issue as Reserve Margins increase due to increasing capacity versus load. Although much of the new renewable capacity is derated to "expected" on-peak values, the actual capacity contribution will be verified through experience with actual operation and further study. In addition, many of the new resources being considered have short timelines, which makes long-term projections less reliable as project plans are introduced, cancelled, or modified in response to changing government incentive policies.

Many of the sites chosen for new renewable generation facilities are located near the energy sources or are sited near existing transmission infrastructure. There is potential for such additions across the entire Maritimes Area.

The variable intermittent nature and low inertia of some renewable resources (in particular wind, by far the most prevalent type) combined with a possible lack of transmission resources in the area of a project site may limit development of these resources.

The intermittent nature of many renewable resources is a major consideration for generation dispatchers on a daily basis. The low inertia effects on system frequency response will be felt mostly during off-peak, light-load periods when high-mass units have been displaced by low-mass, new renewable resources.

NPCC-New England

Planning Reserve Margins

ISO New England expects to have adequate Planning Reserve Margins throughout the assessment period (2013–2022). The amount of Anticipated and Prospective Resources in the 2013 summer is 35,265 MW, which results in an Anticipated Reserve Margin of 32.4 percent of the reference demand forecast of 26,629 MW during the summer season.

Planning Reserve Margin considerations for this assessment newly reflect Seasonal Claimed Capability (which could be higher than the Capacity Supply Obligation (CSO)) of all ISO-NE generators, as well as demand resources and imports that have assumed CSOs under the ISO-NE's Forward Capacity Market (FCM). Consideration for generator Seasonal Claimed Capabilities has not been included in determining the capacity projections in long-term assessments since 2008, when ISO-NE started to use CSOs in the LTRA to reflect the capacity purchased under the FCM. Prior to the 2008 assessment, all generator capabilities in the LTRA were based on the Seasonal Claimed Capability. The reason for reflecting the generator Seasonal Claimed Capabilities in this and future LTRAs is that when the energy prices are lucrative (which is always the case during annual peak demand conditions), generating resources offer the energy market up to, and sometimes more than, their Seasonal Claimed Capability. The LTRA would undercount New England capacity if ISO-NE only reflected the CSOs in the LTRA.

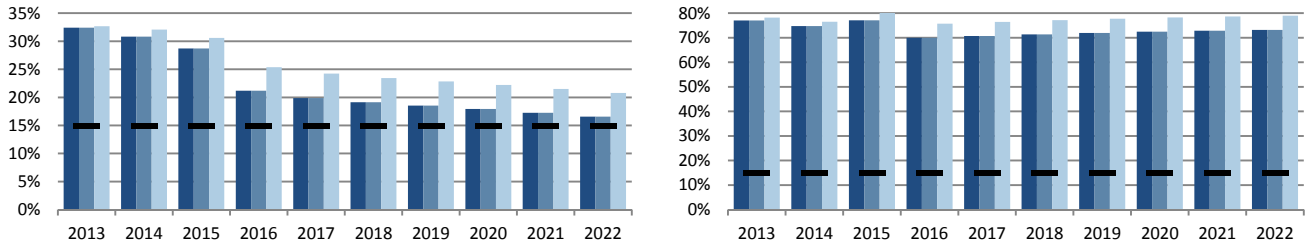
This Reserve Margin during the annual peak reflects the Seasonal Claimed Capability of all ISO-NE generators, as well as demand resources and imports that have Capacity Supply Obligations (CSOs) as a result of ISO-NE's Forward Capacity Market (FCM) auctions. The Adjusted Potential Capacity Resources are slightly higher at 35,329 MW, resulting in a Reserve Margin of 32.67 percent. The Reserve Margins decrease steadily through the assessment period. By 2022, the Anticipated and Prospective Reserve Margins reach a low of 16.56 percent and the Adjusted Potential Reserve Margin decreases to 20.79 percent (NPCC-New England-Table 1 and NPCC-New England-Figure 1).

NPCC-New England-Table 1: Planning Reserve Margins – NPCC-New England

NPCC-New England-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		32.43%	30.82%	28.70%	21.18%	19.88%	19.13%	18.54%	17.93%	17.26%	16.56%
PROSPECTIVE		32.43%	30.82%	28.70%	21.18%	19.88%	19.13%	18.54%	17.93%	17.26%	16.56%
ADJUSTED POTENTIAL		32.67%	32.07%	30.59%	25.39%	24.23%	23.44%	22.84%	22.20%	21.51%	20.79%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

NPCC-New England-Winter		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		77.00%	74.75%	77.09%	70.02%	70.71%	71.38%	71.96%	72.44%	72.83%	73.16%
PROSPECTIVE		77.00%	74.75%	77.09%	70.02%	70.71%	71.38%	71.96%	72.44%	72.83%	73.16%
ADJUSTED POTENTIAL		78.17%	76.51%	80.53%	75.74%	76.46%	77.15%	77.75%	78.25%	78.65%	78.99%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

NPCC-New England-Figure 1: Summer (Left) and Winter[206] (Right) Planning Reserve Margins



New England did not provide a specific Planning Reserve Margin target level and as a thermal system—a NERC Reference Margin Level of 15 percent is applied. ISO New England projects its capacity needs to meet the NPCC once-in-10-year Loss

[206] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

of Load Expectation (LOLE) resource planning reliability criterion. The amount of capacity needs can and do vary from year to year depending on expected system conditions.

There is a potential for lower-than-anticipated reserve margins if significant retirements due to environmental regulations result in lost capacity that cannot be replaced quickly enough by new resources.

Demand

The 2013 summer peak demand forecast is 27,765 MW, and the Net Internal Demand, which takes into account 1,136 MW of passive demand resources (Energy Efficiency), is 26,629 MW.

This year's forecast of the 10-year summer Total Internal Demand compound annual growth rate (CAGR) based on Total Internal Demand is 1.44 percent, which is slightly higher than the 2011 projection of 1.30 percent. The reason for this increase is changes in the economic forecast.

The forecast 10-year winter Total Internal Demand CAGR is 0.57 percent, which is approximately the same as last year's growth rate (NPCC-New England-Table 2). The winter peak is less weather-sensitive than the summer peak; is closely linked to residential demand and is less impacted by the recession.[207]

NPCC-New England-Table 2: Demand Outlook

NPCC-New England-Summer	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	26,629	28,583	1,954	7.3%	0.79%
Load-Modifying Demand Response	1,136	3,000	1,864	164.1%	11.39%
TOTAL INTERNAL DEMAND	**27,765**	**31,583**	**3,818**	**13.8%**	**1.44%**

NPCC-New England-Winter	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	21,383	20,711	-672	-3.1%	-0.35%
Load-Modifying Demand Response	1,127	2,975	1,848	164.0%	11.39%
TOTAL INTERNAL DEMAND	**22,510**	**23,686**	**1,176**	**5.2%**	**0.57%**

This year's forecast of the 10-year net annual energy CAGR is 0.98 percent, which is the same as last year's forecast.

Demand-Side Management

DSM in ISO-NE's BPS consists of active demand resources and passive demand resources. Active demand resources consist of real-time Demand Response and real-time emergency generation, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP-4).[208] Some assets in the real-time Demand Response programs are under direct load control by the load response providers (LRP). The LRP implements direct load control of these assets upon dispatch instructions from ISO-NE—for example, interruption of central air conditioning systems in residential and commercial facilities. Passive demand resources (i.e., Energy Efficiency and conservation) include installed measures (e.g., products, equipment, systems, services, practices, and strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours.

The amount of summer active Demand Resources[209] in 2013 is projected to be 1,681 MW and the amount of passive Demand Resources[210] is 1,136 MW. In the winter, the amount of active and passive DR is 1,536 MW and 1,127 MW, respectively (NPCC-New England-Table 3).

[207] The winter peak is also somewhat dependent on electric heating demand, while the summer peak is directly dependent on air conditioning demand. A much larger number of homes in New England have air conditioning versus electric heat.

[208] OP-4 (located at http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html) is used by ISO-NE operators when resources are insufficient to meet the anticipated load plus Operating Reserve Requirement.

[209] Active Demand Resources in New England are considered Demand Response that is treated as a resource for this assessment.

[210] Passive Demand Resources in New England are treated as load-modifying Demand Response for this assessment.

NPCC-New England-Table 3: Demand-Side Management

NPCC-New England-Summer	Short-Term 2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	1,681	1,999	1,919	1,919	238	6.08%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	1,681	1,999	1,919	1,919	238	6.08%
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	1,136	1,398	1,647	3,000	1,864	9.50%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,136	1,398	1,647	3,000	1,864	9.50%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**2,817**	**3,397**	**3,566**	**4,919**	**2,102**	**15.57%**

In 2022, the amount of summer active DR is projected to be 1,919 MW and the passive DR is 3,000 MW. In the winter, the projected active and passive amounts are 1,795 MW and 2,975 MW, respectively.

The active DR is based on the Capacity Supply Obligations (CSO) obtained through ISO-NE's Forward Capacity Market (FCM) three years in advance. The CSOs increase from 1,681 MW in 2013 to 1,999 WM in 2014 and then decrease slightly to 1,919 MW in 2015. At that point, since there are no further auction results, the CSOs are assumed to remain the same through the end of the reporting period.

Energy Efficiency is also secured by means of FCM CSOs. However, this year ISO-New England developed a new Energy Efficiency forecasting methodology that takes into account the potential impact of growing Energy Efficiency (EE)/conservation initiatives in the Region to project the amount of EE beyond the years when the FCM CSOs have already been procured. EE has been increasing and is projected to continue growing throughout the study period, but at a continually decreasing rate. The amount of EE in 2013 is 1,136 MW, increasing by 23 percent to 1,398 MW in 2014 and by 18 percent to 1,647 MW in 2015. By 2022, the growth rate of EE is projected to be around 6 percent per year, and about 3,000 MW of EE is expected to be available.

Both passive and active demand resources are treated as capacity in New England's FCM. The active demand resources can be triggered by ISO-NE in real time under OP-4 to help mitigate an actual or Anticipated Capacity Deficiency by reducing the peak demand. For example, on July 22, the 2011 peak demand day, a total of 642 MW of active DR was dispatched and 644 MW responded. On another OP-4 occurrence on the morning of December 19, 2011, active DR reduced the load by 380 MW (out of 504 MW dispatched).

Generation

ISO-NE's Existing Certain capacity in summer 2012 is 31,969 MW. Natural gas-fired generation represents the largest component of ISO New England's total installed capacity, followed oil-fired generation, nuclear generation, and coal.

A total of 196 MW of new generation has been installed since the 2011 summer. Most of that capacity consists of a 130 MW gas-fired combustion turbine. In addition, a wind facility with a 62 MW summer rating (217 MW nameplate) went commercial. As explained later in this section, the on-peak capacity of intermittent generators such as wind, hydro, and solar units is based on actual generation during the summer or winter reliability hours. Therefore, the capacity as a percentage of nameplate varies from resource to resource.

ISO-NE has a total of 184 MW of capacity in the Future-Planned Category, all of which is expected to be in service by summer 2013 and consists primarily of biomass (84 MW), wind (42 MW, with a nameplate capability of 228 MW), landfill gas (28 MW), and fuel cell (18 MW) projects. Conceptual capacity[211] amounts to a total of 6,037.[212] A 20 percent confidence factor is applied to that value to reflect the percentage of queue projects that have historically gone into commercial

[211] All of the capacity in ISO-NE's generator interconnection queue that is not included in the Future-Planned Category.
[212] Includes all Conceptual additions with in-service dates from summer 2012 to summer 2017. Does not include conceptual retirements.

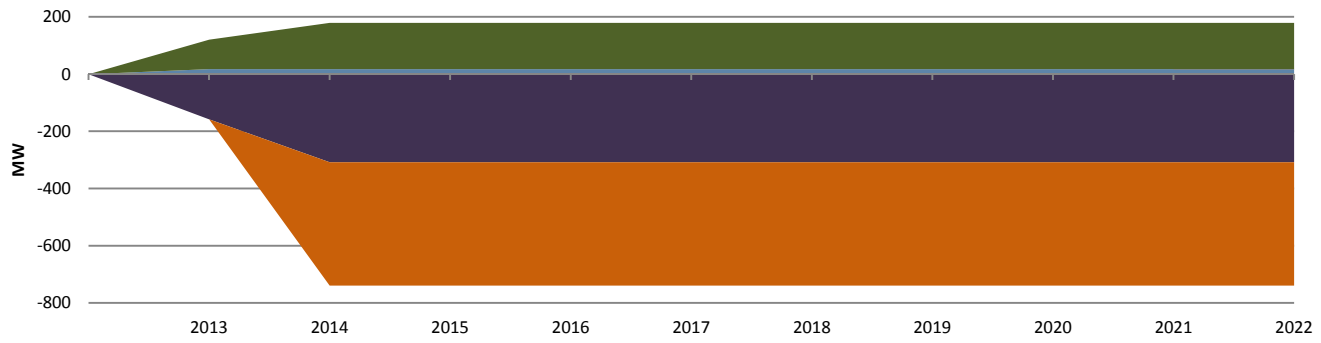
operation. The queue projects include primarily natural gas (3,734 MW), wind (1,991 MW nameplate), and biomass facilities (159 MW). Hydro-electric uprates, oil-fired peaking units, and solar projects make up the remaining 153 MW (NPCC-New England-Table 4 and NPCC-New England Figure 2)

AES Thames, a 181 MW coal plant located in southeastern Connecticut, ceased operation in early 2011. In addition, Salem Harbor units 1 and 2 (158 MW) were shut down as of December 31, 2011, and Salem Harbor Units 3 and 4 (587 MW) are scheduled to retire by June 1, 2014.

NPCC-New England-Table 4: Capacity Outlook[213]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-New England-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	2,484	7.8%	2,176	6.9%	-307	2,176	5.8%	-307
Petroleum	6,895	21.6%	6,463	20.6%	-432	6,505	17.4%	-390
Gas	13,772	43.1%	13,790	43.9%	18	17,525	46.8%	3,753
Nuclear	4,628	14.5%	4,628	14.7%	0	4,628	12.4%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	4,191	13.1%	4,352	13.9%	161	6,613	17.7%	2,422
TOTAL	**31,969**	**100.0%**	**31,410**	**100.0%**	**-560**	**37,447**	**100.0%**	**5,478**

NPCC-New England-Figure 2: Summer Net Renewable Capacity Change



The retirements of both AES Thames and Salem Harbor have been included in the Planning Reserve Margin calculations, and the Reserve Margin remains above the 15 percent Reference Reserve Margin throughout the long-term assessment period. ISO-NE ensures that it has adequate capacity up to three years in advance with its Forward Capacity Auctions and Annual Reconfiguration Auctions. With respect to local loads, there is adequate capacity and transmission within the Connecticut sub-area where AES Thames is located. Since the Salem Harbor plant is located in the Boston sub-area, ISO-NE performed a reliability review to determine the impact of the retirement of the full plant. It was found that under certain second contingency scenarios with a 345 kV line-out as the initial outage, thermal overloads could exist in the local area. To address these thermal overloads, ISO-NE and the affected Transmission Owners have developed plans to perform 115 kV transmission line reconductoring projects on portions of five lines prior to the plant retirement. These upgrades are expected to be completed in May 2014.

ISO-NE has small amounts (less than 5 MW total) of non-traditional resources providing regulation service through a pilot program. These include battery storage, flywheels, electric thermal storage heating, and aggregated load control. After the pilot program concludes, these resource types will remain eligible to provide regulation service. There is no current expectation that these resources will or will not participate in the energy and capacity markets in the future. However, technologies with multi-hour storage capability may become economically viable participants in the energy market depending on fuel prices, penetration of renewable resources, and localized transmission congestion.

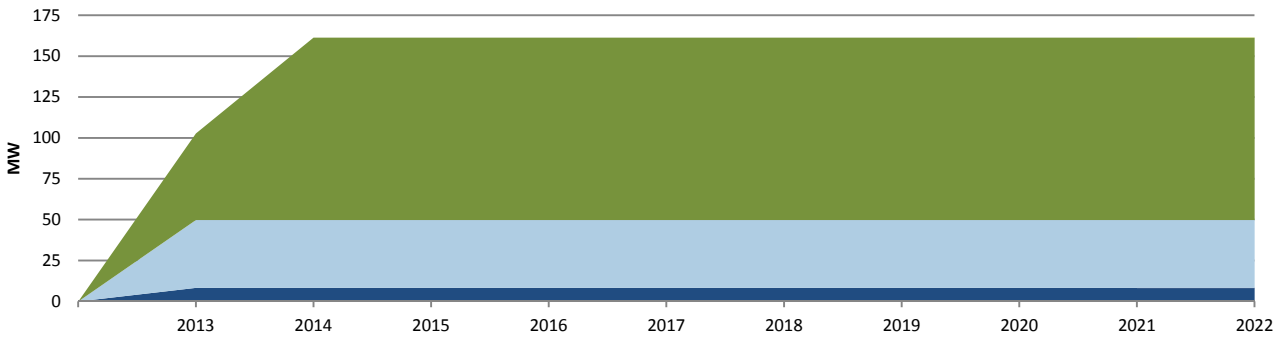
[213] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

As of summer 2012, ISO-NE has 97 MW of on-peak wind capacity, with a total nameplate capability of 566 MW. The amount of on-peak solar capacity is 5 MW, with a nameplate capability of 18 MW. For 2013, on-peak hydro-electric capacity is 1,483 MW, derated from a maximum capacity of 2,043 MW, and biomass capacity is 907 MW (NPCC-New England-Table 5, NPCC-New England-Figure 3, and NPCC-New England-Table 6).

NPCC-New England-Table 5: Renewable Capacity Outlook[214]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-New England-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	1,483	35.4%	1,492	34.3%	8	1,512	22.9%	29
Pumped Storage	1,698	40.5%	1,698	39.0%	0	1,773	26.8%	75
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	97	2.3%	139	3.2%	42	2,129	32.2%	2,032
Biomass	907	21.6%	1,019	23.4%	112	1,177	17.8%	270
Solar	5	0.1%	5	0.1%	0	21	0.3%	16
TOTAL	**4,191**	**100.0%**	**4,352**	**100.0%**	**161**	**6,613**	**100.0%**	**2,422**

NPCC-New England-Figure 3: Summer Net Renewable Capacity Change



NPCC-New England-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
NPCC-New England-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	566	18	2,043	907	794	18	2,051	1,019
On-Peak Derate	469	13	560	0	656	13	560	0
EXPECTED ON-PEAK OUTPUT	97	5	1,483	907	139	5	1,492	1,019

ISO-NE continues to integrate new power supply sources—including new variable resources—into the network. All new resources are studied in detail by ISO-NE Operations Engineering prior to commercial operation. These are all integrated through the use of operating guides/interface limits and through our Energy Management System (EMS). To facilitate system operation with potentially large amounts of wind power, ISO-NE Operating Procedure No. 14[215] was developed and implemented. OP-14F is chiefly concerned with requirements for real-time and static-type data that will facilitate accurate wind power forecasting over the intra-day, day-ahead, and week-ahead timescales, as well as data for use in situational awareness functions for ISO system operators.

Capacity Transactions

Firm summer capacity imports increase from 1,746 MW in 2013 to 1,768 MW in 2015 before eventually falling to 89 MW for the final years of the assessment. The capacity imports for those years reflect the results of the appropriate FCAs. Since the FCA imports are based on one-year contracts, beginning in 2016 the imports reflect only known, long-term ICAP contracts. If the imports beyond the 2015 summer do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or Demand-Side resources (NPCC-New England-Table 7).

[214] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[215] Appendix F – Wind Plant Operators Guide (OP-14F): http://www.iso-ne.com/rules_proceds/operating/isone/op14/.

NPCC-New England-Table 7: Projected Capacity Transactions

NPCC-New England-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	1,746	1,851	1,768	120	95	95	95	95	89	89
TOTAL IMPORTS	1,746	1,851	1,768	120	95	95	95	95	89	89
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	100	100	100	100	100	100	100	100	100	100
TOTAL EXPORTS	100	100	100	100	100	100	100	100	100	100
TOTAL NET CAPACITY TRANSACTIONS	**1,646**	**1,751**	**1,668**	**20**	**-5**	**-5**	**-5**	**-5**	**-11**	**-11**

For the 2012 summer, there is a Firm capacity sale to New York (Long Island) of 100 MW anticipated to be delivered via the Cross-Sound Cable (CSC). This Firm capacity sale is held constant through the assessment period.

Transmission

There are several transmission projects that are projected to come on-line during the assessment period that are important to the continuation of, or enhancement to, system or sub-area reliability. These projects are the results of progress made by the ISO and regional stakeholders in analyzing the transmission system in New England, developing back-stop solutions to address existing and projected transmission system needs, and implementing these solutions. The major projects under development in New England include the Maine Power Reliability Program (MPRP), the New England East-West Solution (NEEWS), and the Long-Term Lower SEMA project. The new paths that are part of MPRP, many components of which are under construction, will provide basic infrastructure necessary to increase the ability to move power into Maine from New Hampshire and improve the ability of the transmission system within Maine to move power into the local load pockets as necessary. NEEWS consists of a series of projects that have been identified to improve system reliability, including in Springfield and Rhode Island, and increases total transfer capability across the New England east-to-west and west-to-east interfaces. The Long-Term Lower SEMA project eliminates the criteria violations in the lower southeastern Massachusetts Area, which includes Cape Cod. Individual 345kV projects, most of which are components of the major projects described above, are listed in the following table, which also includes line upgrades (NPCC-New England-Table 8).

NPCC-New England-Table 8: Planned and Under Construction Transmission Projects

Status	Terminal Origin Location	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Capacity Rating (MW)	Expected In-Service
Under Construction	Larrabee Road S/S	Surowiec S/S	17	300 - 399	2,151	2014
Under Construction	Kent County	West Farnum S/S	21.4	300 - 399	1,353	2013
Under Construction	Manchester	Meekville Jct.	2	300 - 399	2,420	2013
Under Construction	North Bloomfield S/S	Conn/Mass Border	11.9	300 - 399	2,420	2013
Under Construction	Agawam S/S	Ludlow S/S	16.8	300 - 399	2,420	2013
Under Construction	Orrington S/S	Albion Road S/S	59	300 - 399	2,151	2014
Under Construction	Surowiec S/S	Raven Farm S/S	12.4	300 - 399	2,151	2013
Under Construction	Maguire Road S/S	South Gorham S/S	21	300 - 399	2,151	2013
Under Construction	Maguire Road S/S	Three Rivers Switchyard	19.2	300 - 399	2,151	2013
Under Construction	Albion Road S/S	Coopers Mills S/S	21	300 - 399	2,151	2014
Under Construction	Larrabee Road S/S	Coopers Mills S/S	34.3	300 - 399	2,151	2014
Planned	Carver	Bourne	17.9	300 - 399	2,169	2013
Planned	ANP Blackstone	NEA Bellingham Tap	1.2	300 - 399	1,882	2013
Planned	Card S/S	Lake Road S/S	29.3	300 - 399	2,420	2015
Planned	Lake Road S/S	Con/RI Border	7.6	300 - 399	2,420	2015
Planned	West Farnum S/S	Con/RI Border	17.7	300 - 399	2,172	2015
Planned	Millbury S/S	West Farnum S/S	20.7	300 - 399	2,172	2015
Planned	Frost Bridge S/S	North Bloomfield S/S	35.4	300 - 399	2,420	2017

Currently, there are no transmission constraints preventing the system from being operated in a manner that ensures the reliability of the New England-wide system. The proposed projects with the target in-service dates are expected to enhance the long-term reliability of the New England bulk power supply system. There are no major interconnection-related projects or issues at this time. Existing and projected transmission additions are included in the table below (NPCC-New England-Table 9).

NPCC-New England-Table 9: Existing and Projected Transmission

NPCC-New England	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	7,890	216	8,106
Currently Under Construction	182	0	182
Planned - Completed within First Five Years	458	0	458
Planned - Completed within Second Five Years	8	0	8
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	8,537	216	8,753
Conceptual - Completed within First Five Years	78	140	218
Conceptual - Completed within Second Five Years	18	0	18
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**8,633**	**356**	**8,989**

Presently there are no significant concerns over meeting the target in-service dates of any of the transmission projects. However, if the implementation of these projects is delayed, interim measures will be taken, such as issuing gap requests for proposals (RFPs) to install temporary generation in a specific area of the system.

No additional significant substation equipment such as SVC, FACTS controllers, or HVdc is currently planned to be added to the system.

Vulnerability Assessment

The New England Area is currently not experiencing a drought. However, in the event that the assessment area was to experience an extended drought, some traditional hydro-electric stations could be temporarily capacity or energy-constrained. Other fossil stations could also be temporarily capacity limited due to lack of cooling water or other (heat-related) environmental issues.

Due to the relatively small contribution to overall capacity from hydro-electric facilities (1,483 MW, or 4.6 percent), any potential reduction in hydro-electric energy production due to regional drought conditions could be readily supplemented by increased levels of other types of fossil-based generation.

There are no existing or potential significant long-term generator outages that are anticipated to impact reliability during the assessment period.

The New England states' Renewable Portfolio Standards (RPS) include technology classes for new and existing resources, and Load Serving Entities (LSEs) must provide their customers with a specified percentage of electric energy generated by each class each year. Renewables designated as "new" resources (typically Class I RPS resources) are state-specific but typically include wind, solar, hydro-electric, biomass, landfill gas, and ocean thermal. Although the required percentage for new renewable resources varies by state, it increases each year and accounts for most of the growth of RPS targets in New England. The RPS percentage targets for new resources in 2021 for the five New England states with RPSs range from 10 percent for Maine to 20 percent for Connecticut, with New Hampshire, Rhode Island and Massachusetts at 12, 14 and 16 percent, respectively. It is assumed that these targets will be met by generators in the ISO-NE generator interconnection queue, which had 2,577 MW of renewable projects as of April 1, 2012. Wind makes up approximately 85 percent of that potential renewable capacity.

Concerns exist over the resultant impact from compliance with state RPS and the potential build-out of these new renewable resources. Because of concerns over the increasing amount of wind capacity, ISO-NE completed a major wind integration study to identify the detailed operational issues of integrating large amounts of wind resources into the New England power grid. ISO-NE is currently implementing the recommendations of this study, including the development of a centralized wind power forecasting system.

Although the amount of ISO-NE's solar capacity is still small (18 MW nameplate), the number of solar projects has increased significantly in recent years and is likely to continue growing due to incentives that all the New England states have in place. Currently, it is estimated that New England actually has about 125 MW of nameplate solar capacity. However, only about 15 percent of that is registered in ISO-NE's energy and capacity markets, with the rest remaining behind the meter.

The implementation of the FCM has enhanced the integration of demand resources into system operations. ISO New England has two real-time demand resource programs that can be used to manage load and reserves as part of implementation of ISO-NE OP-4. The first program is focused on load response and is utilized in the early stages of OP-4. The second is emergency generation (RTEG), which is accessed in a later action of OP-4. All of these resources are audited annually in both the summer and winter for their ability to perform. Based on DR audits in summer 2011 and the response of active DR during the July 22, 2011 OP-4 event, ISO-NE expects that approximately 95 percent of DR capacity will perform when triggered. In addition, each demand resource submits the hourly status of their capability to the ISO, and the system operators are able to view that capability in real time. Finally, the operators are provided with telemetry from each resource to monitor the real-time performance of the resources in relation to their capacity supply obligations.

Due to the fact that distributed generation (DG) must be integrated into the local electric company's distribution systems, it must comply with the interconnection standards applicable to such systems. This distributed generation is traditionally not a major concern for BPS operation, although relatively large DG projects can be studied by ISO-NE. ISO-NE does not anticipate any operational problems or reliability concerns resulting from the levels of distributed generation enrolled within its Demand Response programs.[216] The FCM qualification process requires additional information for projects that include the use of DG to ensure that they comply with the definition of DG within FCM.

In December 2010, ISO-NE completed the New England Wind Integration Study (NEWIS), a major study of integrating wind resources into the New England electric system. The study found that the large-scale integration of wind resources is feasible, but the Region will need to continue addressing a number of issues. Those issues include the need to: 1) ensure revenues for other types of generation to maintain system reliability; 2) increase system flexibility and improve market design to provide incentives for dispatchable resources; 3) provide increased operating reserve and regulation; 4) evaluate the accuracy of methods for calculating wind capacity; 5) develop transmission to interconnect wind resources and bring the energy to load centers in New England; 6) develop an accurate means of forecasting wind generation output; and 7) update interconnection requirements for wind generation.

The results of NEWIS will serve as the basis for regional policies and practices by ISO-NE, wind project owners, and interconnecting transmission owners, and may result in changes to the ISO-NE tariff, operating procedures, and manuals. ISO-NE will continue to work with stakeholders through the usual stakeholder processes to implement the study's findings, which may require modifying market and reliability rules necessary to facilitate the large-scale integration of future wind resources.

The majority of actions to be implemented in the near term were derived from the NEWIS-identified technical requirements for interconnection.[217] The balance of the integration efforts will be prioritized and completed through ISO-NE's stakeholder process.

The Wind Power Forecast Integration Project (WPFIP) is the first phase in the progression of steps necessary to fully integrate wind power into the ISO-NE system. Currently in New England, variable energy resources (VERs) perform their own forecast of generation for each hour of the next operating day, which they submit to ISO-NE as a self-schedule (forecast) on the day preceding the operating day. Phase 1 of the WPFIP will replace this self-scheduled forecast with a centralized forecasting system, as described above. Phase 2 of the WPFIP will make it possible to dispatch wind plants in a manner similar to that of other ISOs that have integrated wind power into their dispatch process. Integration into real-time dispatch means that wind plants will submit economic offers and be able to set prices at their local bus, and transmission congestion will be managed in a transparent and automated process (versus the typically manual process that is currently

[216] Within New England, the capacity and load relief benefits from triggering distributed generation, Real-Time Emergency Generation (RTEG), is only attainable through the invocation of ISO-NE Operating Procedure No. 4 – *Action during a Capacity Deficiency* (OP-4) – Action 6 of 11.

[217] GE Energy Application and Systems Engineering, et al., *Technical Requirements for Wind Generation Interconnection and Integration* (November 3, 2009), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/newis_report.pdf.

used for real-time self-scheduled resources). Phase 2 of the WPFIP will also include closer coupling with the short-term outage scheduling process and will include publishing of the aggregate week-ahead wind power forecast (similar to the manner in which a week-ahead load forecast is published) in order for the market participants to be able to incorporate this information into their decision-making processes and market strategies.

At this time, there are no plans to install more Under-Voltage Load Shedding (UVLS) in New England. Currently, northern New England has the potential to arm approximately 600 MW of load shedding as part of UVLS. However, it is important to recognize that a significant portion of this load shedding is normally not armed and is only armed under severe loading conditions with a facility already out of service. Presently, two significant projects have the attribute of either completely eliminating the need for the UVLS or significantly reducing the likelihood of depending on such schemes. These projects are the Vermont Southern Loop Project and the Maine Power Reliability Program (MPRP). The Vermont Southern Loop Project was completed in late 2010 and the MPRP project is scheduled to be completed in 2014.

There are no Special Protection Systems that are proposed to be installed in lieu of proposed regulated transmission facilities to address system reliability needs in New England in the assessment time frame. However, two new, temporary Special Protection Systems are to be installed in Maine as part of the MPRP. The first SPS is needed to ensure reliable system operation due to configuration changes at South Gorham while the MPRP is under construction. The second SPS is needed to ensure reliable system operation due to configuration changes in the Rumford Area while the MPRP is under construction. Once construction of the necessary portions of the MPRP is complete (anticipated in 2014), these two temporary Special Protection Systems will be removed.

New smart grid technologies are being used in New England to improve the electric power system's performance and operating flexibility. Smart grid technologies such as flexible alternating-current transmission systems (FACTS) and high-voltage direct current (HVdc) will facilitate the integration of variable resources in the Region and reliably improve the economical operation of the power system. Because much of the potential for wind development is remote from load centers, additional transmission development will be required. Some of these transmission improvements will likely use HVdc technology, which is economical over long distances, and FACTS, which makes better use of limited transmission facilities. Both HVdc and FACTS are regularly considered as part of transmission planning studies when their application economically meets system or generator interconnection needs.

On July 1, 2010, ISO-NE received a U.S. DOE Smart Grid Investment Grant Award and subsequently began a three-year Synchrophasor Installation and Data Utilization (SIDU) project. The goal of the project is to provide ISO-NE and associated Transmission Owners a significantly expanded base of Phasor Measurement Units (PMUs), Phasor Data Concentrators, and greatly enhanced phasor data analytical tools. The SIDU project will supplement the five existing PMUs in the Region with at least 30 new PMUs at various substations around New England. The project is focused on the deployment of synchrophasor technology as a foundation for the next generation of power grid situational awareness, and it will serve as the smart grid technology platform upon which advanced analysis and visualization tools can be deployed. The SIDU project will yield efficiencies in the way the grid is operated and will improve reliability, serving as a backbone for regional smart grid efforts.

In addition, several investor-owned and municipal utilities are conducting smart grid pilot programs or projects in New England ranging from smart meter deployments to full-scale direct load control and distribution automation projects. ISO-NE anticipates that these projects may lead to more significant smart grid assets becoming available for potential utilization during the Long-Term Reliability Assessment period.

New England relies upon the facility owners to investigate relay protection misoperations with cooperation and technical support from ISO-NE. The facility owners will then determine the cause of the misoperation and implement corrective actions for that facility and other facilities that have the same concern. New England has a number of forums that allow the equipment owners to share information they feel may be useful to other equipment owners in preventing similar events.

ISO-NE routinely reviews the existing, pending, and promulgating environmental regulation for their potential impact on existing or future capacity. Under the workloads associated with its Strategic Planning Initiative, ISO-NE has identified several regional power stations that may be retired due to the economics of compliance with pending state and federal air and water regulations.

Emerging environmental regulations will very likely require large capital investments that may be uneconomic for many older fossil-fueled resources. While the exact form and timing of the regulations remain uncertain, it is highly likely that substantial compliance investments will be required by owners of existing New England resources to continue operations. This could lead to a significant quantity of older generation choosing to retire rather than comply.

Approximately 7.9 GW of coal- and oil-fired capacity located in New England is subject to the final Mercury and Air Toxics Standards (MATS). Many coal-fired units have or are planning needed retrofit controls to comply with existing state regulations, and most oil-fired units are expected to utilize a safe harbor exemption to continue operation beyond the April 2015 compliance deadline. Overall, less than 1 GW of affected capacity in New England is expected to retire due to non-compliance with the MATS.

A total of 12.1 GW of thermal station generating capacity using once-through cooling in the Region is subject to the proposed Clean Water Act Section 316(b) cooling water rule and will likely be required to modify existing cooling water intake structures by 2020 to minimize loss of fish and other aquatic life. A smaller subset of this affected capacity with water withdrawals greater than 125 million gallons per day (estimated at 5.6 GW) will likely need to convert to closed-cycle cooling in the same time frame. ISO-NE estimates that between 1 and 3 GW of affected capacity in New England may retire by 2020 due to non-compliance with CWA Section 316(b).

Currently, the procedures that are in place to maintain system reliability include reliability agreements and out-of-merit unit commitment. However, ISO-NE is studying longer-term solutions to the problem, such as appropriate enhancements to wholesale market design and system planning procedures. Losing a significant quantity of coal, oil, and nuclear capacity could further increase the assessment area's dependence on natural gas-fired resources. If all of New England's older oil units were to seek retirement, new capacity would be required to satisfy the Installed Capacity Requirement.

ISO-NE has initiated and is aggressively promoting a regional dialogue focused on solutions that can avert undesirable outcomes. ISO-NE has initiated a study to better quantify the implications of this issue. This analysis will complement the 2010 economic planning studies. For more information, reference the Standing and Emerging Reliability Issues section.

At this time there are no planned outages for generator environmental retrofits that would impact reliability. Many environmental retrofits needed for MATS have already been placed into service or are planned well ahead of the April 2015 compliance deadline. Remaining retrofits are expected to be completed during traditional outage periods.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

ISO-NE has received notification of the retirement of Salem Harbor units 3 & 4, with a combined capability of 587 MW. The retirement is to take effect on June 1, 2014.

Between 2012 and 2021, environmental regulations could require generators to incur significant capital costs for retrofits. The added pollution control equipment could restrict operation and the cost of compliance could render some of these generators non-price competitive, resulting in the retirement of additional generation. The compliance retrofits could include adding post-combustion control devices, modifying cooling water intakes, switching to closed-cycle cooling systems, or switching fuels. ISO-NE estimates that, in total, these regulations would affect over 12.1 GW of installed capacity across New England.

Because new environmental requirements are in flux and are being phased in over the next decade, assessing the potential impacts that the resulting regulations could have on generators and the power system poses some challenges. First, the capital investments some generation owners will need to make are uncertain for complying with the Mercury and Air Toxics

Standards (MATS) of the US EPA Clean Air Act (CAA) and the Cooling Water Intake 316(b) Rule of the Clean Water Act (CWA). Other unknowns include the timing, magnitude, and location of unit retirements that could result from generators opting not to comply with these regulations.

As part of the Strategic Planning Initiative, ISO-NE is collecting and analyzing data to identify the units expected to face significant capital investments because of upcoming regulatory requirements and to assess the potential resulting impacts on transmission system operations. The ISO has also initiated a study to better quantify the implications of the likely retirement of several generating units and their potential replacements. The ISO is identifying generators that already have environmental remediation measures in place or may require relatively minor upgrades and those at risk for retirement. The actual compliance timelines will depend on the timing and substance of the final regulations and site-specific circumstances of the electric generating facilities. Most of the at-risk capacity would face compliance or retirement decisions—and Forward Capacity Market positioning decisions—starting late in this decade, extending into the early part of the next decade.

A total of 12.1 GW of fossil and nuclear capacity are subject to the proposed Cooling Water Intake Rule, which is expected to be finalized in June 2013. This rule directly affects a total of 5.6 GW of fossil-fueled and nuclear facilities with 125 MGD or higher once-through cooling water systems, which likely will be obligated to convert to closed-cycle cooling systems between 2018 and 2024. The ISO estimates that approximately 1 GW to 3 GW of the 5.6 GW subject to the additional requirements of EPA's preferred option[218] may retire between 2018 and 2020, rather than retrofit to closed-cycle cooling systems.

The MATS rule affects coal- and oil-fired steam units over 25 MW. The final MATS rule will have a relatively modest impact on New England generators. Although 7.9 GW will be affected, less than 1 GW of environmental retirements are anticipated by 2015. Most oil-fired generators are expected to continue operating after 2015, and limited additional pollution control retrofits are required for the remaining coal-fired generators, which have mostly completed or are implementing retrofits.

Compliance with environmental requirements will require the coordination of construction schedules and maintenance outages at affected generators to avoid diminishing system reliability. ISO-NE schedules planned outages up to approximately two years in advance. At this time, three outages related to environmental retrofits, totaling approximately 1,100 MW, have been scheduled during the assessment period.

Since the Salem Harbor plant is located in the Boston subarea, ISO-NE performed a reliability review to determine the impact of the retirement of the full plant. It was found that under certain second contingency scenarios with a 345 kV line-out as the initial outage, thermal overloads could exist in the local area. To address these thermal overloads, ISO-NE and the affected Transmission Owners have developed plans to perform 115 kV transmission line reconductoring projects on portions of five lines in the North Shore area prior to the plant retirement. These upgrades are expected to be completed in May 2014.

There are no major interconnection-related projects at this time.

To ensure resource adequacy for the system, the amount of capacity the system requires in a given year is determined through the Installed Capacity Requirement (ICR) calculation, which accounts for uncertainties, contingencies, and resource performance under a wide range of existing and future system conditions. The ICR is the amount of capacity that must be obtained through supply-side and demand-side resources in the Forward Capacity Market. Through the FCM, which consists of a series of auctions and bilateral trading periods, specific resources are procured and committed for meeting the ICR, and

[218] EPA's preferred entrainment-mitigation option requires electric power generating facilities with 125 MGD or higher once-through cooling water systems to prepare and submit an entrainment-characterization study for determining whether they would need to retrofit to closed-cycle cooling systems. These facilities would need to follow an expedited schedule for submitting CWIS performance data to regulators.

other key values are identified. Purchased capacity resources must be available in the specified timeframe to ensure the region has adequate resources.

The FCM's Forward Capacity Auctions are designed to procure capacity roughly three years (40 months) in advance of the commitment period. This lead time allows capacity suppliers to develop new capacity resources and enables the ISO to plan for these new resources.

The results of the most recent Forward Capacity Auction show that New England will have adequate resources through 2015/2016, assuming that resources meet their capacity supply obligations. Most recent increases in capacity have come from both demand resources and imports from neighboring regions, and approximately 6,600 MW of proposed generation are in the ISO Generator Interconnection Queue. The ISO remains optimistic that adequate demand and supply resources will be procured and installed in time to meet the physical capacity needs that will be established by the ICRs for future years.

Because additional retirements may occur, ISO-NE is working with stakeholders to identify issues and find the means of meeting future capacity needs. The ISO is studying the potential retirement of aging units as part of its Strategic Planning Initiative. The capacity mix in New England currently operates with about 6 GW of fossil-fueled generating units (primarily coal or oil) that are older than 40 years. That amount increases to 8.5 GW by 2020. Existing and pending environmental initiatives that require reduced air emissions and controlled water withdrawals and discharges are placing increased economic pressure on aging coal-and oil-fired units to add environmental controls or to reduce run times. Given their age and lack of operating revenues and the new capital investment that may be required, many of these coal and oil units are likely to retire in the latter half of the decade and be replaced with efficient and relatively clean-burning natural-gas-fired units. The ISO is conducting studies to assess the economic and reliability effects of retiring aging, environmentally challenged generating units and their likely replacement with natural-gas-fired generation, variable renewable resources, and imports from the neighboring Canadian regions.

ISO-NE is performing a Strategic Transmission Analysis, which is assessing potential transmission issues associated with generator retirements and examining "broad" transmission system requirements to integrate renewable resources for the 2020 study year. Some portions of the study will be complete in 2012, which include interim reports, and the remainder of the study is scheduled for 2013.

The initial study system conditions include the integration of demand resources and the retirement of oil and coal generating units more than 50 years old. The study also assumes the repowering of existing old coal- and oil-fired generators with natural gas, which would not require a major expansion of the transmission system. Therefore, the Strategic Transmission Analysis focuses on the ability of wind, other supplemental capacity, or a combination of all resources to address the reliability needs resulting from the potential removal of generators, both simultaneously and in smaller clusters.

Standing and Emerging Reliability Issues

Since early 2011, ISO-NE, the New England states and market participants have engaged in a Strategic Planning Initiative (SPI) focused on the future of the wholesale electricity sector in New England. ISO-NE launched the SPI to highlight key risks to the efficient operation of the wholesale electric markets and reliability of the BPS. As part of the SPI, ISO-NE sought feedback from the Region's stakeholders on the nature and urgency of the risks. Following these discussions, a broad consensus was reached regarding the risks facing the Region. ISO-NE has suggested a path forward to both mitigate these risks and lay the groundwork for an electricity system driven by public policy goals, economic factors, and new technologies.

As part of its SPI, ISO-NE has identified five key risks to the efficient operation of the wholesale electric markets and reliability of the BPS.[219] These five risks, which are both standing and emerging, are:

- **Resource Performance and Flexibility** – related to the uncertain performance and/or constrained operational accessibility of demand resources and aging supply resources, and the need to increase system flexibility.
- **Increased Reliance on Natural Gas-Fired Capacity** – related to the reliance on natural-gas-only resources, as sufficient gas may not be available to meet power system needs during periods of very high seasonal demand, under other stressed system conditions, or when facing contingencies associated with natural gas supply/transportation system infrastructure.
- **Retirement of Generators** – related to the economic and policy factors that will result in the potential exit of a substantial portion of existing, older fossil-fuel capacity.
- **Integration of a Greater Level of Variable Resources** – related to the need for a steady increase in system flexibility as more variable resources, primarily renewable energy resources are added to the system over the next several years.
- **Alignment of Markets with Planning** – related to the need to better align— from timing and analytic perspectives— wholesale market procurements with transmission planning processes to allow reliability needs to be met through either market resources or backstop transmission solutions.

The following discussion will relate to the first three issues listed above: 1) Resource Performance and Flexibility, 2) Increased Reliance on Natural Gas-Fired Capacity, and 3) Retirement of Generators. The other two issues are equally important, but ISO-NE determined that the first three issues are the highest priority risks that may impact system reliability in the near term, while the other two issues are longer term in nature.

1: Resource Performance and Flexibility

Recent experience has indicated that the current fleet of resources in New England could be better matched to existing and likely future system operational needs. Current contingencies assumed in operations and planning are large relative to the size of the New England system. In practice, since there are limited readily-available, off-line reserve resources, the commitment of additional resources for on-line reserves is required at times. Moreover, the system has limited flexibility given the current market incentives and unit performance characteristics. The current circumstances include the slow response and decreased reliability of older thermal units; the relatively narrow operational band of more responsive, newer combined-cycle units; the frequent participation in energy markets of capacity that is responsive but energy-limited, rendering it unavailable to serve as reserves or provide ramping functions; and the constrained operational accessibility to certain classes of demand resources that can only be dispatched in emergency conditions.

Although this issue does not directly impact resource adequacy from a supply/demand balance perspective, it leads to conditions that increase the complexity of reliable system operations and will likely decrease the efficiency of the wholesale markets. Reliability will be impacted due to increased commitment and out-of-merit dispatch, the potential rejection of "economic delist bids" due to local reliability concerns, and sanctionable violations of NERC Reliability Criteria. ISO-NE expects that the operational challenges related to unit performance and flexibility will increase in severity and frequency with the retirement of uneconomic generating capacity.

The resulting impact on the transmission system is likely to be negligible. However, the LTRA Reserve Margins may be impacted depending on remedial measures, such as the derating of units to reflect lower availability, which may result in a reduction in capacity. The extent of the potential impact is unknown at this time.

The results of studies regarding this issue and implementation of mitigation measures may impact the specific technology types and operating characteristics of new resource development and procurement.

[219] The risks and the path toward mitigation can be found in more detail on the ISO-NE web site under the Strategic Planning Initiative directory located at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html.

Contingencies that are larger and more frequent than those currently assumed in ISO-NE operations and planning could increase the vulnerability of New England's electric grid. Increased ramping requirements for both the morning and evening load pick-ups (and drop-offs) could also exacerbate this issue.

2: Increased Reliance on Natural Gas-Fired Capacity

On several occasions over the past 10 years, New England has faced challenging operating conditions related to the availability of the Region's gas-fired generating capacity (e.g., 2004 Cold Snap, 2009 Sable Island Outage, January 2011 cold weather, and April/May 2011 liquefied natural gas shortages). These operating conditions were linked to disruptions in natural gas supply or transportation infrastructure, regional and global natural gas market conditions, and natural gas availability for power generation under peak "cold snap" natural gas demand conditions. These natural gas-related operational and economic risks are already in evidence.

As discussed within the next issue, it is expected that the upcoming unit/station retirements will heighten this gas dependence risk. The Region will lose (coal and oil-fired) capacity that currently provides fuel diversity under constrained gas availability conditions, and the residual and replacement capacity may be primarily natural gas-fired, or may be of a resource type that does not provide operational certainty under constrained gas availability conditions.

In support of ISO-NE's SPI concerning natural gas, a high-level, deterministic assessment was performed in 2011 to assess the ability of the regional gas supply and delivery systems to serve seasonal electric power sector demands based on the economic dispatch of all generation. The study assessed the gas supply available for New England's gas-fired power generation through 2020 on peak winter and peak summer days. The analysis considered the gas demands of existing generators as well as a scenario assuming that a portion of the non-gas-fired capacity in the assessment area retires and is replaced with new natural gas-fired capacity.

The 2011 Natural Gas Study[220] concluded that the natural gas pipeline capacity is insufficient during winter for satisfying the economical gas needs for New England's power plants during the next decade.

With existing natural gas-fired capacity in place, the existing natural gas infrastructure is insufficient to meet electric power system demand (for natural gas) for all study years (i.e., the winter of 2011/12 through the winter of 2019/20) for all electric system demand scenarios. In the later years of the study, deficiencies reach approximately 625,000 dekatherms per day (Dth/day) in some years in the reference case, to as much as 1,375,000 Dth/day in the maximum electric demand scenario. A gas deficit of 240,000 Dth/day is estimated to be equivalent to a shortage of 1,000 MW/day, with an assumed full-load heat rate of 10,000 Btu/kWh. No shortages are expected under reference system conditions during the summer peak because gas local distribution company demand in the summer is minimal, opening up substantial capacity on the natural gas system in quantities that generally exceed increased summertime power generation demand.

The study also considered natural gas system contingencies for the same assumptions of natural gas and power system demand. These results and findings are considered Critical Energy Infrastructure Information (CEII).

While the study shows gas-fired electric generators would have shortfalls in fuel supply and thus seasonal unit availability, replacement or supplemental (coal- and oil-fired) capacity may soon not be available to the ISO for mitigation purposes. However, power system reliability can be preserved in a number of ways. Alternate sources of electric energy could be used when gas supply shortage events are projected, including dual-fuel generating units using fuels other than natural gas, and imports from neighboring systems, such as Canada. In addition, the Region is showing growth in Energy Efficiency, and increased renewable sources of energy will likely develop in the Region. Firm contracting for gas supply and transportation may also help in mitigation, but "Firm" is still "not-Firm" under force majeure scenarios.

[220] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public.pdf.

The procurement of non-Firm natural gas supply and transportation within the electric sector may result in the loss of single-fuel gas-fired stations, thus changing the topology of the integrated electric generation and transmission grid. It is unknown at this time whether the end result would be an increase or decrease in existing transmission interface constraints, or the development of new constraints. In addition, the potential unit reductions and unavailability could directly decrease seasonal Reserve Margins over the study period.

As noted earlier, because the Region is so dependent upon natural gas-fired generation, any contingency on the regional gas grid or upstream of New England's gas grid may temporarily impact fuel deliveries into and throughout the Region. These contingencies could be in the form of "force majeure" on regional gas infrastructure or originate as a result of planned or unplanned maintenance.

3: Retirement of Generators

One of the near-term risks is the potential for substantial unit retirements before the planned long-term changes can influence resource development decisions. From a market perspective, the retirement of existing uneconomic capacity is an efficient outcome and was contemplated in the design of Forward Capacity Market (FCM). The concern, then, is not with retirements per se; rather, ISO-NE has identified unit retirements as a strategic risk due to their potential magnitude in a relatively short time frame, and the interaction between unit retirements and existing challenges associated with the performance, flexibility, and high gas dependence of the existing fleet.

The capacity mix in New England—a system with summer peak requirements of roughly 30 gigawatts (GW)—includes over 6 GW of fossil-fueled generating units (primarily coal or oil) that exceed 40 years in age, which run at heat rates exceeding 10,000 Btu/kWh. Oil-fired generation, representing 22 percent of existing capacity in the Region, operates at an average capacity factor of less than 1 percent, but during system peaks provides almost 20 percent of the Region's energy. Under current fuel prices and other market conditions, this group of resources faces economic challenges. These units may effectively need to recover all variable and fixed costs, including any new capital investments, from energy markets whose prices are dictated in many hours by currently low natural gas prices from highly efficient, new generating facilities. In other words, even without new capital investment requirements, a significant portion of the Region's generating fleet is at risk of retirement.

Studies are currently being conducted to assess the resultant reliability impact from both resource adequacy and transmission security perspectives. While the studies are still unfinished due to the ever-changing regulatory environment, the most likely outcomes are shortfalls in summer capacity margins, loss of mitigation measure during winter peak operations, and possible, various impact on transmission as a result of critical unit/station retirements. The studies are targeted for approval and publication by the end of 2012.

The direct result of the unit retirements would be a decrease in seasonal Reserve Margins over the study period, barring a quick influx of replacement capacity. The results of new capacity integration studies and implementation of other mitigation measures to remediate other SPI risk factors may dictate or impact the specific technology types and operating characteristics of new resources.

New capital investment requirements associated with emerging U.S. Environmental Protection Agency (EPA) rules related to mercury/air toxics and cooling water standards could precipitate unit retirements in the latter half of the decade. Any changes to the proposed regulatory compliance dates moving forward may become problematic. As the long-term changes will not be in place in time to influence new resource development, the Region must either consider near-term enhancements to the current structures or allow the existing processes to manage the transition.

NPCC-New York

Planning Reserve Margins

The New York Balancing Authority (NYBA) is projecting adequate Planning Reserve Margins from 2013–2022, based upon the current NYBA Installed Reserve Margin (included in this assessment as the NERC Reference Margin Level) (NPCC-New York-Table 1 and NPCC-New York-Figure 1).

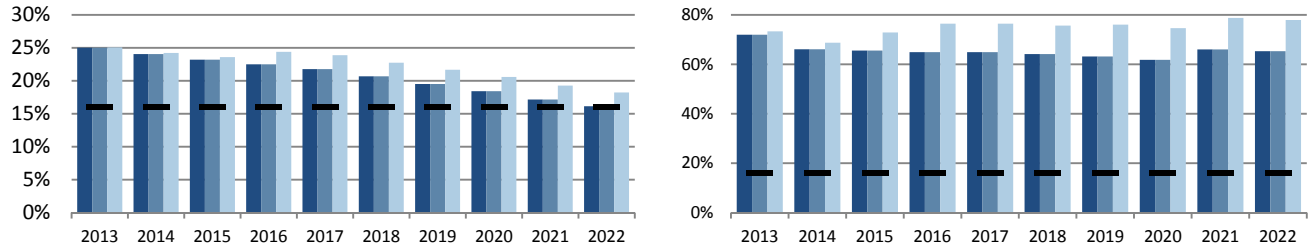
The current Installed Reserve Margin (IRM) requirement for the NYBA Area that covers the period from May 2012 to April 2013 (2012 Capability Year) is 16 percent. This requirement is based upon an annual study conducted by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee (ICS).

NPCC-New York-Table 1: Planning Reserve Margins

NPCC-New York-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		25.02%	24.07%	23.21%	22.51%	21.79%	20.68%	19.52%	18.44%	17.16%	16.14%
PROSPECTIVE		25.02%	24.07%	23.21%	22.51%	21.79%	20.68%	19.52%	18.44%	17.16%	16.14%
ADJUSTED POTENTIAL		25.09%	24.22%	23.59%	24.40%	23.88%	22.75%	21.68%	20.58%	19.28%	18.24%
NERC REFERENCE	-	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**

NPCC-New York-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		72.02%	66.13%	65.57%	64.94%	64.91%	64.18%	63.17%	61.86%	66.06%	65.33%
PROSPECTIVE		72.02%	66.13%	65.57%	64.94%	64.91%	64.18%	63.17%	61.86%	66.06%	65.33%
ADJUSTED POTENTIAL		73.36%	68.78%	72.93%	76.46%	76.44%	75.65%	76.06%	74.65%	78.76%	77.98%
NERC REFERENCE	-	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**

NPCC-New York-Figure 1: Summer (Left) and Winter[221] (Right) Planning Reserve Margins



Demand

The 2011 LTRA forecast compound average growth rate (CAGR) was 0.66 percent from 2012 to 2021, compared to 0.81 percent for this assessment period (2013-2022).

NPCC-New York-Table 2: Demand Outlook

NPCC-New York-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	33,696	36,230	2,534	7.5%	0.81%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**33,696**	**36,230**	**2,534**	**7.5%**	**0.81%**

NPCC-New York-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	24,929	25,908	979	3.9%	0.43%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**24,929**	**25,908**	**979**	**3.9%**	**0.43%**

The primary differences between the forecasts are the recovery from the recession in the short term as well as a reduction in the estimate of peak demand associated with Energy Efficiency programs.

Demand-Side Management

Demand Response resources expected to be available on-peak for the first year of the assessment include 2,165 MW (summer 2013) of Special Case Resources and 257 MW (summer 2013) of Emergency Demand Response Program (EDRP)

[221] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

resources. These numbers are reported in the "2012 Load and Capacity Data Report."[222] The 2013 forecast of peak demand impact of Energy Efficiency programs is 343 MW (NPCC-New York-Table 3).

The Demand Response resources are held constant over the 10-year assessment period of the NERC LTRA. The cumulative forecast Energy Efficiency impact on peak demand is 1,674 MW by 2017 and 2,324 MW by 2022. The growth of peak demand impact is 650 MW during the second five years of the forecast.

NPCC-New York-Table 3-Demand-Side Management

	Short-Term					
NPCC-New York-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	2,165	2,165	2,165	2,165	0	5.98%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	2,165	2,165	2,165	2,165	0	5.98%
TOTAL ENERGY EFFICIENCY	624	932	1,210	2,324	1,700	6.41%
TOTAL DEMAND-SIDE MANAGEMENT	**2,789**	**3,097**	**3,375**	**4,489**	**1,700**	**12.39%**

The projected levels of Demand Response resources are held constant beyond 2012. The inclusion of Special Case Resources in this manner is an appropriate assumption for planning purposes as these resources can be added or removed with short lead times and are driven by market conditions.

No significant developments or policy implementations are known at this time.

The NYBA's market rules allow for aggregations of demand side resources to provide operating reserves and regulation service.

Generation

The NYBA Area currently enjoys a diverse fuel supply (NPCC-New York-Table 4 and NPCC-New York-Figure 2). Since the last reporting year, new resources totaling 633 MW have come on-line. These include 549 MW of natural gas, 52 MW of wind, and 32 MW of solar. Additionally, there are 182 MW of unit uprates scheduled for 2012. The most significant generator uprate is the 168 MW uprate of a nuclear facility. The NYBA expects the reliance on natural gas as the fuel for new generation to increase over time, and that fuel diversity will decrease as a result.

No current Future-Planned resources are confirmed to come on-line during the assessment period at this time. There are a total of 2,537 MW of Conceptual resources in the NYISO interconnection queue that are at various stages of study that may come on-line over the assessment period. These include 2,198 MW of natural gas, 312 MW of nameplate wind capacity, 21 MW of biomass, and 6 MW of hydro-electric resources.

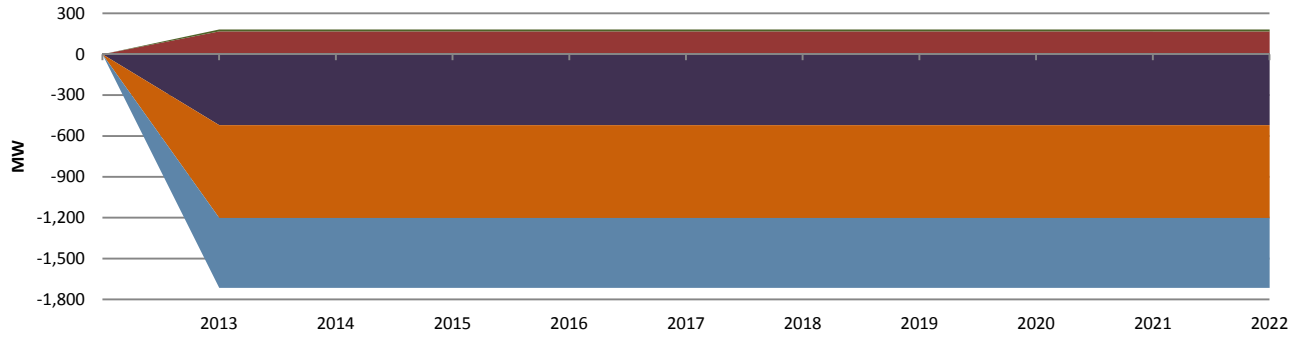
There are a significant number of generators retiring/mothballing that are impacting the NYBA Area this year. Since last year, 1,804 MW of generator retirement/mothball notices have been received. 88 MW of generation retired in 2011. The remaining 1,716 MW are scheduled to retire/mothball during 2012.

[222] http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

NPCC-New York-Table 4-Capacity Outlook[223]

NPCC-New York-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Coal	2,370	6.4%	1,850	5.2%	-520	1,850	4.9%	-520
Petroleum	9,152	24.8%	8,470	24.0%	-682	8,470	22.4%	-682
Gas	14,133	38.3%	13,620	38.6%	-513	15,817	41.8%	1,684
Nuclear	5,431	14.7%	5,599	15.9%	168	5,599	14.8%	168
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	5,771	15.7%	5,786	16.4%	14	6,125	16.2%	353
TOTAL	**36,858**	**100.0%**	**35,325**	**100.0%**	**-1,533**	**37,861**	**100.0%**	**1,003**

NPCC-New York-Figure 2-Summer Net Capacity Change



When the NYISO receives a generator retirement/mothball notice, the NYISO conducts an impact study to determine if reliability issues will arise when the unit shuts down. If no need is determined, then the unit may retire/mothball as planned. However, if a need is determined to exist, follow-up studies are required. If the need is on the local transmission system, the local transmission owner is required to resolve the reliability need. The solution may be that the unit remains on-line as a must-run unit for reliability. If the local transmission owner provides a solution to maintain reliability, the unit may then retire/mothball as planned, providing that the solution is in place prior to the retirement/mothballing date. If the solution will not be in place per the unit's shutdown schedule, the unit may be required to remain in service until the transmission owner's solution is fully implemented. The NYISO would determine the course of action in consultation with the NYS PSC and NYISO stakeholders. Following implementation of the solution, the unit may then enter the retired/mothballed status.

If the Reliability Need is determined to be on the BPS, the NYISO's Comprehensive System Planning Process (CSPP) will study the need in detail as part of the development of NYISO's Comprehensive Reliability Plan (CRP). If the Reliability Needs Assessment (RNA) identifies any violation of Reliability Criteria for bulk power transmission facilities, the NYISO will report a Reliability Need, quantified by an amount of compensatory megawatts or Mvars, and designate one or more Responsible Transmission Owners to develop a regulated backstop solution to address each identified need. In addition, after approval of the RNA, the NYISO will request market-based and alternative regulated proposals from interested parties to address the identified Reliability Need.

Proposed solutions that are submitted in response to an indentified Reliability Need are evaluated in the CRP process and must satisfy Reliability Criteria, including resource adequacy and system security. However, the solutions submitted to the NYISO for evaluation in the CRP do not have to be in the same amounts of compensatory MW/Mvar or the locations reported in the RNA. There are various combinations of resources and transmission upgrades that could meet the needs identified in the RNA. The reconfiguration of transmission facilities and/or modifications to operating protocols identified in the solution phase could result in changes and/or modifications of the needs identified in the RNA.

[223] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

There is only one significant generator uprate occurring over the assessment period. The Nine-Mile nuclear facility will uprate by 168 MW. This will generally have a positive impact on system reliability as nuclear units typically have a very low forced outage rate and scheduled refueling outages are outside peak demand times. The impact will be more noticeable on the operational side as the rated summer capability after the uprate will be 1,309 MW. This exceeds the current 1,200 MW single contingency loss that has been in place for operating reasons and has required that the system carry 1,800 MW of reserves (600 MW 10-minute sync, 600 MW 10-minute non-sync, and 600 MW 30-minute). Operating procedures have been updated to increase the amount of reserves the NYBA carries when the uprate goes into service.

The NYBA neither plans for nor relies on behind-the-meter generation for reliability purposes except for those resources that opt to participate in one of the NYBA's Demand Response Programs.

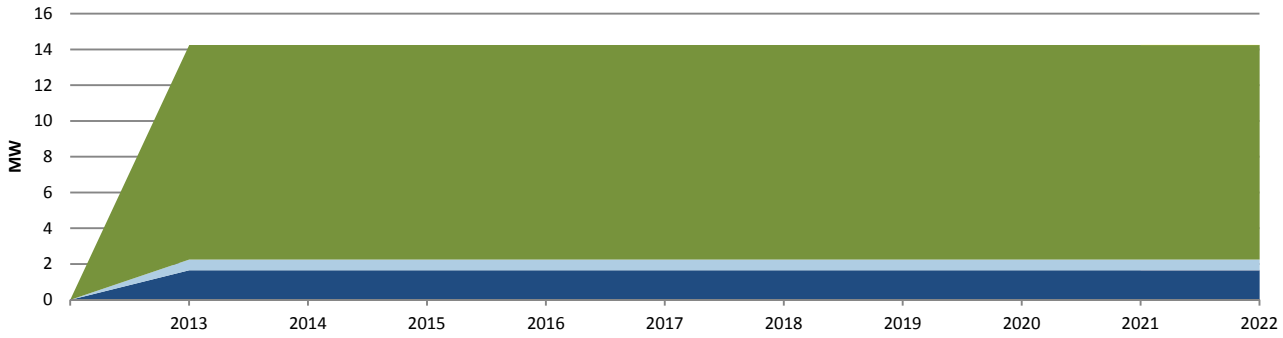
There are only two "non-traditional" resources in the NYBA's markets. A 20 MW flywheel and an 8 MW storage battery are listed in the 2012 Gold Book. There is no impact over the assessment period.

The assumed capacity on-peak for variable resources such as wind, solar, and run-of-river hydro included in this assessment is determined using an expected capability for each resource class based upon unit historic operating data and engineering judgment. On-peak land-based wind resources are rated at 131 MW (nameplate capacity of 1,314 MW). On-peak solar resources are expected at 3 MW (nameplate capacity of 32 MW). On-peak run-of-river hydro resources are expected at 3,827 MW. Biomass landfill gas resources are expected on-peak with a rated capacity of 403 MW (NPCC-New York-Table 5, NPCC-New York-Figure 3, and NPCC-New York-Table 6).

NPCC-New York-Table 5: Renewable Capacity Outlook[224]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-New York-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	3,827	66.3%	3,829	66.2%	2	3,835	62.6%	8
Pumped Storage	1,407	24.4%	1,407	24.3%	0	1,407	23.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	131	2.3%	132	2.3%	1	444	7.3%	313
Biomass	403	7.0%	415	7.2%	12	435	7.1%	33
Solar	3	0.1%	3	0.1%	0	3	0.1%	0
TOTAL	**5,771**	**100.0%**	**5,786**	**100.0%**	**14**	**6,125**	**100.0%**	**353**

NPCC-New York-Figure 3: Summer Net Renewable Capacity Change



[224] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

NPCC-New York-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
NPCC-New York-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	1,311	32	4,282	403	1,317	32	4,285	415
On-Peak Derate	1,180	28	454	0	1,186	28	456	0
EXPECTED ON-PEAK OUTPUT	131	3	3,827	403	132	3	3,829	415

Hourly unit output data is collected for the summer peak hours (2–5 PM) over the June 1 through August 31 period. A derating factor is then calculated for each resource. The unit-specific capacity factors calculated are used in the NYISO's capacity markets and energy markets. However, for reliability studies and planning assessments a more conservative approach is used. Wind resources are assumed to operate at approximately a 10 percent capacity factor and solar resources are expected to operate at a 65 percent capacity factor. Run-of-river hydro resources are given an assumed derate factor of 45 percent to account for the uncertainty in the amount of water available at peak. Biomass and landfill gas resources are modeled with the unit's rated capability and an associated forced outage rate.

Capacity Transactions

Unforced Capacity Deliverability Rights (UDRs) are rights associated with new incremental controllable transmission projects that provide a transmission interface to a NYCA locality where a minimum amount of Installed Capacity must be maintained. Three such projects are currently in service with a total transmission capability of 1,290 MW. A fourth project (660 MW transmission capability with 320 MW Firm capacity rights) is scheduled to be in service for May 2013. Capacity transactions associated with a UDR are considered confidential market data. Only net capacity import/export totals can be provided to maintain market confidentiality.

External capacity (ICAP) purchases and sales are administered by the NYISO. An annual study is performed to determine the maximum level of capacity imports from neighboring control areas allowed without violating the LOLE criteria. Firm imports decline slightly from 2,270 MW in 2013 to 2,220 MW in 2022 while expected imports remain unchanged at 1,353 MMW throughout the assessment period (NPCC-New York-Table 7). Except for grandfathered contracts, these Import Rights are allocated on a first-come, first-serve basis with a monthly obligation. While capacity purchases are not required to have accompanying Firm transmission, adequate external transmission rights must be available to assure delivery to the NYBA border when scheduled. All external ICAP suppliers must also meet the eligibility requirements as specified in the Installed Capacity Manual.

NPCC-New York-Table 7: Projected Capacity Transactions

NPCC-New York-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353
Firm Imports	2,270	2,220	2,220	2,220	2,220	2,220	2,220	2,220	2,220	2,220
TOTAL IMPORTS	3,623	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**3,623**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**

Only Firm contracts longer than one year are considered in planning studies and reliability assessments. These are reviewed annually in the preparation of the annual Gold Book publication.

Only the known duration of any Firm contracts of at least one year are considered in planning studies and reliability assessments.

The NYBA does not rely on emergency imports to maintain reliability. However, transfer capability is reserved on the ties with our neighbors in our planning studies to allow for emergency imports as one potential emergency operating procedure step in the event of a system emergency. These imports would be external to the NYBA.

Transmission

The Hudson Transmission Project (HTP) is a new tie-line between PJM and NYISO from PSE&G's Bergen 230 kV substation to ConEdison's W. 49th Street 345 kV Station. The project consists of a back-to-back HVdc converter in New Jersey with a

submarine 345 kV ac cable from the converter station to New York City. The project will be capable of transferring 660 MW but has Firm capacity withdrawal rights from PJM of 320 MW. The project is currently under construction with a planned in-service date of May 2013. Additional local transmission owner plans include sub-transmission system reinforcements throughout the state. Existing and projected transmission additions are summarized below (NPCC-New York-Table 8).

NPCC-New York-Table 8: NPCC-New York-Table 8: Existing and Projected Transmission

NPCC-New York	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	10,926	66	10,992
Currently Under Construction	0	0	0
Planned - Completed within First Five Years	138	0	138
Planned - Completed within Second Five Years	30	0	30
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	11,094	66	11,160
Conceptual - Completed within First Five Years	0	0	0
Conceptual - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**11,094**	**66**	**11,160**

Historically the most congested transmission paths in New York are Central East, Leeds–Pleasant Valley, and Dunwoodie–Shore Road. Central East and Leeds–Pleasant Valley constraints are driven by demands in the Lower Hudson Valley resulting in high transfers of power from Upstate New York to New York City. The Dunwoodie–Shore Road constraint is driven by Long Island demand. These constraints could be mitigated through additional transmission, generation, or demand reduction.

There are no project delays or temporary service outages for any transmission facilities that will impact long-term reliability during the assessment period.

The NYISO Minimum Interconnection Standard provides that sufficient transmission is constructed to provide reliable access by any given proposed generation project to the New York State Transmission System. In addition, any generation developer seeking to qualify as an Installed Capacity Supplier must meet the NYISO Deliverability Interconnection Standard, which may require the construction of transmission.

The NYISO's role in the interconnection process is that of process administrator, project and system evaluator, and arbiter to ensure that the Project Developer and Transmission Owner collaborate in good faith to keep the project moving forward in a non-discriminatory manner. The process includes the identification and cost allocation of system upgrades necessary for the safe and reliable interconnection to the BPS. This process includes:

- Interconnection Request submission, review, validation and approval;
- Scoping of project, including NYISO receipt of necessary technical data for each;
- Scoping of Feasibility Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conducting Feasibility Study(ies) with final report meeting with Developer and Transmission Owner;
- Scoping of System Reliability Impact Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conducting System Reliability Impact Study(ies) with final report meeting with Developer and Transmission Owner;
- Scoping of Facilities Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conducting Class Year Facilities Study(ies) with system facilities upgrades and capacity deliverability cost allocation, with final report meeting with Developer and Transmission Owner;
- Submission and approval of Class Year Facilities Study(ies) to NYISO Market Participant governance working groups, sub-committees and Operating Committee;
- Decisions of Project Developers to accept or not accept their Project Cost Allocations for system upgrades; and
- Interconnection Agreements provided to Developer, including proof of continued site control and the achievement of development milestones, to be filed with FERC.

As part of the DOE Smart Grid Investment Grant, 888 Mvar of smart grid-enabled capacitor banks will be installed at various sub-transmission voltage levels throughout the state by the end of 2012, and 39 phasor measurement units (PMUs) will be installed at bulk power stations throughout New York by June 2013.

Vulnerability Assessment

The NYBA Area has a significant amount of hydro resources. Many of these resources are located on rivers throughout the state. The output of these run-of-river resources are subject to water levels that may vary greatly on a month-to-month basis based upon weather conditions—snowfall amounts, temperature, and rainfall amounts, etc. For reliability purposes these units are modeled with a 45 percent derate factor. This derate factor represents a severe scenario case for drought or low water level.

There are no expected long-term generator outages over the assessment period. Demand Response resources are modeled conservatively in planning studies to account for the possibility of these resources being unavailable or non-responsive. The NYBA does not rely on distributed generation for reliability.

As the amount of variable resources, such as wind, has been added to the resource mix, procedures have been modified and updated. For example, the NYBA has implemented a centralized wind forecasting program to better estimate the amount of energy to be produced by wind resources over various time frames. There are no planned installations of additional UVLS schemes or Special Protection Systems (SPS) in the NPCC-New York Assessment Area.

The NYISO evaluates extreme contingencies as required by the New York State Reliability Council, such as the loss of all transmission circuits on a common right-of-way, or the sudden loss of a fuel delivery system (i.e., gas pipeline contingencies). The NYISO also evaluates extreme system conditions such as extreme weather or loss of gas supply (i.e., shortage).

Should natural gas supply shortages arise in New York State in the winter, natural gas-fired units could be forced to burn other fuels or curtail operations. Many of the dual-fuel units are the larger and older steam units located in load pockets and would impact reliability needs in multiple ways if they were to retire and if replacement capacity with dual-fuel capability was not available. The real challenge on a going-forward basis will be to maintain the benefits that fuel diversity, in particular dual fuel capability, provides today. This will be especially critical in New York City and Long Island, which are entirely dependent on oil- and gas-fired units, many of which have interruptible gas transportation contracts. In terms of operational strategy, the NYSRC has adopted the following local reliability rule where a single gas facility refers to a pipeline or storage facility:

I-R3. Loss of Generator Gas Supply (New York City & Long Island)

"The NYS BPS shall be operated so that the loss of a single gas facility does not result in the loss of electric load within the New York City and Long Island zones." The NYISO categorizes generation capacity fuel types into three supply risks: Low, Moderate, and High.

The greatest risk to fuel supply interruption occurs during the winter months when both natural gas and heating fuel oils are competing to serve electrical and heating loads. Fortunately in New York, peak electrical loads occur during the summer months when demand is approximately 9,000 MW greater than the winter peak. As such, New York can meet the winter peak of roughly 25,000–26,000 MW with sufficient generation without exposure to significant fuel risks. Even with a forced outage rate of 10 percent, there is sufficient generation in the low to moderate fuel risk categories to meet the winter electrical peak.

On June 25, 2007, FERC Order 698 incorporated by reference NAESB (North American Energy Standards Board) standards to "establish communication protocols between interstate pipelines and power plant operators and transmission owners and operators." The NYISO has met this requirement with the establishment of communication systems to receive notices of system events, including Operational Flow Orders from interstate pipelines serving generators in New York, and by

establishing communication systems to send Energy Emergency Alerts to the Interstate Pipelines. The NYISO will also notify Local Distribution Companies in the event of a system alert. These communication protocols are documented in Attachment BB of the NYISO Open Access Transmission Tariff.

New York has a long history in the active development of environmental policies and regulations that govern the permitting, construction and operation of power generation and transmission facilities. Currently New York's standards for permitting new generating facilities are among the most stringent in the nation. The combination of tighter environmental standards coupled with competitive markets administered by the NYISO since 1999 has resulted in the retirement of older plants equaling approximately 4,000 MW of capacity and the addition of over 9,300 MW of new efficient generating capacity. In turn, these changes have led to a marked reduction of power plant emissions and a significant improvement in the efficiency of the generation fleet.

Notwithstanding the progress toward achieving New York's clean energy and environmental goals, various environmental initiatives are either in place or pending that will affect the operation of the existing fleet. Environmental initiatives that may affect generation resources may be driven by either or both the state and federal programs. Since the prior LTRA, the USEPA has promulgated several regulations that could affect most of the thermal fleet of generators in NYCA. Similarly, the New York State Department of Environmental Conservation (NYSDEC) has undertaken the development of several regulations that will apply to most of the thermal fleet in the state.

The NYISO performs analysis to gain insight into the population of resources that are likely to be faced with major capital investment decisions in order to achieve compliance with several evolving environmental program initiatives. The premise of this analysis is that the risk of unplanned retirements is related to two factors: first, the capital investment decisions resource owners need to make in order to achieve compliance with the new regulatory program requirements, and secondly, the recent change in the relative attractiveness of gas versus coal has challenged the viability of some base-load units. The goal of this scenario analysis is to identify when and where these risks occur on the New York Power System.

Five environmental initiatives are sufficiently broad in application and have requirements that potentially may require retrofitting environmental control technologies. Therefore Generator Owners will likely need to address the retirement versus retrofit question. These environmental initiatives are NYSDEC's Reasonably Available Control Technology for Oxides of Nitrogen (NOx RACT), Best Available Retrofit Technology (BART), Best Technology Available (BTA) for cooling water intake structures, the USEPA's Mercury and Air Toxics Standards (MATS), and the Cross State Air Pollution Rule (CSAPR), which is currently under review in court.

NOx RACT

The NYS DEC finalized new regulations for the control of emissions of nitrogen oxides (NOx) from fossil-fueled power plants (Part 227-2). The regulations establish presumptive emissions limits for each type of fossil-fueled generator and each fuel used as an electric generator in New York that has a capacity greater than 25 MW. Compliance options include averaging emissions with lower emitting units, fuel switching, and installing emissions reduction equipment such as low NOx burners or combustors, selective catalytic reduction units, or retirement. Generators were required to file permit applications and a RACT analysis with NYSDEC by January 1, 2012. Compliance with approved plans is required by July 1, 2014. The plans have been reviewed. Several generators have requested that their submittals be considered Competitive Business Information; however, NYSDEC has denied these requests.

Reviewing the plans that are public, the rule applies to approximately 28,000 MW of capacity, of which approximately 4,000 MW is involved in emissions reduction projects. Some of these projects are underway, and the NYISO is informed that the balance should be able to be accomplished prior to the July 2014 compliance date.

BART

The NYSDEC recently promulgated a new regulation: Part 249, Requirements for the Applicability, Analysis, and Installation of Best Available Retrofit Technology (BART) Controls. The regulation applies to fossil-fueled electric generating units with

approximately 8,200 MW of capacity built between August 7, 1962 and August 7, 1977, and is necessary for New York State to comply with provisions of the federal Clean Air Act that are designed to improve visibility in National Parks. The regulation requires an analysis to determine the impact of an affected unit's emissions on visibility in national parks. If the impact is greater than a prescribed minimum, then emissions reductions must be made at the affected unit. The compliance deadline is January 1, 2014. Emissions control of sulfur dioxide (SO2), nitrogen oxides (NOx) and particulate matter (PM) may be necessary. Compliance plans were filed with NYSDEC in October 2011. In April, USEPA announced that it had accepted some plans, was awaiting further administrative actions on other plans and had declared specific lower emissions limits for other plans. Several small units have chosen to retire, representing a capacity loss of less than 50 MW. Other plants will achieve the required emissions reductions through the use of cleaner fuels, while others are undertaking retrofit projects. Approximately 500 MW of capacity may be needed to undertake a major emissions reduction project or switch to cleaner fuels, or shut down.

BTA

The NYS DEC has finalized its policy document "Best Technology Available (BTA) for Cooling Water Intake Structures." The policy applies to plants that use once-through cooling with design intake capacity greater than 20 million gallons/day. The policy prescribes reductions in fish mortality and establishes performance goals for new and existing cooling water intake structures. The performance goals call for the use of wet, closed-cycle cooling systems at existing generating facilities. The policy does provide some limited relief for plants with historical capacity factors less than 15 percent. The policy is applied at the time that the generating facility's State Pollution Discharge Elimination System (SPDES) Permit is renewed, which is theoretically a five-year period.

Generators with approximately 18,000 MW of capacity are subject to this policy. Of that total, generators with 4,000-7,000 MW may need to retrofit their cooling water intake technology. If cooling tower retrofits are required, compliance deadlines will be project-specific.

Mercury and Air Toxics Standards

The USEPA announced the final rule in December 2011. The final rule replaced what had been known as the Maximum Achievable Control Technology, or MACT Rule. The rule establishes limits for Hazardous Air Pollutants (HAPs)—for acid gases, Hydrogen Chloride (HCl), Hydrogen Fluoride (HF), Mercury (Hg), and Particulate Matter. Alternative limits were also established. These limits apply to coal- and oil-fired generators. The compliance date is March 2015. The NYS DEC may provide an additional year to comply if necessary. Further, reliability critical units can qualify for another year to achieve compliance if retrofitting emissions control technology is required or if the reliability improvement project will take an additional year to comply. 11,331 MW of capacity in New York will be affected by this regulation. The USEPA established a subcategory for limited use oil-fired generators. Units that maintain a capacity factor on oil that is less than 8 percent will be more lightly regulated. No oil-fired EGUs exceeded the 8 percent Capacity Factor when firing oil in 2009 and 2010. While these units will remain subject to MATS, it is not expected that significant emissions control retrofit projects will be required at these units.

A review of emissions records was done to determine the best level of emissions reductions that has been shown to be sustainable. These emissions levels were compared to those necessary to comply with MATS for coal-fired units. This review shows that most of the coal-fired units in New York are already capable or nearly capable of complying with MATS. In addition, NYS DEC has promulgated Part 246: Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units, which establishes emissions limitations that are currently in effect in New York to reduce mercury emissions. Phase II of this regulation requires additional reductions from coal-fired boilers in 2015. The Phase II emissions limitations are more stringent than the USEPA MATS limits.

CSAPR

The USEPA finalized the Cross State Air Pollution Rule (CSAPR) in December 2011. The rule is designed to reduce interstate transport of emissions of SO2, Annual NOx and Ozone Season NOx from fossil-fueled power plants in 28 central and eastern

states. The regulation is implemented through the use of emissions allowances and limited trading programs. The regulation establishes emissions budgets for each affected state. The emissions budget is then divided on a pro-rata basis determined by historic heat input for existing facilities. There are set-asides to provide allowances to new fossil generators. The use of emissions allowances will be expected to increase offering prices for generation from affected facilities. The final rule was placed under a stay by the United States District Court. However, for the stay, the rule would be in effect currently with another reduction in the SO2 cap scheduled for 2014. While this rule is currently the subject of an appeal, the NYISO has included the impact from the rule in its analysis because the Clean Air Act requires the USEPA to address interstate pollution transport in some form. CSAPR is the USEPA's revision of the Clean Air Interstate Rule (CAIR), which was vacated by the U.S. Supreme Court. In doing so, the Court ordered that CAIR remain in effect until such time as a replacement rule is implemented. In December when the District Court stayed the CSAPR rule, it ordered that CAIR be reinstated. CAIR as promulgated has a significant reduction in allowable emissions scheduled for 2015. It is reasonable to assume that a national program will be in effect for limiting emissions of SO_2 and NOx via a cap-and-trade program in the early part of the planning horizon. The CSAPR rule will be used to evaluate the potential impact of that program.

The CSAPR rule applies to most of the fossil-fueled fleet with nameplate capacity greater than 25 MW. The rule will require the use of allowances in numbers equivalent to actual emissions tonnages for three categories: SO_2, Annual NOx, and for Ozone Season NOx. The annual budget for each of the states in the program has been established by USEPA through the use of long-range transport models to identify sources and sinks for impact of emissions on areas in other states. The budget of allowances for each of the three categories is distributed based upon each affected unit's pro-rata share of historic heat input. A small set-aside is established for new units, and recently retired units continue to receive allowances for a limited time period. The rule calls for a two-phase reduction of SO_2, while the limits for Annual NOx and Ozone Season NOx are fixed. The program limits the amount of allowances that can be obtained through trading with Generator Owners in other states. The total of the budget plus allowed traded allowances is known at the "Assurance Level." Should a state's emissions exceed the Assurance Level, two additional allowances would need to be surrendered for each ton of excess emissions. This penalty would be pro-rated across all emitters who exceeded their direct allocation plus the allowed trading percentages.

Historic emissions and inventories of installed emissions control equipment have been reviewed to estimate the level of additional emissions reductions required. As detailed in the figure below, with optimum operation of existing environmental control equipment and fuel switching, New York State should be able operate within the Assurance Level.

The NYISO has conducted the analysis described above to identify generating units that are subject to key environmental initiatives. The analysis also estimated the amounts of capacity that would be potential candidates for retrofits and thus require recapitalization. These units could become unplanned retirements. The analysis then was extended to identify the amounts of capacity that are subject to multiple environmental requirements. The bi-annual Reliability Needs Assessment conducts scenario evaluations. In particular, the results of an analysis of the NYISO "zones at risk" are compared to the amount of capacity that could be considered at risk for unplanned retirement due to the need for capital expenditures to retrofit environmental control technology.

GE conducted a study of the amount of time necessary for NOx emissions control retrofits. The study concluded that required retrofit installations could be covered within the time frame of major turbine/generator overhaul. It is reasonable to expect that other outages necessary for emissions control technology retrofits would require similar time periods for equipment tie-in. Given the time horizon for outage scheduling and the capacity balance in NYBA Area, it is reasonable to conclude that bulk system reliability will not be negatively affected.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

The NYISO has reviewed compliance plans that have been filed by generators for NYSDEC's NOx RACT and BART programs, as well as, USEPA notices on acceptance or modifications to those plans. The plans were obtained from NYSDEC through a Freedom of Information Law request.

The generators are not required to file compliance plans with NYSDEC for MATS compliance. They are however, required to notify the NYISO by March of 2013 if they intend to seek additional time to comply with MATS. To date, no such notifications have been received.

The USEPA recently announced that it will take another year to finalized regulations for cooling water systems that use public waters. In the interim, NYSDEC will continue to administer its Best Technology Available Policy on a case by case basis as permits are renewed. The NYISO meets periodically with NYSDEC to review the status of permit renewals.

A three-judge panel of the United States Court of Appeals for the District of Columbia Circuit vacated CSAPR and the Transport Rule Federal Implementation Plans, in an order issued August 21, 2012. The Court remanded the proceeding to the EPA and ordered it to continue to administer CAIR pending a valid replacement. Consequently, generators have not announced any compliance plans relative to this program. The table below has been updated to reflect increases in New York's CSAPR Allowance Budget that have been announced by USEPA, as well as, to take into account recently announced retirements (NPCC-New York-Table 9).

NPCC-New York-Table 9: NY State Emission Allocation under CSAPR

	2012 SO2	2014 SO2	Annual NOX	Ozone Season NOX
A. Allocation for Units Proposed to be In-Service	26,060	19598	16,334	7,898
B. Retired Units [2] + Non-EGU Allocations [3] + Miscellaneous [4]	9,510	7407	4,954	2,264
C. New Unit Set-Aside	726	551	434	207
D. Total Allocation (A+B+C)	36,296	27,556	21,722	10,369
E. Trading Variability for 2014 (18% Annual, 21% Ozone Season)	N/A	4960	3,910	2,177
F. 2014 Assurance Level (D+E)	**N/A**	**32,516**	**25,632**	**12,546**
Historic Emissions				
G. 2011 Emissions from Units Proposed to be In-Service		24,020	17,153	8,533
H. Estimated 2011 In-Service Unit Emissions - Best Demonstrated Performance (2011 Actual Heat Input Lowest Annual Emissions Rate from 2006-2011)		14,972	13,076	6,765
I. 2011 "New Unit" Emissions		11	134	58

[1] Linked Cogeneration Facility is not included.
[2] Retired Units Include: Poletti, Projec Orange, Greenidge, Westober, Ogdensburg Cogen, Astoria Generating ST2 and 4, Glenwood ST 4 and 5, Far Rockaway ST4, Dunkirk 1-4, and AES Cayuga.
[3] Three (3) Consolidated Edison Steam System Boilers were given allocations.
[4] EPA calculation and rounding error.

The NYISO's Draft 2012 Reliability Needs Assessment[225] considers a scenario where all coal fired units are retired. The study can be found on the NYISO website.[226] The study found that the retirement of all coal units would accelerate the year of need to 2019 from 2020. The table below identifies the programs, their current status, compliance dates, quantities of capacity affected and announced and estimated quantities of capacity that is expected to undergo retrofits of environmental control equipment (NPCC-New York-Table 10).

NPCC-New York-Table 10: Other Environmental Regulation Status, Compliance Deadlines, and Potential Impacts in New York

Rule/Legislation	Status	Compliance Deadline	Approximate Capacity Affected	Potential Retrofits
Nox RACT	In Effect	Jun-14	26,700	6,000 MW
			238 Units	23 Units
BART	In Effect	Jan-14	8,600 MW	1,800 MW
			19 Units	5 Units
MATS	In Effect	Mar-15	10,300 MW	400 MW
			28 Units	2 Units
BTA	In Effect	Upon Permit Renewal	16,900 MW	4,400 MW -7,300 MW
			39 Units	-
CSAPR	Stayed While in Litigation	January 2012 and January 2014	25,000 MW	2,400 MW
			156 Units	11
RGGI	In Effect	In Effect	25,000 MW	-
			158 Units	-

Generator Owners and Operators have not informed the NYISO that they will be unable to meet the compliance deadlines established in these programs. The NYISO has procedures in place to approve outages and will use these procedures to maintain reliability of the system during the periods of retrofit installations.

[225] The draft RNA will not be final until the Board approves the report in September.
[226] http://www.nyiso.com/public/markets_operations/committees/meeting_materials/index.jsp?com=mc.

The Astoria 345/138 kV transformer and phase angle regulator were installed in 2012 between Astoria Annex 345 kV and Astoria East 138 kV to maintain reliability on the non-bulk system in response to the mothballing of generation units Astoria 2 and Astoria 4. Non-bulk transmission needs have been identified in Western New York in association with the mothballing of the Dunkirk coal plant. Transmission solutions have not yet been finalized. Transmission needs relating to the integration of new generation are addressed on a class year basis in accordance with the NYISO Open Access Transmission Tariff.

Following the completion of the NYISO 2012 Reliability Needs Assessment, the NYISO will request market solutions (including transmission, generation, or demand response) to address any reliability needs.

Standing and Emerging Reliability Issues

The NYBA identified two issues in the 2011 NERC LTRA narrative that could continue to impact reliability over the long-term assessment period. They were a) the impact of federal and state environmental regulations, and b) project lead times. For this report, the two issues remain as standing reliability issues.

The potential impact to system reliability due to state and federal environmental regulations is a standing reliability issue as discussed in last year's NERC LTRA. There are five major environmental initiatives that have requirements that may potentially require retrofitting environmental control technologies.

The timing of reliability impacts will vary with the compliance date of various environmental initiatives. Generator units affected by BART must comply by January 1, 2014. BTA policy rules will be applied at the time the State Pollution Discharge Elimination System Permit is renewed, which is theoretically over a five-year period. Compliance deadlines will be project-specific. Units that must comply with the Mercury and Air Toxic Standards have until March 2015. Units subject to the NOx RACT regulations have until July 1, 2014 to comply. Units subject to CSAPR regulations must comply in 2015.

The primary drivers are to reduce the amount of power plant emissions into the environment and to increase the efficiency of the generation fleet by encouraging the building and utilization of more efficient, more environmentally friendly resources.

Environmental regulations may lead some generation resources to retire, as the cost to meet the new regulations may not be economical for some units. Depending upon the regulation, as low as 500 MW to as much as 28,000 MW may be affected. The impact will depend upon the amount and location of the retiring generation.

BPS reliability could be affected if critical units that support the BPS are retired. However, as the NYBA, the NYISO has the authority to designate the Responsible TO or Responsible TOs to proceed with a regulated backstop solution in order to maintain system reliability in the event that market-based solutions do not materialize to meet a reliability need in a timely manner. The impact on BPS reliability due to generator retirements is for the most part localized, where following the retirement the transmission in the affected area is relied upon more heavily to serve load in that area. Certain generator retirements or combinations of retirements may result in the need for significant transmission upgrades absent other generator or Demand Response solutions.

The bulk power transmission facilities could be affected if critical units that support the BPTF are retired. However, the NYBA has the authority to designate the Responsible TO or Responsible TOs to proceed with a regulated backstop solution in order to maintain system reliability in the event that market-based solutions do not materialize to meet a reliability need in a timely manner. The impact would be dependent upon the criticality of the need being resolved.

If generation units ultimately retire as a result of environmental issues, the Planning Reference Margin would be adjusted accordingly. This would also affect the total MW of generation capacity and the fuel mix of the resources reported. Generation retirements would affect the total MW of generation capacity and the fuel mix of the resources reported and would also have the potential to impact the entire Assessment Area.

When reliability needs are identified, solutions (generation, transmission, or Demand-Side measures) are solicited through the NYISO's Comprehensive System Planning Process. Competitive market-based solutions are given first priority because of

their reduced risk to rate-paying consumers**.** Given the potentially short notice period coupled with the potentially significant impact, gap solutions or regulated backstop solutions may be necessary in some situations if market solutions do not respond in time.

If generation units shut down in response to the regulations, the vulnerability of the system may increase due to the decrease in resources. The NYISO would respond by invoking regulatory backstop solutions or gap solutions as required by the circumstances.

The project lead time issue was identified in the *2012 Long-Term Reliability Assessment*. Long project lead times may affect reliability over the assessment period depending upon the impact of the environmental initiatives on the NYBA Area's fleet.

Considerable lead time is required for power infrastructure project execution, given the time frames needed to finance, permit, and construct major energy projects. The planning horizons of policy makers and regulators should encompass the time required for the electric industry to address new laws and changes in regulatory requirements.

Resource adequacy is a function of the amount of generation resources available to meet the system load. If resources are not added in a timely manner to meet projected demand, reliability may be negatively impacted. The impact would vary depending upon the timing and scope of the need.

This issue may affect the BPS reliability if projects critical to maintaining reliability are delayed because of the process.

This issue may affect the bulk power transmission facilities if projects critical to maintaining reliability are delayed because of the process. The impact would depend upon the timing and scope of the need.

The estimated in-service dates for Conceptual resources may be pushed back further due to time considerations (assuming the project moves forward to construction). This would affect the Adjusted Potential Reference Margin Level with minimal impact on the overall assessment.

When reliability needs are identified, solutions (generation, transmission, or Demand-Side measures) are solicited through the NYISO's Comprehensive System Planning Process. Competitive market-based solutions are given first priority because of their reduced risk to rate-paying consumers. Ultimately, if generation units are not built in a timely manner to meet system demand, the impact to BPS reliability may increase.

NPCC-Ontario

Planning Reserve Margins

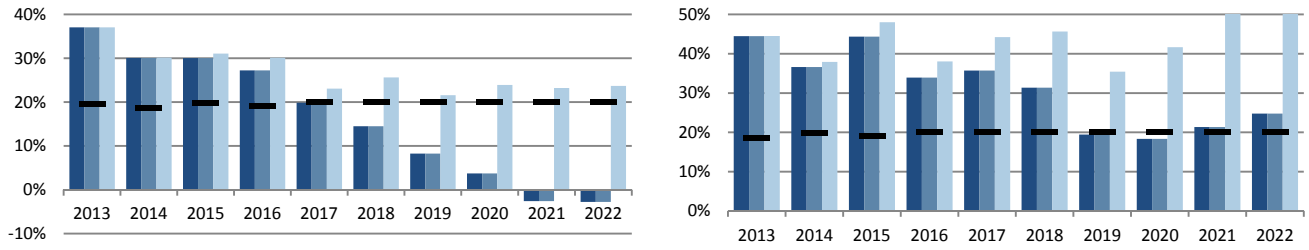
Ontario is projecting adequate Planning Reserve Margins throughout the assessment period (2013– 2022). The required reserve levels are determined based on probabilistic methods deemed by NPCC to be acceptable for meeting regional Loss of Load Expectation (LOLE) criteria. The target Reserve Margin levels for the first four years vary from 19.7 percent in 2013 to 19.2 percent in 2016. The OPA target Reserve Margin of 20 percent is applied from 2017–2022 (NPCC-Ontario-Table 1 and NPCC-Ontario-Figure 1). These targets are applied as the NERC Reference Margin Level throughout the assessment period.

NPCC-Ontario Table 1: Planning Reserve Margins

NPCC-Ontario-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		37.07%	30.08%	30.03%	27.22%	19.88%	14.50%	8.24%	3.72%	-2.58%	-2.78%
PROSPECTIVE		37.07%	30.08%	30.03%	27.22%	19.88%	14.50%	8.24%	3.72%	-2.58%	-2.78%
ADJUSTED POTENTIAL		37.07%	30.14%	31.07%	30.11%	23.08%	25.62%	21.57%	23.90%	23.21%	23.69%
NERC REFERENCE	-	**19.70%**	**18.60%**	**19.80%**	**19.20%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

NPCC-Ontario-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		44.47%	36.63%	44.36%	33.94%	35.73%	31.35%	19.45%	18.33%	21.33%	24.75%
PROSPECTIVE		44.47%	36.63%	44.36%	33.94%	35.73%	31.35%	19.45%	18.33%	21.33%	24.75%
ADJUSTED POTENTIAL		44.53%	37.92%	48.01%	38.02%	44.25%	45.65%	35.44%	41.69%	50.95%	55.04%
NERC REFERENCE	-	**18.60%**	**19.80%**	**19.20%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

NPCC-Ontario-Figure 1: Summer (Left) and Winter[227] (Right) Planning Reserve Margins



The Adjusted Potential Planning Reserve Margins remains above the required Reserve Margin for all 10 years. The supply mix and the system demand affect the level of Planning Reserve Margin Requirements. On February 17, 2011, the Government of Ontario issued a Supply Mix Directive that specified the government's goals, including a target of renewable capacity. The cumulative renewable resources target by end of 2018 is 10,700 MW for renewables such as wind, solar, and bio energy, and 9,000 MW for hydro-electric capacity. These resources would be accommodated through transmission expansion and by maximizing the use of the existing transmission and distribution systems. The amount of variable generation such as wind, solar, and run-of-river hydro is expected to increase over time, and the integration of these variable generation resources will influence the level of planning reserve that is required for the long term.

In assessing reserves for the next decade, the IESO has made allowance for long-term refurbishment outages for the nuclear units at the Bruce and Darlington Nuclear Generating Stations. To extend their lives, these units will be out of service for about three years while being refurbished. There is considerable uncertainty about when these refurbishment outages will actually occur, as a number of options exist for extending life expectancy. Until formal programs are established by the station owners, the IESO will continue to assume nuclear reductions occur in sequence in the latter half of the 10-year period. As the supply mix continues to change, the level of planning reserve will need to be reassessed. In addition to generation, the projected demand with respect to its load shape and the expected peak values can also influence the level of Planning Reserve Margins.

[227] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Anticipated and Prospective Planning Reserve Margins are projected to be below the NERC Reference Margin Level in 2017. However, the Total Potential and Adjusted Potential Reserve Margins are expected to stay above the target margin for the entire period. Some of the Bruce and Darlington units will be out of service for refurbishment in this time frame.

Ontario's planning process considers expected and potential unit refurbishments or retirements and proposes ways to meet resulting resource requirements. Specific considerations include the procurement of conservation programs, renewable resources, new gas-fired units, and refurbished nuclear resources. In addition, the process considers the transmission expansion that would be required to integrate all of the above-mentioned resources. Other options include developing greater coordination and flexibility related to nuclear refurbishment outages and converting existing coal stations to alternate fuels. Mitigation of reliability concerns is to be supported through ongoing monitoring, assessment, measurement, and verification.

The IESO and the OPA recognize the potential for certain adverse conditions (such as extended forced outages, drought conditions, and particular fuel interruptions) to result in higher than expected resource unavailability, and therefore establish planning reserves sufficient to handle many of these conditions. To the extent resource procurement exceeds the planning reserve requirements, resource adequacy can be maintained for higher than normal contingencies. However, there are always conditions that can exceed those planning assumptions. In such adverse situations, the IESO's operations would rely on interconnection support and available control actions to maintain system reliability. Through retention and further development of a diverse resource mix, the potential consequence of these events is reduced.

Demand

This year's electricity Net Energy for Load forecast net of conservation has an average annual growth rate of -0.3 percent over the period 2012-2022 compared to last year's average growth of -0.1 percent for the years 2011-2021. The rate of growth for overall consumption is lower than the peak growth rates. Initially conservation was aimed at reducing peaks, but as those peak reduction opportunities are realized, conservation and embedded generation will start impacting overall energy demand. Peak demand for the summer season grows by only 0.7 percent between 2013 and 2022 (NPCC-Ontario-Table 2).

NPCC-Ontario-Table 2: Demand Outlook

NPCC-Ontario-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	23,301	23,442	142	0.6%	0.07%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**23,301**	**23,442**	**142**	**0.6%**	**0.07%**

NPCC-Ontario-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	22,192	21,529	-663	-3.0%	-0.34%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**22,192**	**21,529**	**-663**	**-3.0%**	**-0.34%**

With the underlying drivers being very similar to last year, the forecasts' growth rates remain similar as well. Although Canada is expected to post respectable growth over the forecast, Ontario will lag the nation's growth in the near term. High commodity prices—in particular oil—will benefit other parts of Canada over Ontario's manufacturing and export-based economy. In fact, Canada's oil wealth puts upward pressure on the dollar, which is more detrimental to central Canada.

Over the forecast horizon Ontario's economy will continue to undergo structural change. As the economy matures, there is a transition from an energy-intense industrial process based economy to one with a larger service sector and specialized or high-value-added manufacturing. This will lead to a less energy-intense economy.

The forecasting methodology has not changed since last year's forecast. The models have been updated and re-estimated to incorporate the latest information regarding the relationship between electricity demand and the economy, demographics, and weather.

Load growth has been relatively flat in recent years, and this trend is expected to continue as Ontario demand is subject to two opposing forces. Pushing higher peak and energy demands are population growth and economic expansion. Acting to

restrain that underlying growth are increased conservation initiatives, increased embedded generation capacity and, for peaks in particular, time-of-use rates.

Within Ontario there has been some localized variation in demand. The Toronto and southwest part of the province make up the vast majority of the provincial demand and in essence drive the provincial numbers. Changes in the industrial composition in the north have had a significant impact on demand patterns and will continue throughout the forecast. The northwest part of the province has been in decline due to reductions in the forestry and pulp and paper sectors. The northeast has more mines and has benefited from strong commodity prices and raw material demands from emerging nations. These underlying trends are expected to continue. There is significant potential for mineral extraction in the Ring of Fire Area of northern Ontario, which could be a source of significant load growth. At present this potential impact is speculative and has not been factored into the forecast.

Demand-Side Management

The IESO treats Demand Response as a resource and conservation as a decrement to demand. In 2013 there is just over 1,500 MW of effective Demand Response Capacity available during peak periods. At the time of the 2013 peak, conservation impact is estimated to be roughly 500 MW higher when compared to 2012.

In the final year of the forecast, effective Demand Response Capacity is expected to be 1,687 MW. Also at the final year, total incremental peak conservation savings (or Energy Efficiency) are projected to be 3,710 MW (NPCC-Ontario-Table 3).

NPCC-Ontario-Table 3: Projected Demand-Side Management

	Short-Term					
NPCC-Ontario-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	1,529	1,665	1,668	1,687	158	7.20%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	1,529	1,665	1,668	1,687	158	7.20%
TOTAL ENERGY EFFICIENCY	793	1,285	1,734	3,710	2,917	15.82%
TOTAL DEMAND-SIDE MANAGEMENT	**2,322**	**2,950**	**3,402**	**5,397**	**3,075**	**23.02%**

The growth in Demand Response Capacity is relatively small over the forecast but plateaus in 2015–16.

Demand Response programs in Ontario are treated as a supply resource with discounted capacities associated with the unique characteristics of each program (e.g., voluntary/Firm contracts). The OPA manages contracts for the majority of the Demand Response programs scheduled to be activated over the forecast time frame. Programs with Firm contracts to reduce demand during periods of high demand/tight supply are expected to provide a reliable and verifiable supply resource. Most Demand Response programs are market-based and are triggered by market prices or supply cushion conditions.

Energy Efficiency and conservation are decremented from demand. These programs are run and delivered by distributors and the OPA. As well, changing efficiency standards and building codes also contribute to conservation savings. The savings are projected to grow throughout the forecast.

The capacity of Demand Response programs is relatively static throughout the forecast, with only some small incremental growth.

The IESO does not have ancillary service Demand Response programs.

Generation

At the time of this assessment in 2012, the total Existing-Certain Capacity Resources connected to the IESO-controlled grid is 29,500 MW. The Existing-Other and Existing-Inoperable capacity amounts to 4,800 MW and 28 MW, respectively.

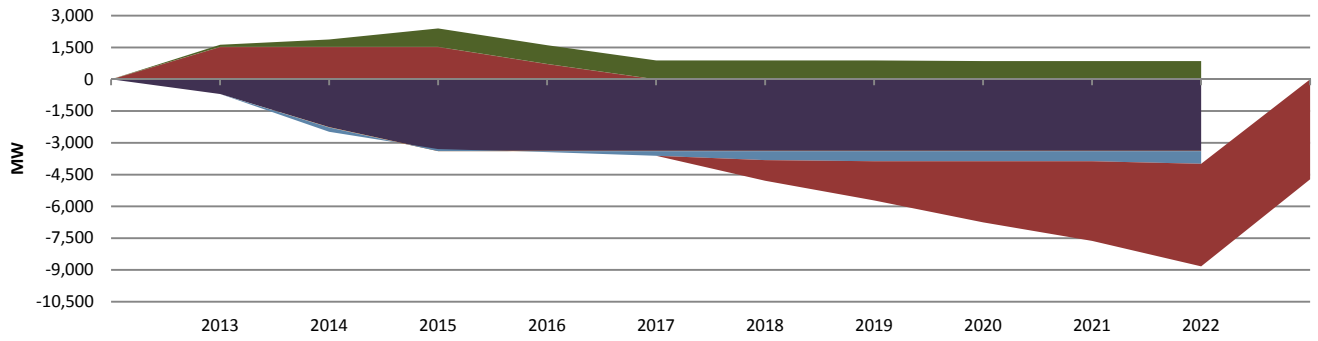
The primary sources of fuel in Ontario are nuclear, gas or oil, water, and coal. More than 50 percent of the electrical energy is generated with nuclear. Coal-fired generation will cease operation by the end of 2014. More than 5,600 MW of gas-fired

generation has been added over the last 10 years. About 1,500 MW of grid-connected wind is in operation, with another 200 MW in final stages of commissioning. Future-Planned projections indicate an increase in renewable capacity, to 7,011 MW by 2022 (NPCC-Ontario-Table 4 and NPCC-Ontario-Figure 2).

NPCC-Ontario-Table 4: Capacity Outlook[228]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-Ontario-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	3,377	11.2%	0	0.0%	-3,377	0	0.0%	-3,377
Petroleum	2,148	7.1%	2,134	7.7%	-14	2,134	7.5%	-14
Gas	6,439	21.4%	6,439	23.3%	0	10,274	36.1%	3,834
Nuclear	12,011	39.9%	12,011	43.5%	0	7,290	25.6%	-4,721
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	6,156	20.4%	7,011	25.4%	855	8,782	30.8%	2,627
TOTAL	**30,131**	**100.0%**	**27,595**	**100.0%**	**-2,536**	**28,480**	**100.0%**	**-1,651**

NPCC-Ontario-Figure 2: Summer Net Capacity Change



Since last year, 227 MW of wind and 438 MW of gas generation have come into service. There are 8,782 MW of Future-Planned and Conceptual renewables resources that are expected to come on-line throughout the assessment time frame. Of this, about 200 MW are expected to come from the coal to biomass conversion at the Atikokan Generating Station, which is expected to take place by 2014. The remaining new capacity is mostly comprised of generation from the Feed-In Tariff (FIT) and microFIT programs, and from the Green Energy Investment Agreement. The Future-Planned and Conceptual renewable resources will meet the Government of Ontario's target of 10,700 MW of renewables other than hydro-electric and 9,000 MW of hydro-electric capacity by 2018. Two units at Bruce A Nuclear Generating Station are being refurbished and are expected to add 1,500 MW. In the latter half of the 10-year period, a number of nuclear units at Bruce and Darlington Nuclear Generating Stations will be expected to undergo refurbishment.

Two more coal units at Nanticoke Generating Station with a total capacity of 980 MW were shut down in December 2011. The remaining nine coal-fired units across four facilities in the province will be phased out by 2014. Pickering Nuclear Generating Station is scheduled for retirement by 2016, but the technical feasibility of extending the operating life of the Pickering generating units is being studied with a decision expected within next year. If feasible, it would provide the option to continue to operate the units at Pickering Nuclear Generating Station through to 2020. In September 2011, a 280 MW gas plant under construction in Mississauga was cancelled. This project had been scheduled to be in service by the third quarter of 2014. There is work currently underway to determine relocation options for this plant. No other major generation or transmission projects have been cancelled or significantly deferred that affect reliability.

By 2014, all coal-fired energy in the province will be phased out. Plans are moving forward for the conversion to biomass of the 205 MW Atikokan Generation Station in northwestern Ontario. In addition, two units at the Thunder Bay Generating Station in northwestern Ontario are candidates for conversion to natural gas over the period leading up to 2014.

[228] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Conversion of some or all of the remaining coal-fired units at Lambton and Nanticoke to natural gas will be assessed, in conjunction with other options, under a range of different scenarios.

Ontario Power Generation's Lower Mattagami expansion project, which is currently under construction, will add 438 MW of hydro-electric capacity to Ontario's electricity system. In addition, by 2013 the new Niagara Tunnel will allow OPG to generate a further 1.6 billion kilowatt-hours of electricity annually.

About 1,500 MW of nuclear capacity is expected to be brought back into service from the re-start of units 1 and 2 at Bruce A Nuclear Generating Station in the short term. In the years following the 2014 coal phase-out, the province's next reliability challenge will be to carefully manage the renewal of its nuclear fleet. The technical feasibility of extending the operating life of the units at Pickering Nuclear Generating Station is being studied, and an update is expected within next year. If feasible, it would provide the option to continue to operate the units at Pickering Nuclear Generating System through to 2020. Units at Bruce B and Darlington Nuclear Generating Station are expected to reach the end of their service lives over the next decade. To extend their lives, these units will be taken out of service for refurbishment. Supply options for maintaining resource adequacy over this time period are under review and include, among others, new gas generation or conversion of some or all of the Lambton and Nanticoke coal-fired units to natural gas.

Over the assessment time frame, the level of renewables penetration will be expected to increase significantly through the FIT and microFIT programs. This in turn will increase the level of behind-the-meter generation. Much of this generation could be variable in nature, which adds more volatility as on-grid demand is impacted both by underlying demand and by variable generation within the distribution system. The majority of distribution-connected generation is expected to be solar, with lesser amounts of wind.

While a vast number of storage technologies are available for development, five are particularly promising and are being developed by companies within Ontario. These include batteries, pumped hydro, compressed air energy storage (CAES), flywheels and hydrogen storage. While most of these technologies are only recently seeing major development for grid applications, some technologies have a long history in the province, such as hydro-electric pumped storage at the Sir Adam Beck Pump Generating Station in Niagara Falls.

While all these technologies offer energy storage, each provides its own specific utility to the grid. Short-term storage systems that can supply power for less than two minutes are generally used for frequency regulation and to maintain grid power quality. Technologies such as batteries and larger flywheels can supply medium-term storage providing frequency regulation and ramping capabilities and can help improve system reliability. Long-term supply can be provided from technologies such as pumped hydro, CAES, hydrogen and some battery technologies that are capable of lasting more than one hour. These solutions among others can be used to increase grid capacity, offering Firm output. Energy storage can also defer transmission and distribution system upgrades if installed in the right location.

As renewables make up an increasingly large portion of the supply, energy storage systems can address some of the problems caused by the intermittent nature of some renewable energy sources, such as wind and solar.

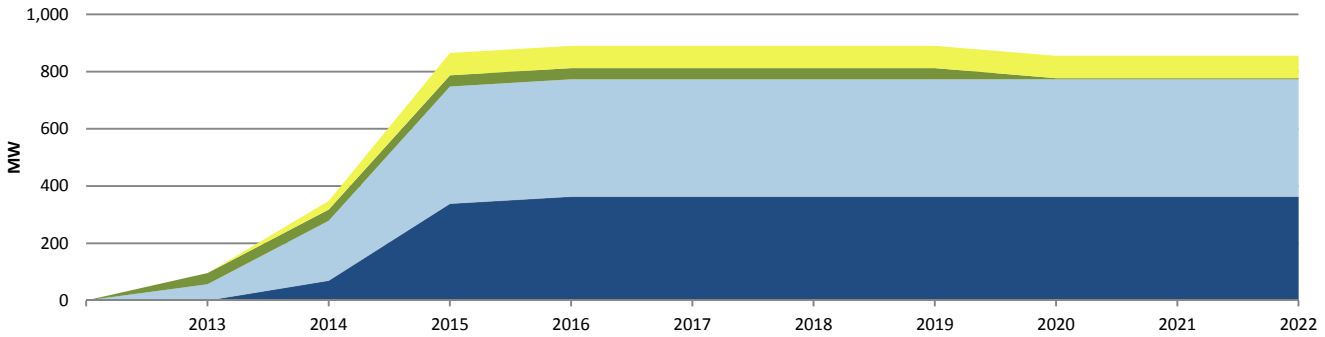
Fourteen percent of the installed wind capacity is assumed to be available at the time of summer peak, and 32 percent is assumed to be available at the time of winter peak. Monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values (percent of installed capacity) are determined by picking the lower value between the actual historic median wind generator contribution and the simulated 10-year wind historic median contribution at the top five contiguous demand hours of the day for each winter and summer season, or shoulder period month. The process of picking the lower value between actual historic wind data and the simulated 10-year historic wind data will continue until 10 years of actual wind data is accumulated, at which point the simulated wind data will be phased out of the WCC calculation. The WCC values are updated annually.

Ontario's solar capacity value is forecast to be 30 percent of installed for the summer peak and 4 percent contribution for the winter peak. The difference is due to the fact that the summer peak occurs in the afternoon, whereas the winter peak occurs in the evening around dinner time. The values are based on historical modeled photovoltaic output data at the time of summer and winter peaks. The renewable capacity outlook is included in below (NPCC-Ontario-Table 5, NPCC-Ontario-Figure 3, and NPCC-Ontario-Table 6).

NPCC-Ontario-Table 5: Renewable Capacity Outlook[229]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-Ontario-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	5,794	94.1%	6,157	87.8%	363	6,500	74.0%	706
Pumped Storage	91	1.5%	91	1.3%	0	91	1.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	227	3.7%	637	9.1%	410	1,429	16.3%	1,202
Biomass	43	0.7%	47	0.7%	4	204	2.3%	161
Solar	0	0.0%	78	1.1%	78	558	6.4%	558
TOTAL	**6,156**	**100.0%**	**7,011**	**100.0%**	**855**	**8,782**	**100.0%**	**2,627**

NPCC-Ontario-Figure3: Renewable Capacity Outlook



On average, the assumed capacity contribution for biomass generation ranges from 64 to 98 percent of installed capacity. Hydro-electric generation output forecast is based on median historical values of hydro-electric production and contribution to operating reserve during weekday peak demand hours. Through this method, routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data. Market data starting from May 2002 is used, with new values calculated annually as additional years of market experience are acquired. The assumed capacity contributions for hydroelectric is 71 percent in the summer and 75 percent for the winter.

The hydro-electric forecast may be adjusted to account for the impact of project-related long-duration outages that occur less frequently than regular maintenance. The hydro-electric performance is monitored on a monthly basis, and adjustments may also be made to the forecast values when water conditions drive expectations of higher or lower output that deviates from median values by approximately 500 MW for two consecutive months. The project-related long-duration outages may include hydro facility expansions and major equipment replacements and/or repairs.

NPCC-Ontario-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed[230]

	Current				2022 Planned			
NPCC-Ontario-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	1,725	0	7,832	47	4,651	260	8,347	49
On-Peak Derate	1,498	0	2,038	4	4,014	182	2,190	2
EXPECTED ON-PEAK OUTPUT	227	0	5,794	43	637	78	6,157	47

[229] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[230] Note: The table above shows only the expected grid-connected renewable generation resources in Ontario. A substantial amount of renewable generation is embedded and is included in the demand forecast. About 9 percent of wind, 28 percent of biomass and 81 percent of solar are expected to be embedded in the distribution networks.

Centralized forecasting for variable resources such as solar and wind is an initiative designed to allow for better forecasting of energy production to ensure a more accurate unit commitment occurs. A centralized forecast is being developed for all grid-connected variable resources with a full implementation set to be complete by the first quarter of 2013. Forecasting for embedded variable resources will be developed in 2013. Additionally, the IESO's Renewable Integration Initiative (RII) will facilitate the dispatching of renewable energy, with implementation expected in the fourth quarter of 2013. Variable generation dispatch will allow for greater flexibility and help alleviate occurrences of surplus base-load generation.

Capacity Transactions

No Firm imports into Ontario, exports to other Regions or emergency generation are considered in this *2012LTRA* Reference case. However, for use during daily operation, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC, and MRO include contractual provisions for emergency imports directly by the IESO. IESO also participates in a shared activation of reserve group, which includes PJM, NYISO, ISO-NE, and New Brunswick.

Transmission

A new 110 mile 500 kV double-circuit line from the Bruce Power complex to Milton Switching Station (SS) was officially declared in service in June 2012. This new line was built to accommodate the output of all eight generating units at the Bruce complex together with approximately 500 MW of existing wind generating capacity, as well as a further 1,200 MW of new renewable generating capacity that is forecast for development within the area. With the new generating facilities, the combined generation in the Bruce Area is projected to exceed 8,100 MW. New dynamic voltage control facilities at Nanticoke and Detweiler will improve the transfer capability from the Bruce Area. A summary of existing and projected transmission is included below (NPCC-Ontario-Table 7).

NPCC-Ontario-Table 7: Existing and Projected Transmission

NPCC-Ontario	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	17,931	0	17,931
Currently Under Construction	93	0	93
Planned - Completed within First Five Years	0	0	0
Planned - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	18,024	0	18,024
Conceptual - Completed within First Five Years	180	0	180
Conceptual - Completed within Second Five Years	283	0	283
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**18,487**	**0**	**18,487**

The existing Bruce SPS will be enhanced not only to accommodate the two new 500 kV circuits between the Bruce complex and Milton SS, but also to address other contingency conditions not previously covered by the SPS. The intent of the expanded coverage is to limit the extent of restrictions imposed on the output from the Bruce units during transmission element outage conditions while also assisting with the re-preparation of the system following a permanent fault when subsequent contingency conditions may become more critical. This SPS will be a permanent feature to deal with planned outages and is not intended for normal operations or to avoid or delay the construction of bulk transmission facilities. The enhanced system was approved by NPCC in spring of 2012 and was placed in service in the second quarter.

To coincide with the completion of the new Bruce to Milton 500 kV line, a 350 Mvar SVC was installed at Nanticoke SS, connected to the 500 kV busbar, and another 350 Mvar SVC was installed at Detweiler TS, connected to the 230 kV busbar. These SVCs were required to provide dynamic reactive support following a critical double-circuit contingency involving either of the 500 kV lines between the Bruce complex and Milton SS.

Four phase angle regulators (PARs) are now operational and regulating flow over the Ontario-Michigan interconnections. The operation of these PARs helps control inter-jurisdictional loop flows and assists in the management of system congestion.

The transmission lines east of Mississagi TS and the north-south corridor have experienced increased congestion due to the continuing addition of new renewable resources and reduced demand. It is expected that congestion will further increase with projects in the area, both proposed and under construction becoming operational. To help incorporate the future

Lower Mattagami expansion projects and other renewable generation resources and to reduce likelihood of congestion, Hydro One installed series compensation on the 500 kV north-south lines at Nobel SS and dynamic reactive compensation facilities at Porcupine TS. To further improve the north-south transfer capability, Hydro One will install static reactive compensation facilities at Porcupine TS, Pinard TS, and Hanmer TS and dynamic reactive compensation facilities at Kirkland Lake TS. All the static and dynamic compensation facilities are going in service gradually, with the last one scheduled for 2013.

The Government of Ontario's Long-Term Energy Plan (LTEP) specifies five priority transmission projects to accommodate renewable generation to serve new load and support reliability. Furthermore, in a Supply Mix Directive on February 17, 2011, the OPA was required to include the five priority projects as part of long-term planning:

- Devices to enhance transfer capability, such as series or static var compensation, or other similar devices, in southwestern Ontario
- Enhance the East-West Tie along the east shore of Lake Superior through a new line
- Upgrade existing lines west of London
- A new line west of London
- New line to Pickle Lake

Northwestern Ontario (northwest) is connected to the rest of the province by the double circuit 230 kV East-West Tie. The Region has significant amounts of hydro-electric generation as well as other resources such as coal, gas, and biomass. As part of the coal shutdown, Atikokan and Thunder Bay (totaling 500 MW of generation capacity) will cease coal-fired operation by 2014. To maintain supply security in this area under the wide range of possible system and water conditions, additional resources located in the northwest or increased westbound transfer capability into this Region through the East-West Tie are required. The conversion of Atikokan to biomass and Thunder Bay to gas operation, as indicated in the LTEP, is part of the solution. The expansion of the East-West Tie is to provide a long-term reliable and cost-effective supply to the northwest. The line is anticipated to be in service no sooner than 2017.

A new supply line to Pickle Lake is currently being planned as part of a potential suite of options that may be required to serve growing load and maintain reliability in the system north of Dryden. Load in and north of this area is forecast to grow substantially over the next 10 to 15 years, and it is expected that new supply to the area will be required around 2015. Various options, both 230 kV and 115 kV are being studied, with lengths up to 300 km. These options will have some capability to support growth in the Red Lake Area to provide operational flexibility to enable refurbishment of end-of-life equipment, and to serve new load for mining operations in the area known as the Ring of Fire. The Ring of Fire Area is approximately 350 km northeast of Pickle Lake. If the new supply line to Pickle Lake is delayed, load that is being planned for connection after 2015 will not be able to connect until the new line is available. Studies have identified the need for incremental reactive capability throughout the region north of Dryden to support load growth, and there may also be the need for reactive devices at strategic locations in the bulk system at and west of Mackenzie TS.

The LTEP includes three transmission projects to accommodate additional renewable generation in southwestern Ontario: two upgrade projects and one new transmission line project. The two upgrade projects consist of a reactive compensation project and a line re-conductoring project. For the reactive compensation project, the OPA has recommended installation of an SVC with a capacitive capacity of 350 Mvar and connecting to the 500kV voltage level at the Milton Station. An in-service date of spring 2015 has been established for this project. The planned line re-conductoring project will consist of re-conductoring approximately 70 km of 230 kV transmission line between Lambton TS and Longwood TS. The two upgrade projects are intended to maximize the capability of the existing system and increase capability to incorporate additional renewable resources in a shorter time frame than a new transmission line can be built. A new transmission line west of London is targeted to be completed in 2017.

Ontario will monitor the progress of the continued operation of nuclear units at Pickering Nuclear Generating System. Pickering Nuclear Generating System units connect directly to the 230 kV system at Cherrywood TS, east of the Greater Toronto Area. The retirement of Pickering Nuclear Generating Station would require an additional 230 kV supply source for the Pickering and Oshawa Areas. Plans are currently being developed for construction of the Clarington 500/230 kV Transformer Station by as early as 2015.

As demand increases in the western part of the Greater Toronto Area, the loading on the 500/230 kV transformers at Claireville TS and Trafalgar TS will exceed their capacity by about the middle of this decade. An additional 500 to 230 kV supply source would be required to relieve the loading on the existing autotransformers. Installation of 500/230 kV transformers later in this decade at the 500 kV Milton Switching Station is one of the options under consideration.

The transmission projects that are under various stages of construction and the planned projects will address the transmission constraints identified. The transmitters in Ontario together with the OPA proactively plan the transmission network in order to ensure timely system adjustments, upgrades, and expansions. Delays to the in-service dates of bulk transmission projects resulting from delays in obtaining required approvals or delays in construction may result in increased congestion or Special Protection Systems (post-contingency generation rejection) in the interim.

System reinforcements are also being considered in a number of regional areas throughout the province, such as Kitchener-Waterloo-Cambridge-Guelph, York Region, and Ottawa, in order to maintain a reliable local supply of electricity. The OPA's regional planning approach addresses project delays. Regional planning develops options for each need, in a coordinated manner, guided by principles that maintain a long-term view that anticipates uncertainties and maintains flexibility. Conservation, supply, and transmission plans are coordinated to deliver the solutions that are required for each locale.

Vulnerability Assessment

As described in section 5, hydro-electric generation capacity contributions are based on median historical values of hydro-electric production plus operating reserve provided during weekday peak demand hours. Hydro-electric production is monitored on a monthly basis, and due allowance is made for deviations from the median historical conditions.

Units at Bruce B and Darlington Nuclear Generating Stations are expected to reach the end of their service lives in the latter half of the 10-year period. To extend the life of these units, they will have to be taken out of service sequentially for about three years for refurbishment. A number of options are being considered, and the timing of the refurbishment plan is not yet finalized.

The Government of Ontario in its Long-Term Energy Plan (LTEP) specified the target for large-scale development of renewable energy projects and implementation of conservation. The renewable resources target for wind, solar, and bioenergy is 10,700 MW by 2018, accommodated through transmission expansion and maximizing the use of the existing system. Ontario will grow its clean energy portfolio through the continuation of programs like the Feed-in Tariff (FIT) and microFIT.

Ontario will continue to grow its hydro-electric capacity, with a target of 9,000 MW by 2018. This will be achieved through the development of new facilities and through significant investments to maximize the use of Ontario's existing facilities.

The IESO includes a quantity of Demand Response termed the "Reliably Available Capacity" in its reliability analysis. This does not represent the total registered capacity of Demand Response programs. For market-based programs, the IESO utilizes historical information to ascertain the amount of Demand Response capacity that is typically bid into the market at the time of the weekly peak demand. For programs that have contracts, the IESO uses both historical information and contract information in order to determine the quantity of Reliably Available Capacity.

Over the assessment time frame, the level of renewables penetration is expected to increase through the FIT and microFIT programs. As a result, there will be significant increases in generation connected to the distribution systems, as well as

additions to the IESO-controlled grid. Most of this generation will be variable in nature, which adds more volatility as on-grid demand is impacted both by underlying demand and by variable generation within the distribution system.

As a result of the increase in the level of penetration of variable generation combined with the return of two units at Bruce Nuclear Generating Station, occurrences of surplus base-load generation will continue until the middle of the decade. An increasing number of mitigation options to reduce surplus will need to be utilized. Surplus base-load conditions are expected to significantly reduce when the nuclear refurbishment programs begin.

There are a number of initiatives (such as centralized forecasting and dispatch of renewable generation) being implemented, as described in section 5, to mitigate the challenges posed by variable generation and distributed generation.

There are no wide-area UVLS programs in Ontario, and there are no plans to install any UVLS schemes in the future.

The majority of the Special Protection Systems that are in use within Ontario are intended to address the effects of contingencies under outage conditions and are not intended to avoid or delay the construction of bulk transmission facilities. The principal exception is the northeast load and generation rejection SPS that mitigates the effects of contingencies involving the single-circuit 500 kV lines that service this area. This SPS is designed to achieve a post-contingency match between the load and available generation in the area to prevent possible separation and islanding of a portion of the north-east system.

Following the 1998 ice storm and prior to the 2002 opening of Ontario's competitive markets for electricity, Ontario's Emergency Planning Task Force (EPTF) was created. It is chaired by the IESO and comprises the major electricity sector players including the provincial government's Ministry of Energy. The EPTF oversees an emergency management team called the Crisis Management Support Team (CMST) to manage any crisis and mitigate the impact on public health and safety due to an extended electricity system emergency. Ontario runs an annual program of Reliability and Emergency Management workshops, including tabletop drills. Additionally, major integrated exercises are staged in which both the operational response and emergency management processes are activated. The CMST also performs regular test activations.

During the nine-day capacity and energy emergency that followed the August 2003 blackout, the CMST managed the emergency via 31 conference calls and was instrumental in producing media messages, facilitating the government's appeal and direction for reduced demand, and obtaining the necessary environmental variances to secure additional supply.

The IESO has advanced the development of an on-line limit derivation tool to maximize transmission capability in the operating time frame. Currently, this tool is used to calculate a limited set of operating security limits in southern Ontario, in the northeast and the east. There are plans to extend the use of this tool to the entire province by the end of 2013. The limits calculated by the tool are used to plan and schedule outages and to re-prepare the power system following a forced outage.

A web-based online outage requests tool was introduced last fall for market participants to submit their outages directly into the Integrated Outage Management System. The new tool replaces a manual process and is a marked improvement in efficiency, with validation and alerts for short notice requests built into the online tool.

As of March 2012, 4.7 million smart meters have been installed across the province, and 70 local distribution companies and 4.36 million meters were enrolled with the Meter Data Management and Repository (MDM/R). The MDM/R system actively processes smart meter data and produces time of use (TOU) billing quantities for customer invoices. The smart meter customers are charged TOU rates, where the price of electricity depends on when it is used relative to peak demand periods.

The IESO reviews all relay protection misoperations and works with Transmission Operators to ensure that timely assessments and repairs are completed for reliable operation of the IESO-controlled grid.

Over the last two years, about 3,000 MW of coal-fired generation from six coal units at two generating stations has been shutdown. The current installed capacity of coal-fired generation in Ontario amounts to about 3,500 MW. The phase-out of the remaining coal-fired generation by the end of 2014 is underway. In the intervening period, the Ontario government has implemented greenhouse gas emissions targets for coal-powered generation to ensure that between 2012 and 2014, annual emissions are two-thirds lower than 2003 levels.

Ontario Power Generation, the owner of the coal units, is making significant reductions in CO_2 emissions from coal in a manner consistent with government direction. OPG's strategy will achieve the required reductions in emissions while making sure the coal units are available to meet peak electricity demand.

As described in section 5, a number of nuclear units at Darlington and Bruce B Nuclear Generating Stations will be on refurbishment outage at different times over the assessment period. At this stage, these outages are not expected to have any reliability issues as plans are in place—these plans are reviewed on an ongoing basis with changes in assumptions.

Retrofits are required for conversion from coal to other fuels such as gas or biomass. The plans allow sufficient time for conversions.

Standing and Emerging Reliability Issues

Demand Forecasting Models

Maintaining accuracy of demand forecasting models is an emerging issue. Demand forecasting continues to evolve and is becoming more complex due to a number of driving factors. Conservation has had a significant impact on demand and continues to make it difficult for system planners and operators to capture or estimate the impact of conservation programs and initiatives. Similarly, embedded generation is starting to require more attention from load forecasters as the amount of embedded generation capacity is expected to show a dramatic increase. The fact that much of the embedded generation will be variable in nature adds a new degree of volatility as on-grid demand is impacted both by underlying demand and by variable generation within the distribution system. The correlation of end-use consumption uncertainty with distributed generation uncertainty is not a trivial modeling exercise. Lastly, the evolution of the smart grid and smart grid technologies will unlock greater Demand Response and increase the complexity of operating the electricity grid.

The issue requires industry attention over the next 10 years. The consequence of variance in demand forecasting will be moderated as the industry develops the means and processes to track and evaluate the individual programs' performance. Improved data collection and new models and tools will enable the industry to more accurately identify and assess the impact of these initiatives on the power system.

Asset Renewal - A Systematic Approach for Continuous Modernization of Aging Energy Infrastructure

Asset renewal is a standing issue. Much of the current power system infrastructure, whether generation, transmission, or distribution equipment, is aging and needs to be refurbished, replaced, or upgraded to comply with new standards and to meet demand. A long-term plan is required to coordinate the renewal of infrastructure to manage reliability, environmental, and cost impact.

In the latter half of the 10-year period, a number of nuclear units at Bruce and Darlington Nuclear Generating Stations will be expected to undergo refurbishment. The Pickering Nuclear Generating Station is scheduled for retirement within the next decade. Coal units will cease burning coal by 2014, with conversion to other fuels being considered as just one of several mitigating options. Some transmission and distribution components are over 80 years old and require upgrading. Although many companies have sustainment programs in place for asset renewal, the overall scope of the problem is what presents the challenge. Moreover, challenges can be expected in the coordination between parties and the competition for resources from other major non-electrical infrastructure developments.

NPCC-Québec

Planning Reserve Margins

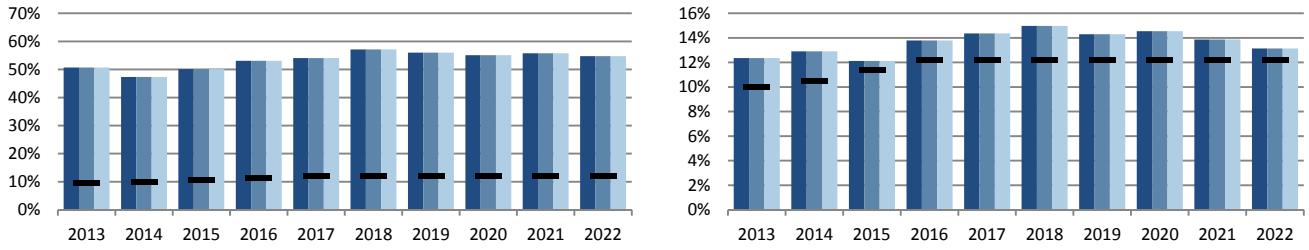
The Québec Area is projecting adequate Planning Reserve Margins throughout the long-term assessment period, varying between 12.1 and 15 percent. For the first year considered in this assessment, the 2013/2014 winter peak, the Anticipated Reserve Margin is 12.36 percent, which is above the NERC Reference Reserve Margin of 10 percent. Québec's Anticipated Reserve Margin for the 2012/2013 winter is projected to be 10.8 percent, also above the NERC Reference Margin Level 9.6 percent.[231] The NERC Reference Reserve Margin Levels are drawn from the most recent Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on November 29, 2011. These levels vary between 9.6 and 12.2 percent during the 10-year assessment (NPCC-Québec-Table 1 and NPCC-Québec-Figure 1).

NPCC-Québec-Table 1: Planning Reserve Margins[232]

NPCC-Québec-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		50.71%	47.36%	50.12%	53.11%	54.08%	57.13%	56.00%	55.11%	55.79%	54.73%
PROSPECTIVE		50.71%	47.36%	50.12%	53.11%	54.08%	57.13%	56.00%	55.11%	55.79%	54.73%
ADJUSTED POTENTIAL		50.71%	47.36%	50.12%	53.11%	54.08%	57.13%	56.00%	55.11%	55.79%	54.73%
NERC REFERENCE	-	**9.60%**	**10.00%**	**10.50%**	**11.40%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**

NPCC-Québec-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		12.36%	12.90%	12.12%	13.79%	14.36%	14.97%	14.30%	14.54%	13.86%	13.14%
PROSPECTIVE		12.36%	12.90%	12.12%	13.79%	14.36%	14.97%	14.30%	14.54%	13.86%	13.14%
ADJUSTED POTENTIAL		12.36%	12.90%	12.12%	13.79%	14.36%	14.97%	14.30%	14.54%	13.86%	13.14%
NERC REFERENCE	-	**10.00%**	**10.50%**	**11.40%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**

NPCC-Québec-Figure 1: Summer (Left) and Winter[233] (Right) Planning Reserve Margins



The Planning Reserve Margins projected in this assessment are adequate and result mostly from the commissioning of additional resources, most of which are new hydro projects, such as La Sarcelle Generating Station, the Romaine River Complex (Romaine 1, 2, 3, and 4), additional capacity at Sainte-Margerite-3 Generating Station, and wind and biomass resources. Moreover, an additional amount of Demand Response programs contributes to this adequate level of projected reserve margins.

For this assessment, the Gentilly-2 nuclear station will be out of service for decommissioning at the end of 2012. The Tracy and La Citière thermal generating stations have also been permanently retired.

Demand

The compound annual growth rate (CAGR) forecast for Total Internal Demand is 0.79 percent during the next 10 years (2013/2014 – 2022/2023 winter seasons), which is slightly lower than the one percent growth rate forecast reported in the 2011 LTRA (NPCC-Québec-Table 2). As for the Net Energy for Load (NEL), the average growth rate forecast is also 0.8 percent, compared to a 0.6 percent growth rate forecasted last year.

[231] Additional information on the 2012/2013 winter season can be found in the NERC *Winter Reliability Assessment*: http://www.nerc.com/page.php?cid=4|61.
[232] Winter years represent the first year of the winter season (For example, the 2013 column represents the 2013/2014 winter season).
[233] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

NPCC-Québec-Table 2: Demand Outlook

NPCC-Québec-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	21,115	22,818	1,704	8.1%	0.87%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**21,115**	**22,818**	**1,704**	**8.1%**	**0.87%**

NPCC-Québec-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	37,810	40,575	2,766	7.3%	0.79%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**37,810**	**40,575**	**2,766**	**7.3%**	**0.79%**

The Net Internal Demand for the 2013/2014 winter peak peak is projected to be 37,810 MW, which is 267 MW higher than the forecasted 2012/2013 winter peak demand. The demand forecast methods used in this assessment have not changed from previous years. Additionally, there have been no footprint changes and no entity acquisitions or exits.

Demand-Side Management

The only Demand Response programs in the Québec Area specifically designed for peak-load reduction during winter operating periods are interruptible demand programs (for large industrial customers) totaling 1,660 MW for the 2013/2014 winter period, decreasing to 1,300 MW by the final year of the assessment (NPCC-Québec-Table 3). It is usually used in situations when load is expected to reach high levels or when resources are not expected to be sufficient to meet load at peak periods. Demand Response is relatively stable over the assessment period, with a maximum reached for the 2013/2014 winter peak period.

NPCC-Québec-Table 3: Projected Demand-Side Management

	Short-Term					
NPCC-Québec-Winter	2013/14	2014/15	2015/16	2022/23	10-Year Change	2022/23 Share of Total Internal Demand
Direct Control Load Management (DCLM)	250	250	250	250	0	0.62%
Contractually Interruptible (Curtailable)	1,660	1,439	1,439	1,300	-360	3.20%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	1,910	1,689	1,689	1,550	-360	3.82%
TOTAL ENERGY EFFICIENCY	1,980	2,150	2,300	3,190	1,210	7.86%
TOTAL DEMAND-SIDE MANAGEMENT	**3,890**	**3,839**	**3,989**	**4,740**	**850**	**11.68%**

Total Energy Efficiency/Conservation is included in the forecast load and accounts for 1,980 MW at the 2013/2014 winter peak period. Energy Efficiency is growing throughout the entire period of the assessment. The total on-peak Demand Response and Energy Efficiency/Conservation for the 2022/2023 winter period is projected to be approximately 4,740 MW.

On a yearly basis, Hydro-Québec Distribution presents its Energy Efficiency Plan Update, "Plan global en efficacité énergétique," to the Québec Energy Board (regulatory body in Québec) for the next and upcoming years. This plan focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers. Examples of programs and tools for promoting energy savings for the residential customers include old refrigerator recycling, electronic thermostats, low-energy lighting, etc. The provincial government, through its Ministry of Natural Resources, also implements Energy Efficiency/Conservation programs, mainly in the area of building standards and housing insulation.

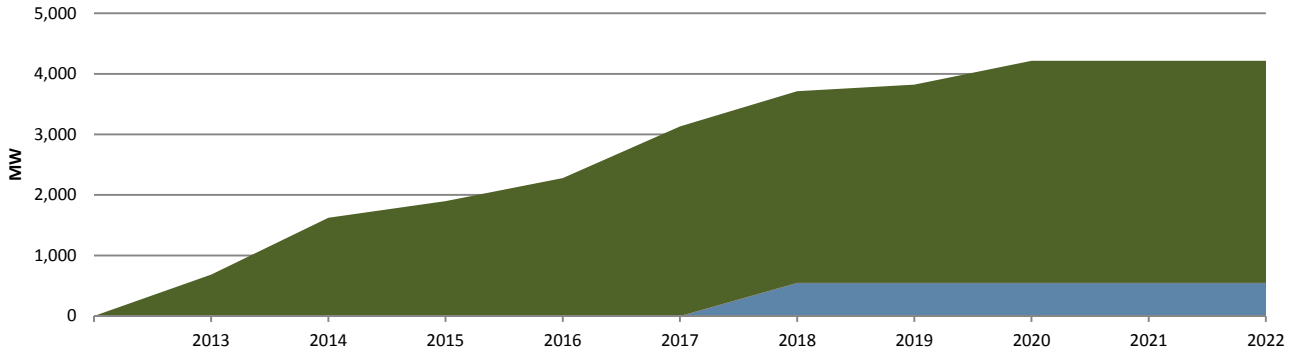
Generation

At the time of this assessment, available resources for the next winter in the Québec Area are evaluated at 39,502 MW, most of which are hydropower generation (97 percent). Wind and biomass resources, which are owned and operated by Independent Power Producers (IPPs) and under long-term power purchase agreements with Hydro-Québec Distribution and Hydro-Québec Production, account for two percent of the available capacity. Hydro-Québec Production also operates one fuel oil generating station (for peaking purposes), which represents about one percent of the total available capacity (NPCC-Québec-Table 4 and NPCC-Québec-Figure 2).

NPCC-Québec-Table 4: Capacity Outlook[234]

NPCC-Québec-Winter	Current		2022/23 Planned			2022/23 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	0	0.0%	0	0.0%	0	0	0.0%	0
Petroleum	436	1.1%	436	1.0%	0	436	1.0%	0
Gas	0	0.0%	547	1.3%	547	547	1.3%	547
Nuclear	0	0.0%	0	0.0%	0	0	0.0%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	39,066	98.9%	42,418	97.7%	3,353	42,418	97.7%	3,353
TOTAL	**39,502**	**100.0%**	**43,401**	**100.0%**	**3,900**	**43,401**	**100.0%**	**3,900**

NPCC-Québec-Figure 2: Winter Net Capacity Change[235]



The Existing-Certain capacity increased by an amount of 1,240 MW since the previous assessment, of which 720 MW are from hydropower generation and 520 MW from wind and biomass.

TransCanada Energy's 547MW natural gas combined-cycle generating station in Bécancour is mothballed and accounts for the total Existing-Inoperable resources. Each summer, Hydro-Québec Distribution must decide whether to mothball the Bécancour power plant for an additional year or to re-start it for the coming year. Although this plant is expected to be mothballed until December 2017, it could be re-started sooner if needed.

As mentioned above, the Gentilly 2 nuclear station (675 MW) will be out of service for decommissioning at the end of 2012. Two thermal generating stations have also been permanently retired since the last assessment—Tracy (450 MW) and La Citière (280 MW). In the previous assessment, the Tracy power plant was mothballed over the entire assessment period.

The temporary unit shutdown and retirements described above are offset by the commissioning of new resources. The last two units of La Sarcelle Hydro Generating Station (50 MW each) are to be commissioned during the 2012/2013 winter period. The Romaine-2 (622 MW) and Romaine-1 (260 MW) Hydro Generating Station are under construction and are expected to be commissioned for the 2014/2015 and 2016/2017 winter peak periods respectively. The added capacity at Sainte-Margerite-3 is expected to be commissioned for the 2017/2018 winter peak period, adding 440 MW of capacity. Two other generating stations at the Romaine Complex (Romaine-3 and Romaine-4) are expected to be commissioned later during the assessment period (2017/2018 and 2020/2021), adding 668 MW of capacity to the system. Finally, existing power plant retrofitting will add close to 500 MW of new capacity by the 2020/2021 winter peak period.

In recent years, Hydro-Québec Distribution has launched several calls for tenders and electricity purchase programs for new renewable supplies, which will also be commissioned in the next years:

- 2,290 MW of wind power to be commissioned between 2012 and 2015.

[234] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[235] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

- 125 MW generated by small hydro plants (50 MW and less) developed in partnership with local and First Nations communities, will be commissioned between 2012 and 2014.
- 300 MW generated from biomass to be commissioned between 2012 and 2016.

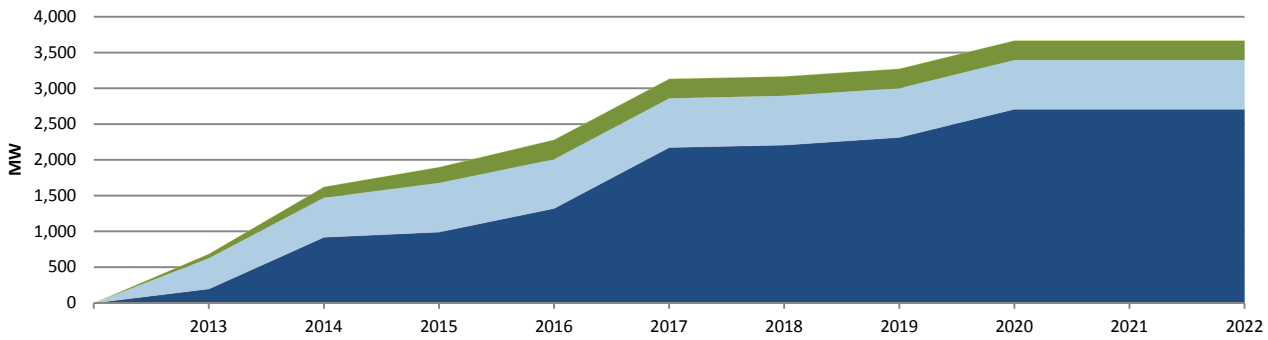
As for behind-the-meter generation, it is negligible and is included in the load forecast. For hydro resources, maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours, while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Biomass and wind resources are owned by Independent Power Producers (IPPs). These IPPs have signed contractual agreements with Hydro-Québec. Therefore, for biomass resources, maximum capacity and expected on-peak capacity are equal to contractual capacity, representing almost 100 percent of nameplate capacity. For wind resources, capacity contribution at peak is estimated at 30 percent of contractual capacity, which represents 490 MW and 973 MW respectively for the 2012/2013 (current) and 2022/2023 winter periods. The maximum wind capacity is equal to contractual capacity, which generally equals to its nameplate capacity. For summer peak periods, the expected on-peak wind capacity is set to zero as wind resources are completely derated (NPCC-Québec-Table 5 and NPCC-Québec-Figure 3).

NPCC-Québec-Table 5: Renewable Capacity Outlook[236]

	Current		2022/23 Planned			2022/23 Planned & Conceptual		
NPCC-Québec-Winter	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	38,315	98.1%	40,971	96.6%	2,656	40,971	96.6%	2,656
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	490	1.3%	973	2.3%	483	973	2.3%	483
Biomass	261	0.7%	474	1.1%	213	474	1.1%	213
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**39,066**	**100.0%**	**42,418**	**100.0%**	**3,353**	**42,418**	**100.0%**	**3,353**

NPCC-Québec-Figure 3: Winter Net Renewable Capacity Change[237]



Wind generation integration has not significantly impacted day-to-day operation of the system, and the actual level of wind generation does not require particular operating procedures. However, with the increasing amount of wind in the system, the foreseeable impact on system management may show up, and the following are under study:

- Wind generation variability on system load and interconnection ramping.
- Frequency and voltage regulation problems.
- Increase of start-ups/shutdowns of hydroelectric units due to load following coupled with wind variability; efficiency losses in generating units also expected.
- Reduction of low-load operation flexibility due to low inertial response of wind generation coupled to must-run hydroelectric generation.

[236] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[237] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

Capacity Transactions

Expected capacity purchases are planned by Hydro-Québec Distribution as needed for the Québec internal demand. These purchases are set at 1,100 MW throughout the assessment period and may be supplied by resources located in Québec or in neighboring markets. In this regard, Hydro-Québec Distribution has designated the Massena–Châteauguay (1,000 MW) and Dennison–Langlois (100 MW) interconnections' transfer capacity to meet its resource requirements during winter peak periods. These purchases are not backed by firm long-term contracts. However, on a yearly basis, Hydro-Québec Distribution proceeds with short-term capacity purchases (UCAP) in order to meet its capacity requirements if needed.

The Québec Area will support firm capacity sales totaling 398 MW to New England and Ontario (Cornwall) during the 2013/2014 winter peak, backed by Firm contracts for both generation and transmission, but which will decline to 145 MW in 2020 (NPCC-Québec-Table 7). Moreover, 228 MW of Firm exports for the 2014/2015 winter period and 500 MW for the 2015/2016 winter peak are committed for neighboring area's needs.

NPCC-Québec-Table 7: Projected Capacity Transactions

NPCC-Québec-Winter	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Firm Imports	0	0	0	0	0	0	0	0	0	0
TOTAL IMPORTS	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	398	626	676	151	151	151	151	145	145	145
TOTAL EXPORTS	398	626	676	151	151	151	151	145	145	145
TOTAL NET CAPACITY TRANSACTIONS	**702**	**474**	**424**	**949**	**949**	**949**	**949**	**955**	**955**	**955**

The Québec Area does not rely on any emergency capacity imports to meet its Reserve Margin Reference Level.

Transmission

This section briefly describes the BPS transmission additions anticipated to be in service during the assessment period. A summary of existing and projected additions is included below (NPCC-Québec-Table 8). Descriptions for each project of particular importance are also included below.

NPCC-Québec-Table 8: Existing and Projected Transmission

NPCC-Québec	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	21,273	1,514	22,787
Currently Under Construction	412	0	412
Planned - Completed within First Five Years	68	0	68
Planned - Completed within Second Five Years	129	0	129
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	21,881	1,514	23,395
Conceptual - Completed within First Five Years	452	93	546
Conceptual - Completed within Second Five Years	599	0	599
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**22,932**	**1,607**	**24,539**

The Romaine River Hydro Complex Integration

Construction of the first phase of transmission infrastructures for the Romaine River Hydro Complex project has now begun. The generating stations will be integrated on a 735 kV infrastructure initially operated at 315 kV. Romaine-2 and Romaine-1 will be integrated in 2014/2016 at Arnaud 735/315 kV substation. Romaine-3 and Romaine-4 will be integrated in 2017/2020 at Montagnais 735/315 kV substation.

Main system upgrades for this project require construction for 2014 of a new 735 kV switching station to be named "Aux Outardes," located between the existing Micoua and Manicouagan Transformer Stations. Two 735 kV lines will be redirected into the new station and one new 735 kV line (3 miles) will be built between Aux Outardes and Micoua.

The Bout-de-l'Île 735-kV Section

Hydro-Québec TransÉnergie is adding a new 735 kV section at Bout-de-l'Île (east end of Montréal Island) substation. This was originally a 315/120 kV station. The Boucherville–Duvernay 735 kV line (line 7009), which passes by Bout-de-l'Île, will be looped into the new station. A new -300/+300 Mvar Static Var Compensator will be integrated into the 735-kV section in 2013.

The project also includes the addition of two 735/315 kV, 1,650 MVA transformers in 2014. This new 735 kV source will allow redistribution of load around the Greater Montréal Area and will absorb load growth in the eastern part of Montréal. This project will enable future major modifications to the Montréal Area regional subsystem. Many of the present 120 kV distribution stations will be rebuilt into 315 kV stations, and the Montréal regional network will be converted to 315 kV.

The Northern Pass Project

This project to increase interconnection transfer capability between Québec and New England by 1,200 MW is now being studied. The project involves construction of a ±300 kV dc transmission line about 46 miles long from Des Cantons 735/230 kV substation to the Canadian-U.S. border. This line will be extended into the United States to a substation built in Franklin, New Hampshire.

The project in Québec also includes the construction of two 600 MW converters at Des Cantons and a 300 kV dc switchyard. Permitting for this project is presently ongoing but the initial commissioning date of 2015 may be delayed.

Wind Generation Integration Projects

A number of wind transmission projects with voltages ranging from 120 kV to 315 kV are either under construction or in planning stages in order to integrate wind generation planned to come on-line in the next few years. These wind generation projects are distributed in many areas of the Province of Québec, but most are near the shores of the Gaspésie Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

Projects on the main system include 735 kV series compensation additions, and the addition of a second SVC at Bout-de-l'Île substation after the addition of the previously mentioned 735 kV section, and an SVC at Jacques-Cartier substation. Nominal current upgrades will also be done on some existing series compensation, and a thermal capacity upgrade will be done on two 735 kV lines. However, the future construction of the Chamouchouane–Bout-de-l'Île 735 kV line (see below) will replace a number of the above-mentioned projects.

Chamouchouane – Bout-de-l'Île 735 kV Line

The large generation additions and transmission services coming up over the next years require, as shown above, a number of system additions to maintain reliability. Moreover, planning studies have shown that to optimize the different solutions and to significantly reduce marginal losses on the system due to this new generation, a new 735 kV line from Chamouchouane substation on the eastern James Bay subsystem to Bout-de-l'Île substation in Montréal (about 230 miles) is required. Planning, permitting and construction delays are such that the line is scheduled for the 2017/2018 winter peak period. This optimization will result in replacing some of the above-mentioned projects, and in other cases will result in reducing additional equipment that was previously planned. The new line will also reduce transfers on other parallel lines on the Manicouagan–Québec 735 kV interface, thus optimizing operation flexibility and reducing losses.

Public information meetings have begun on this project. Final line route has not been determined yet and government authorization processes are ongoing.

Other 735 kV Conceptual Projects

A new 735/315 kV transformer station near the existing Arnaud 735 kV station is being projected for 2018. This station, tentatively named Arnaud-2, will be about 9.3 miles from Arnaud. It will be integrated into the Churchill Falls–Manicouagan subsystem using two existing lines and one new 15-km (9.3 mi.) 735 kV line from Arnaud Station. Two 735/315 kV, 1650 MVA transformers and six 315 kV line feeders will complete the station. Two double-circuit 315 kV lines will eventually feed the Alouette Aluminum Smelter Complex, replacing the 161 kV feeders now in service.

A new 735/315 kV transformer station is being projected near the existing Lebel 315/120 kV station in the Abitibi region of the system. This will consolidate the Abitibi subsystem, which presently has a 120 kV infrastructure with a 315 kV feed at Lebel and Figuery substations. A new 142 km (88 miles) 735 kV line is projected from Abitibi 735 kV Station on the James

Bay system to feed this new station. Two 735/315 kV, 1650 MVA transformers and four 315 kV line feeders will complete the station. It is projected to be in service in fall 2018.

Regional Projects Under Construction

There are a number of regional projects now underway. The three most important are listed here:

- Limoilou 230/25 kV substation in Québec City; in service fall 2012
- St-Bruno 315/25 kV substation south of Montréal; in service fall 2013
- Bécancour 230 and 120 kV system reinforcement; Bécancour Industrial Park, in service fall 2012

Upcoming Regional Projects

Other regional substation and/or line projects are now in the planning/permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City Areas and another dozen in other areas within service dates from 2012 to 2018.

Planning studies leading to system enhancement projects such as those mentioned above ensure that there will be no long-term transmission constraints in the Assessment Area. Generation on the system is integrated on a 100 percent Firm basis. Moreover, there are no project delays or temporary service outages for any transmission facilities (lines or transformers) that will impact long-term reliability during the assessment period.

The Hydro-Québec system has sufficient transmission being constructed to support all Future-Planned generation forecast to come on-line during the assessment period.

Vulnerability Assessment

Given the importance of hydro-electric resources within the Québec Area, an energy criterion has been developed to assess its energy reliability. The criterion states that sufficient resources should be available to go through sequences of two or four consecutive years of low water inflows totaling 64 TWh and 98 TWh respectively with a 2 percent probability of occurrence. These assessments are presented three times a year to the Québec Energy Board. Normal hydro conditions are projected over the assessment period, and reservoir levels are expected to be sufficient to meet both peak demands and daily energy demand.

A total of 1,500 MW is targeted by Under-Voltage Load Shedding (UVLS) in the Québec Area. It has been designed to operate following contingencies involving the loss of two or more 735 kV lines. These contingencies do not require more than 1,500 MW of load shedding, although UVLS operates on a pre-defined pool of 2,500 MW located in the Montréal Area. The NPCC Comprehensive Review Assessment of the Québec Transmission System for 2012 (the last Comprehensive Review to date) conducted by Hydro-Québec TransÉnergie (acting as Transmission Planner) shows that UVLS is adequate to preserve system stability after the contingencies for which it is designed.

Contingencies range from the loss of two parallel 735 kV lines to the loss of a 735 kV line with series compensation bypass on parallel lines. The number of automatic actions needed to stabilize the system increases with the severity of the contingencies, but the whole analysis indicates a stable and well-damped system response for all contingencies. This assessment indicates that no voltage or reactive power problems having an adverse impact on the BPS are anticipated under complementary contingency requirements. No additional load is expected to be assigned to UVLS during the next 10 years.

Hydro-Québec maintains a permanent emergency plan in case of catastrophic events. This stems from a number of federal and provincial legislation, rules, procedures and municipal by-laws. At the corporate level, Order #24 “Service Continuity and Emergency Measures” and Corporate Policy “Our Security” form the basis on which the plan is built. The Corporate Plan is prepared by the Industrial Security Group at Hydro-Québec. It includes the plan’s objectives, risks covered by the plan, the organization around the plan (Steering Committee and Coordinating Committee), communications, and updating. Risks cover a large array of situations, for example, rupturing of a dam or dike, a nuclear incident, extensive damage to

transmission lines and stations, forest fires, unavailability of computer systems or telecommunications systems, biological risks, cyber criminality, terrorism, etc. The plan also provides links with the Québec Civil Security Organization and other civil, military, or medical organizations. This Corporate Plan directs Hydro-Québec's divisions to elaborate and maintain their own sectorial plan according to their field of activities.

Hydro-Québec TransÉnergie's Plan is based on eight different types of risk that the system has a probability of experiencing. These risk types are associated with criteria determining their impact on the system. Studies have determined the probability of occurrence and an impact level on a scale from 1 to 9 is associated with the risk type.

For each risk type, a file has been developed defining the risk, possible source events, potential impact, risk evaluation (probability of occurrence), mitigation procedures, post-mortem and follow-up requirements.

The planning process for catastrophic events completes system planning as required by NPCC's Regional Reliability Reference Directory #1–Design and Operation of the BPS and by NERC's Transmission Planning Standards. These standards define a number of system events that must be assessed under specified conditions. For NPCC, this includes an Extreme Contingency Assessment with, for example, loss of the entire capability of a generating station, loss of all transmission circuits in a common right-of-way, the sudden dropping of a large load or major load center, or the sudden loss of fuel delivery systems to multiple plants. Not all of these events apply to TransÉnergie. For example, only one natural gas-fired plant exists in the Québec Area, generating 547 MW, so that a pipeline failure is of little consequence to the system in this case. However, since bulk transmission is 735 kV, TransÉnergie physically limits the number of 735 kV lines in a common right-of-way to a maximum of two lines, because the loss of a right-of-way has a definite impact. Sudden dropping of large load centers, loss of generation stations, and loss of a 735 kV switching station are extreme events covered by Special Protection Systems, which limit the event's impact on the system.

In the case of an extreme contingency leading to a system blackout, there is an automatic device called SPSR (French acronym for "System Separation Solution") that acts locally at a number of 735 kV stations to close in sacrificial Zinc Oxide surge arrestors before the system dismantles. System collapse is accompanied by over voltages that would damage equipment if not dampened by the surge arrestors. This makes it possible to restore the system in minimum time with maximum equipment availability after a blackout. The surge arrestors themselves must be replaced after such an event.

Hydro-Québec intends to deploy a number of new technologies, systems, and tools to improve BPS reliability in the future. Smart grid incentives are among them. Government policies and targets for renewable energy integration, Energy Efficiency, electric or rechargeable hybrid vehicles, and greenhouse gas emissions reductions are among the major drivers for the development of smart grid programs.

TransÉnergie's system consists of an extensive 735 kV network underlain with 315 kV, 230 kV, and 120 kV subsystems totaling close to 22,800 circuit miles. The system uses telecommunications and advanced protection and control applications to ensure its reliability and improve its performance. This will continue into the future. The system is planned according to NPCC and NERC planning standards but with additional criteria that consider system topology and substation characteristics particular to TransÉnergie's system (Complementary contingencies) and address voltage sensitivity to load variation and interconnection ramping. Special Protection Systems to provide additional reliability (for extreme events) are presently in use and will continue to be used. These include Remote Generation Rejection and Load Shedding, Under-Voltage Remote Load Shedding, and Under-Frequency Load Shedding. It is not planned that Special Protection Systems or Remedial Action Schemes will be installed in lieu of planned bulk power transmission facilities in the Québec Area.

Other technologies such as synchronous condensers, Static Var Compensators (SVCs), 735 kV series compensation, multi-band power system stabilizers (MBPSS), HVdc systems, and a variable frequency transformer (VFT) are in use. Such systems are planned for future system upgrades or for generation integration as needed.

For more than two decades now, TransÉnergie has been operating an angular displacement measuring system to accurately monitor and register system frequency and angular displacement between major generating stations and load centers. This is used for on-line reporting and provides priceless post-mortem data for all system events involving frequency variations and angular displacements. The system also measures voltage and current distortion and is quite valuable for monitoring harmonic content during solar magnetic disturbances (SMDs).

Simulation tools are constantly being developed by TransÉnergie for planning purposes. These load forecasting tools, including local weather forecasts provided by TransÉnergie staff. These efforts contribute to the TransÉnergie Operation Planning Department that receives assistance from Hydro-Québec's Research Institute (IREQ) as well as the Université de Liège in Belgium, working to develop a number of system simulation software packages for in-house use. These include on-line dynamic security assessments (DSA), voltage sensitivity due to load and generation variations, massive stability simulations, voltage stability, real-time load modeling, and research on motor load modeling. DSA applications have been the object of joint (TransÉnergie and IREQ) IEEE papers.

Another project looks at regulation systems and SPS improvement in order to upgrade transfer capability and improve system reliability. This includes installation of MBPSSs in a great number of generating stations, new regulation circuits for the dynamic shunt compensation equipment, new relaying for Special Protection Systems, new control strategies for HVdc converters, development of severity indices for angular and voltage stability, etc. The project is also studying the possibility of introducing a type of global regulation for dynamic shunt equipment (as opposed to regulation based on local parameters) implying Measurement Units, a Data Concentrator, and Control Units, all linked by synchronized digital communications.

During the past year, no new smart grid programs were fully implemented at Hydro-Québec. The IMAGINE project is ongoing. IMAGINE involves automated maintenance and enhanced processing of monitoring data. Altogether, 94 substations are now connected to two remote maintenance centres, one in Montréal and one in Québec City. This project, which focuses first and foremost on power transformers, will enable TransÉnergie to optimize target maintenance efforts to prevent equipment failures and improve system reliability. Fault location data will be shared with Hydro-Québec Distribution, which will reduce recovery time. This project will also help Hydro-Québec meet NERC CIP requirements pertaining to cyber assets by providing an automated inventory of protection and control device passwords. The IMAGINE investment is over-budget for initiatives that are also accomplished through IREQ, Hydro-Québec's research center, with the help of industrial partners.

TransÉnergie is also working with IREQ to prepare the smart transmission grid of the future. In 2010, the main outlines of an adaptive power grid were sketched out. The grid would be equipped with controllers, sensors, analysis systems and other devices necessary to monitor equipment continuously and manage the system and its components in real time. Related projects include the ACOR grid response improvement program, which is designed to increase system capacity, reliability, and security by means of advanced protections and controls.

All relay operations are submitted to systematic and thorough analysis by TransÉnergie's "Analyses et comportement du réseau principal et des réseaux régionaux" (Bulk and Regional System Behavior and Analysis) unit, where primary causes of relay operations are studied and determined. When misoperations do occur, corrective actions and recommendations are issued and transposed to other installations when required. This is done through Maintenance Notices issued to Maintenance Units. Recommendation follow-up is certified through the SADA system (SPS and Protection Analysis System).

Concerning protection equipment durability, a TransÉnergie working group makes sure that data pertaining to control systems and protection systems are up-to-date at all times. A log sheet containing replacement priorities (on a scale of 1 to 9) and timelines for protection equipment is also kept up-to-date. A yearly follow-up is done to re-evaluate priorities and account for the work done and remaining. Evaluations of problematic systems are kept on file for ongoing referencing.

Finally, as a member of the Western Climate Initiative[238], the province of Québec implemented a cap-and-trade system in 2012, with the first compliance period planned to start January 1, 2013. Given the proportion of renewable generation in the Québec Area, this new regulation will not impact the Québec Area's reliability.

Standing and Emerging Reliability Issues

This section briefly discusses some important issues that may impact system reliability during the assessment period. There is no doubt that developments during recent years have contributed to a more reliable system. However, sustainable system reliability may be challenged by several issues. Two of them are considered as standing reliability issues and are described and analyzed below.

Wind Plant Integration to Grid

As a separate NERC Interconnection, the Québec subregion is responsible for its own frequency regulation. System inertia is quite low compared to the Eastern Interconnection, for example. Large post-contingency frequency excursions—up to ±1.5 Hz—can occur after normal contingencies, and it is required to set operating limits related to post-contingency frequency behavior.

Through 2015, Hydro-Québec will have integrated around 3,350 MW of nameplate wind capacity. This kind of large-scale integration of wind capacity on the system has triggered a need for frequency support by wind plants. In order to maintain actual system performance, TransÉnergie (the System Planner) has requested from manufacturers an inertia emulation function that would cover lack of inertia and spinning reserve from modern variable speed wind turbine generators. TransÉnergie is presently in the process of quantifying its inertia emulation needs. This is an ongoing interactive process with manufacturers. TransÉnergie is now in the process of procuring and validating manufacturers' inertia emulation model functions for wind plants. Inertia emulation is required for Hydro-Québec Distribution's wind generation resulting from the second and third calls for tenders, totaling 2,290 MW of capacity. Further studies will have to be made if wind capacity integration is extended in the mid-term.

Equipment Aging and Sustainability

Equipment aging and sustainability have been standing issues at TransÉnergie for more than 15 years (line and station equipment). However, during the years 2000–2010, it became obvious that a global strategic investment policy was needed to tackle the issue. The strategy is based on the risk (sustainability) of losing equipment due to a major failure when the equipment is approaching the end of its life cycle. This risk assessment considers the probability of a major failure and its impact on the transmission system and on TransÉnergie as an asset owner. The strategy put forward in 2007 was presented to the Québec Energy Board and authorized by the Board with an accompanying annual budget.

Issues that could impact reliability in the context of equipment aging are the following:

- Significant investment cuts
- Personnel and equipment availability for maintenance outages as well as new projects
- System availability for outages

At this time, there is no major concern regarding these issues that could have an impact on the BPS.

[238] The Western Climate Initiative is a collaboration of independent jurisdictions working together to identify, evaluate, and implement emissions trading policies to tackle climate change at a regional level. http://www.mddep.gouv.qc.ca/changements/plan_action/index-en.htm

PJM

Planning Reserve Margins

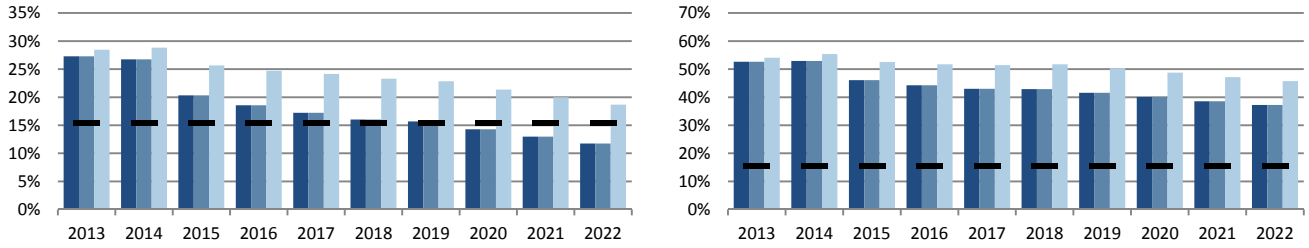
The PJM RTO will have adequate Planning Reserve Margins for all three categories throughout the 2019 summer season. It is expected that some Conceptual queued units will eventually become planned and placed in service to make up the amount below the NERC Reference Margin Level, beginning in 2020. The current PJM RTO Reserve Requirement is 15.6 percent through May 31, 2013. For the remainder of the assessment period, the PJM Reserve Requirement is 15.4 percent, applied as the NERC Reference Margin Level throughout this long-term assessment (PJM-Table 1 and PJM-Figure 1).[239]

PJM-Table 1: Planning Reserve Margins

PJM-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		27.28%	26.76%	20.34%	18.58%	17.24%	16.04%	15.69%	14.29%	12.98%	11.75%
PROSPECTIVE		27.28%	26.76%	20.34%	18.58%	17.24%	16.04%	15.69%	14.29%	12.98%	11.75%
ADJUSTED POTENTIAL		28.45%	28.83%	25.66%	24.72%	24.14%	23.29%	22.85%	21.37%	19.98%	18.67%
NERC REFERENCE	-	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**

PJM-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		52.63%	52.90%	46.10%	44.24%	42.99%	42.90%	41.60%	40.07%	38.56%	37.23%
PROSPECTIVE		52.63%	52.90%	46.10%	44.24%	42.99%	42.90%	41.60%	40.07%	38.56%	37.23%
ADJUSTED POTENTIAL		54.03%	55.39%	52.55%	51.71%	51.41%	51.74%	50.36%	48.74%	47.14%	45.73%
NERC REFERENCE	-	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**

PJM-Figure 1: Summer (Left) and Winter[240] (Right) Planning Reserve Margins



The PJM Reliability Pricing Model (RPM) or Forward Capacity Market provides:

- procurement of capacity three years before it is needed through a competitive auction;
- locational pricing for capacity that reflects limitations on the transmission system's ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;
- a variable resource requirement to help set the price for capacity;
- a backstop mechanism to ensure that sufficient resources will be available to preserve system reliability.

The Anticipated Capacity Reserve Margin falls below the PJM required reserve margin in 2020. The adjusted potential resources Reserve Margin is above the PJM requirement through the assessment period. The major contributing factor to the shortfall is significant retirements. It is expected that generator developers will make up the shortfall in those future years. Continued use of the PJM RPM will ensure that the Planning Reserve Margin is met at least three years into the future. A potential issue that could lead to incorrect projections is significant load growth well beyond what is expected. Also, planned units not coming on-line would affect the PJM reserve margin in the long-term future, but the RPM is anticipated to provide adequate resources in the three-year near term when that time horizon is experienced.

[239] For more information, see the 2011 PJM Reserve Requirement Study: http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/2011-rrs-study.ashx.

[240] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Demand

Summer peak load growth for the PJM RTO is projected to average 1.36 percent per year over the next 10 years. The PJM RTO summer peak is forecast to be 176,420 MW in 2022, a 10-year increase of 20,166 MW (PJM-Table 2). Annualized 10-year growth rates for individual PJM transmission zones range from 0.9 percent to 1.9 percent.

PJM-Table 2: Demand Outlook

PJM-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	145,254	163,220	17,966	12.4%	1.30%
Load-Modifying Demand Response	11,000	13,200	2,200	20.0%	2.05%
TOTAL INTERNAL DEMAND	**156,254**	**176,420**	**20,166**	**12.9%**	**1.36%**

PJM-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	121,160	132,916	11,756	9.7%	1.03%
Load-Modifying Demand Response	11,000	13,200	2,200	20.0%	2.05%
TOTAL INTERNAL DEMAND	**132,160**	**146,116**	**13,956**	**10.6%**	**1.12%**

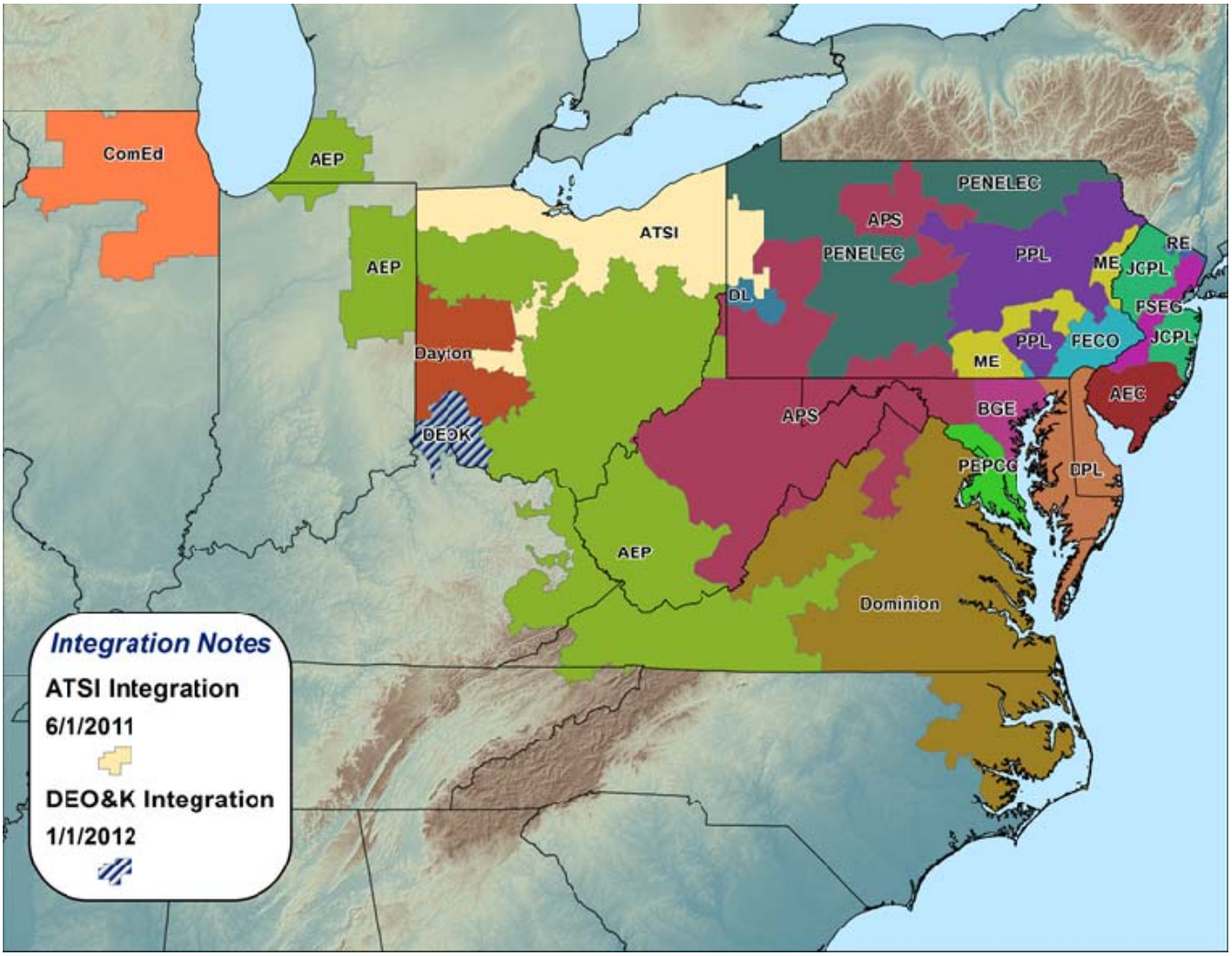
A downward revision to the near-term economic outlook for both the United States and PJM Area resulted in lower peak and energy forecasts in the 2012 load forecast compared to the 2011 load forecast. This is tied to revised assumptions regarding the timing of the recovery of the U.S. economy. While growth in later years accelerates, the historic growth rate will not be restored until past the assessment period.

This year's forecast reflects PJM's adoption of an independent consultant's recommendation to replace the load model's previous economic driver (Gross Metropolitan Product) with a variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment). A summary report of economic assumptions used in the 2012 load forecast provided by Moody's Analytics states that:

> *Mid-Atlantic and Virginia Areas are expected to be among the fastest growing in the PJM service territory. Long-term growth in these metro areas will be driven by highly educated labor forces, favorable demographics, productivity growth, and for some Virginia metro areas, plentiful and affordable housing, and relatively low costs. Metro areas in Ohio and Pennsylvania are expected to grow more slowly. Expansion in those states will be more restrained as regions transition away from manufacturing toward more services-oriented economies.*

No footprint changes are included in these calculations. East Kentucky Power Cooperative (EKPC) has announced its intention to join PJM on June 1, 2013. EKPC is a not-for-profit, member-owned cooperative providing wholesale electricity to 16 owner-member distribution cooperatives that serve 520,000 homes, farms, and businesses across 87 of the 120 counties in Kentucky. EKPC owns and operates four major power plants with a total generating capacity of about 3,000 megawatts, as well as approximately 2,800 miles of high-voltage transmission line. Peak load was 2,889 MW. No other entity acquisitions or exits are anticipated. A map of the current PJM footprint is provided on the next page (PJM-Figure 2).

PJM-Figure 2: PJM Footprint



PJM-Table 3: PJM Entities

AEC - Atlantic City Electric	Dayton - Dayton Power and Light	ME - Metropolitan Edison
AEP - American Electric Power Service Corporation	DEOK - Duke Ohio and Kentucky	PECO - PECO Energy Company
APS - Allegheny Power	DL - Duquesne Light Company	PENELEC - Pennsylvania Electric
ATSI - American Transmission Systems Incorporated	Dominion – Virginia Electric Power Company	PEPCO - Potomac Electric Power Company
BGE - Baltimore Gas and Electric	DPL - Delmarva Power and Light	PPL - PPL Electric Utilities
ComEd - Commonwealth Edison Company	JCPL - Jersey Central Power and Light	PSEG - Public Service Electric and Gas

Demand-Side Management

Last year PJM had 11,600 MW of Demand-Side resources available during the summer peak period. PJM expects similar amounts for this year's summer peak period. Because PJM has a shorter history with accepting Demand Response and Energy Efficiency, the forecasts are conservative. Accordingly, Demand Response will remain slightly below was available during the 2011 peak. The Energy Efficiency will increase from 728 MW in 2013 to 804 MW in 2022 (PJM-Table 3).

PJM-Table 4: Projected Demand-Side Management

	Short-Term					
PJM-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	1,000	1,000	1,000	1,000	0	0.57%
Contractually Interruptible (Curtailable)	5,000	7,200	7,200	7,200	2,200	4.08%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	5,000	5,000	5,000	5,000	0	2.83%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	11,000	13,200	13,200	13,200	2,200	7.48%
TOTAL ENERGY EFFICIENCY	728	804	804	804	76	0.46%
TOTAL DEMAND-SIDE MANAGEMENT	**11,728**	**14,004**	**14,004**	**14,004**	**2,276**	**7.94%**

Demand-Side resources accepted through the Forward Capacity Market are DSM that is dispatched like generator resources and is treated as such. The more typical type of Demand-Side resource is the kind that is retained for use by the PJM operators during capacity emergencies, and it reduces load.

Energy Efficiency programs are included in the 2013–2022 load forecasts with approval for use in the PJM Reliability Pricing Model (RPM). Energy Efficiency is included as a capacity resource in the RPM Market but is limited to a maximum of four years. The Energy Efficiency then becomes part of the load forecast. Measurement and verification of Energy Efficiency programs are governed by rules specified in PJM Manual 18B.[241] To demonstrate the value of an Energy Efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual by establishing Measurement and Verification (M&V) plans, providing post-installation M&V reports, and undergoing an M&V audit.

There are some minor concerns related to the amount of information available to PJM, which can be used to determine the amount of DR to dispatch during emergency conditions. PJM has filed tariff changes with FERC that will require more robust reporting of the DR operational capability in real time for Curtailment Service Providers. PJM does not have a reliability concern, but the additional information will help avoid the dispatch of DR that may not be necessary to meet the need of the emergency conditions. PJM has addressed the issue of availability by creating three different DR products: Limited DR (10 days for six hours per day), Extended Summer DR (unlimited days during summers for 10 hours per day) and Annual DR (unlimited days for 10 hours per day), and requiring the necessary amount of annual capacity (DR or generation) to fulfill the PJM reliability requirements. DSM used for reserves is limited by the RFC standard BAL-002-RFC-02 to 25 percent of the Operating Reserve requirement. This type of DSM is typically fully subscribed and can range up to approximately 2,500 MW during a peak summer day.

Generation

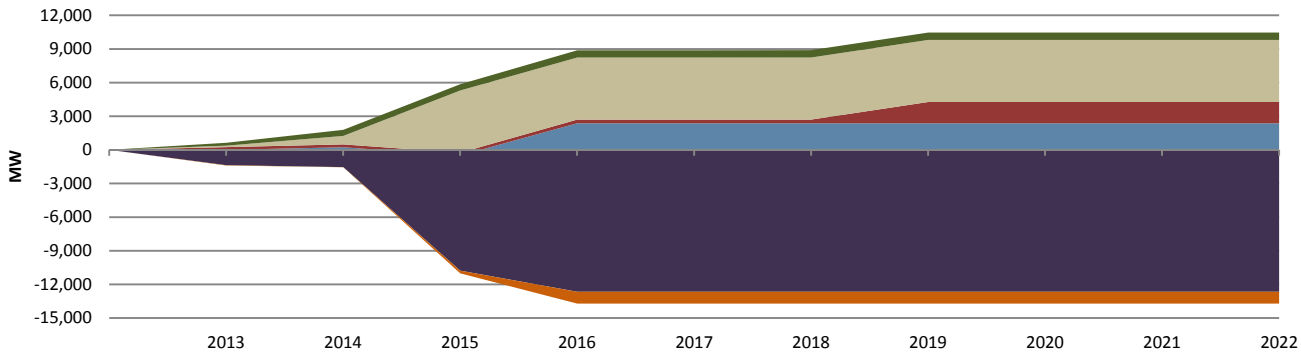
The predominant source of fuel in PJM is coal at approximately 42 percent. Next is natural gas at 26 percent and nuclear at 18 percent. Since the 2011 assessment, along with the DOEK generation, PJM added 1,608 MW of natural gas generation, 117 MW of existing nuclear generation uprates are included, and 280 MW of nameplate wind generation with 42 MW counted as Existing-Certain. In addition, 70 MW of nameplate solar generation with 27 MW counted as Existing-Certain (PJM-Table 6, PJM-Figure 3, and PJM-Table 7). No capacity resource changes are expected though the summer of 2012. All capacity changes in PJM occur only on June 1 of each year (PJM-Table 5 and PJM-Figure 4).

[241] http://www.pjm.com/~/media/documents/manuals/m18b.ashx.

PJM-Table 5: Capacity Outlook[242]

	Current		2022 Planned			2022 Planned & Conceptual		
PJM-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	78,105	42.1%	65,455	35.9%	-12,650	67,310	28.9%	-10,795
Petroleum	11,739	6.3%	10,683	5.9%	-1,056	10,688	4.6%	-1,051
Gas	52,395	28.3%	54,763	30.1%	2,368	92,554	39.8%	40,160
Nuclear	33,666	18.2%	35,566	19.5%	1,900	38,427	16.5%	4,761
Other/Unknown	0	0.0%	5,542	3.0%	5,542	5,916	2.5%	5,916
Renewables	9,519	5.1%	10,173	5.6%	654	17,857	7.7%	8,338
TOTAL	**185,424**	**100.0%**	**182,182**	**100.0%**	**-3,242**	**232,752**	**100.0%**	**47,329**

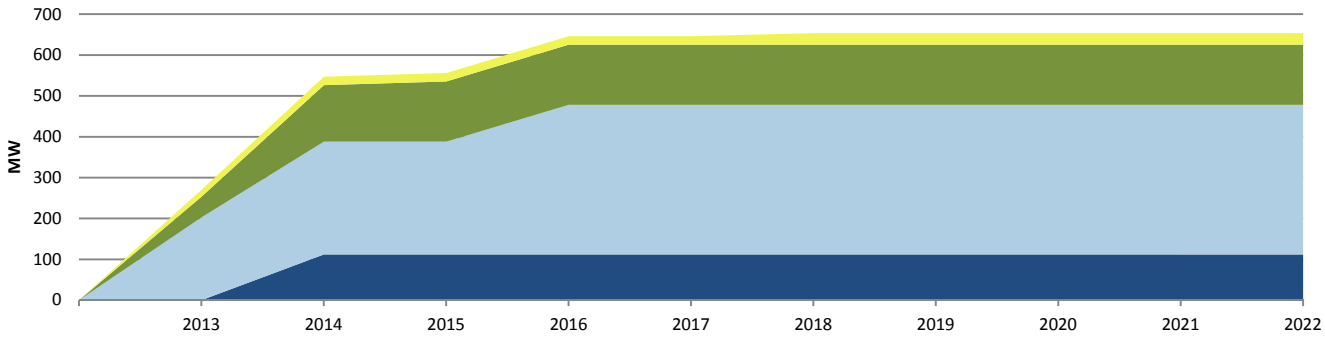
PJM-Figure 3: Summer Net Capacity Change



PJM-Table 6: Renewable Capacity Outlook[243]

	Current		2022 Planned			2022 Planned & Conceptual		
PJM-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	2,677	28.1%	2,789	27.4%	112	2,989	16.7%	312
Pumped Storage	5,145	54.0%	5,145	50.6%	0	5,145	28.8%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	711	7.5%	1,078	10.6%	366	6,936	38.8%	6,225
Biomass	943	9.9%	1,090	10.7%	147	1,438	8.1%	494
Solar	42	0.4%	71	0.7%	28	1,349	7.6%	1,306
TOTAL	**9,519**	**100.0%**	**10,173**	**100.0%**	**654**	**17,857**	**100.0%**	**8,338**

PJM-Figure 4: Summer Net Renewable Capacity Change



[242] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[243] *Ibid*.

PJM-Table 7: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
PJM-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	5,472	106	2,677	943	7,391	175	2,789	1,090
On-Peak Derate	4,761	64	0	0	6,313	104	0	0
EXPECTED ON-PEAK OUTPUT	711	42	2,677	943	1,078	71	2,789	1,090

PJM had a total increase of 5,007 MW since last summer almost completely due to the addition of DEOK generation. Generation additions and retirements in the rest of PJM almost netted out. A new natural gas combined-cycle unit at Dresden was added at 545 MW. Kearny natural gas units 13 and 14 were added for 267 MW. A new natural gas combined-cycle unit named Virginia City was added in AEP for 585 MW.

Martins Creek 4 oil unit was uprated 70 MW in PPL. Susquehanna nuclear units 1 and 2 in PPL were uprated 45 MW each. A net of 568 MW of uprates and derates also occurred.

Benning 15 and 16, totaling 548 MW of oil generation, were retired in the Baltimore Gas and Electric (BGE) footprint. Gorsuch units 1–4, totaling 189 MW of coal generation, were retired in AEP. The Buzzard Point East and West oil CTs totaling 210 MW were retired in Pepco. The Hudson 1 natural gas unit at 322 MW was retired in PSE&G. Also in PSE&G the Kearny 10 and 11 natural gas units were retired for a loss of 250 MW. The State Line 3 and 4 units were retired from ComEd, totaling 515 MW.

No units were brought back into service since the last assessment. PJM has no on-going long-term outages of generation. There are no significant project deferrals or cancellations; occasional delays are expected but should not cause any reliability problems. Behind-the-meter generation is not considered as capacity in PJM. It offsets load that is also behind the meter.

The Laurel Mountain Energy Storage Facility consists of eight Smart Grid Stabilization System Lithium Ion battery modules for a total output of 27.4 MW on the same site as the Laurel Mountain Wind Farm located at Laurel Mountain, West Virginia. A two MW (300 kilowatt hours of storage) battery for frequency regulation has been installed on the same property as the Paradise Solar project in Deptford, New Jersey.

PJM uses the maximum generator capability expected capacity on-peak (Existing-Certain). This capability may only be available for a limited period of time, but PJM requires that units be able to produce this amount over the peak hours. PJM requires annual verification of this capability. Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors, which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked, and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual unit's capacity factor. No enhancements have been made as to how expected on-peak capacity values are calculated for each resource in PJM. PJM does not anticipate any reliability concerns resulting from minimum demand and over generation. Intermittent resources can be required to disconnect. Established procedures address reliability concerns caused by over-generation.

Capacity Transactions

All transactions are Firm for both specific generation and transmission (PJM-Table 8). Firm contacts are mostly long-term, but some are shorter in the one- to three-year time frames. All transactions are assumed to continue through the entire assessment period unless a termination date has been specified. While it is possible that the termination dates could be extended, experience shows that the transaction usually ends on the date contracted. PJM has no reliance on outside assistance for emergency imports. There is no emergency generation needed to be available to meet PJM Reserve Margin Requirement.

PJM-Table 8: Projected Capacity Transactions

PJM-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453
TOTAL IMPORTS	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236
TOTAL EXPORTS	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236
TOTAL NET CAPACITY TRANSACTIONS	**217**	**217**	**217**	**217**	**217**	**217**	**217**	**217**	**217**	**217**

Transmission

Today, as part of its ongoing RTO responsibilities, PJM's Regional Transmission Expansion Plan (RTEP) protocol comprises a process that considers the aggregate effects of many system trends: long-term growth in electricity use, generating plant retirements, broader generation development patterns—including the evolution of renewable resources—as well as Demand-Side response (DSR) programs and Energy Efficiency (EE) programs. A summary of expected and existing transmission additions is included below (PJM-Table 9).

PJM-Table 9: Existing and Projected Transmission

PJM	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	51,583	66	51,649
Currently Under Construction	118	0	118
Planned - Completed within First Five Years	709	0	709
Planned - Completed within Second Five Years	1,267	0	1,267
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	53,677	66	53,743
Conceptual - Completed within First Five Years	131	0	131
Conceptual - Completed within Second Five Years	134	0	134
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**53,942**	**66**	**54,008**

This process culminates in one recommended plan (one RTEP) for the entire PJM footprint that is submitted to PJM's independent Board of Managers (PJM Board) for consideration and approval. Under contractual agreement, the PJM Board's approval then obligates transmission-owning utilities in PJM to build the facilities specified in the RTEP. This includes construction of new transmission lines and other facilities as well as upgrades to existing transmission assets.

The RTO Perspective

PJM operates and plans the transmission system region-wide, as a whole, ignoring corporate and state boundaries when taking operational action or making planning decisions. By planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis, PJM's RTEP process helps focus on transmission upgrades that meet Reliability Criteria and increase economic efficiency more effectively. PJM's existing RTEP Protocol[244] has been applied by PJM so as to evaluate reliability and market efficiency driving transmission expansion plans today using bright line triggers.

Baseline Reliability Upgrades

PJM's baseline reliability assessments identify areas where the electric power system, forecast over a specific time, would not be in compliance with NERC Reliability Standards. These baseline assessments lead to recommendations for enhancement plans, referred to as baseline transmission network upgrades, to ensure compliance with those standards. Fundamentally, the construction of baseline transmission upgrades is required to ensure that the PJM system remains in compliance with NERC Reliability Standards. This baseline then serves as the basis for the analysis of subsequent requests for transmission service and interconnection.

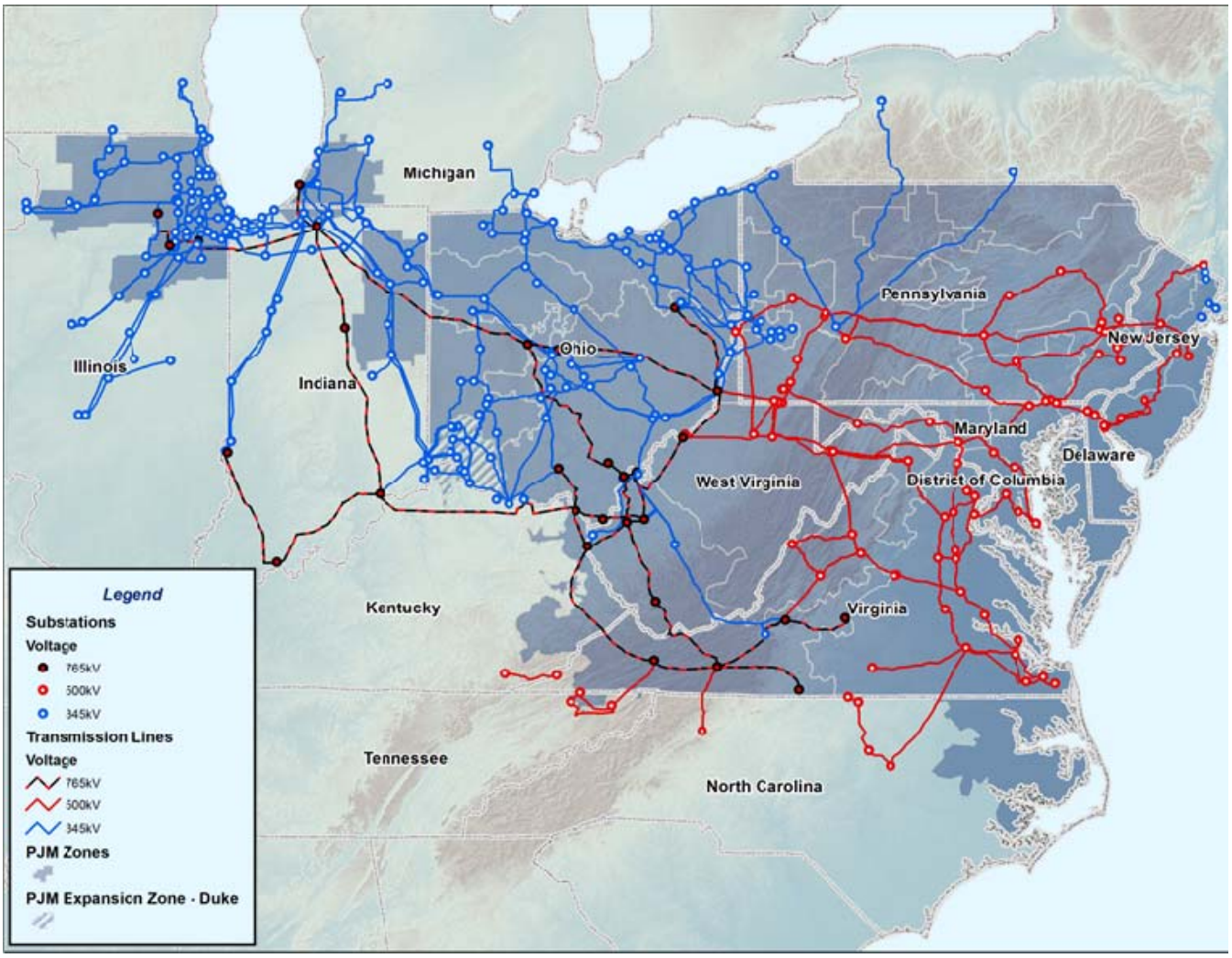
Scope of Upgrades Discussed

In 2011 alone, the PJM Board approved approximately 400 individual Bulk Electric System (BES) upgrades. However, to put reasonable parameters around the scope and length of this report, the upgrades discussed here are generally those whose

[244] As codified in Schedule 6 of PJM's Operating Agreement (http://www.pjm.com/documents/~/media/documents/agreements/oa.ashx) and described in detail in the PJM manuals (http://www.pjm.com/documents/manuals.aspx).

costs exceed $5 million. A complete list of all approved RTEP upgrades, a brief description of facility and driver, and current status can be found on PJM's website.[245] The map on the next page presents major transmission infrastructure in the PJM Assessment Area footprint (PJM-Figure 5).

PJM-Figure56: Existing Backbone Transmission



TrAIL

The 500 kV Trans Allegheny Interstate Line (TrAIL) was placed in service on May 23, 2011, improving reliability into such congested areas as Washington, D.C., Baltimore, and northern Virginia. The TrAIL line was built in three segments, connecting substations in southwestern Pennsylvania, northern West Virginia and northern Virginia as shown on Map 1.3. Built by and jointly owned by Allegheny Energy (now FirstEnergy) and Dominion, the 220-mile TrAIL line was the first high-voltage backbone transmission line approved by the PJM Board through PJM's planning process to enter commercial operation.

MAPP Abeyance

The Mid-Atlantic Power Pathway (MAPP), shown on Map 1.3, was placed in abeyance by the PJM Board on August 18, 2011. PJM 2011 RTEP generator sensitivity analysis indicated that the need for the line has moved out several years, beyond

[245] http://www.pjm.com/planning/ rtep-upgrades-status/construct-status.aspx.

2015, but as early as 2019. The PJM Board has also directed PJM to perform additional sensitivity analyses as part of the 2012 RTEP cycle of analysis—including the impact of May 2012 RPM auction results—to assess the need to further address MAPP abeyance.

Susquehanna–Roseland

In 2007 the PJM Board approved the Susquehanna–Roseland 500 kV line, shown on Map 1.3, to resolve numerous overloads on critical 230 kV circuits across eastern Pennsylvania and northern New Jersey beginning in 2012. PJM's 2008 RTEP Retool validated the required June 1, 2012 in-service date in light of 23 single contingency Reliability Criteria thermal violations and NERC Category C double-circuit tower line contingency thermal violations. PJM's 2009 RTEP Retool analysis for 2012 also included an assessment of the continued need for the Susquehanna–Roseland 500 kV line. Based on the identification of 13 single contingency thermal overloads and 10 double-circuit tower line outage overloads, PJM re-validated the line's June 1, 2012 in-service date.

PJM conducted additional analysis in 2011 to assess the impact of delays to the construction. Originally required to be in service by June 1 2012, regulatory delays have pushed the expected in-service date to June 1, 2015. Updated analysis using the 2011 load forecast confirmed double-circuit tower line (DCTL) violations beginning in summer 2012. The near-term solution is to operate to the DCTL violations in real-time operation and adjust generation and implement Demand-Side Response (DSR) as required to maintain grid reliability. Updated studies also show that Hudson Unit 1, previously designated as a reliability-must-run unit, is not required to maintain reliability and will be released.

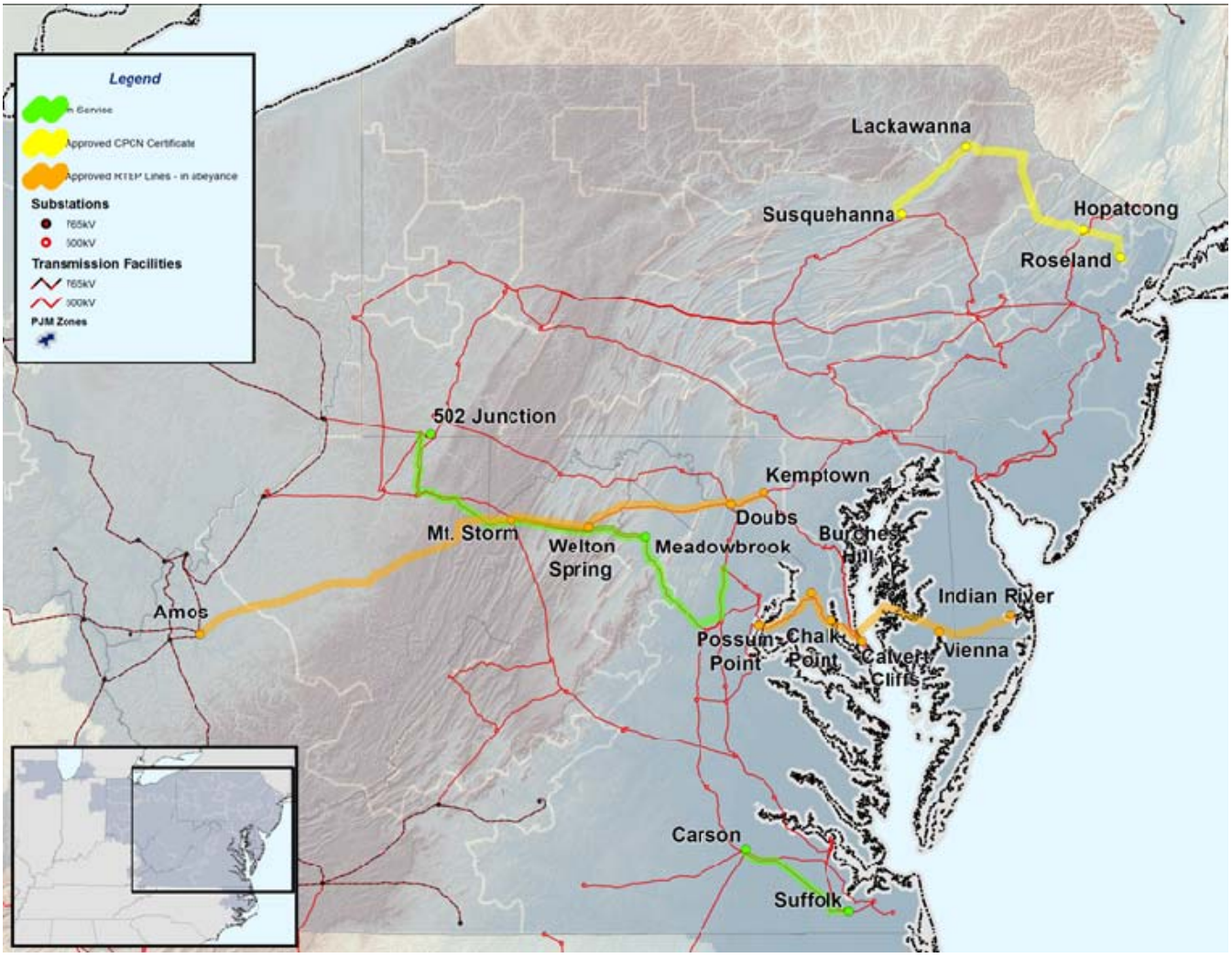
PATH Abeyance

Analysis performed during the 2010 RTEP cycle required an in-service date of June 1, 2015 for the PATH Line as shown on Map 1.3. The PJM Board issued a statement on February 28, 2011, suspending the PATH line.

PJM staff performed an updated analysis based on the 2011 RTEP assumptions that included generation deliverability and load. Additional analysis performed on a 2017 study year case with 2011 RTEP assumptions examined the impact on the PATH abeyance from Warren Generation, Global Insights load forecast, RPS, at-risk generation and state DSR/EE goals. The 2011 RTEP analysis suggests that the need for the PATH line has moved several years beyond 2015. Based on these analyses the PJM Board decided to continue to hold the project in abeyance and requested that the Transmission Owners suspend development activities. Furthermore, the PJM Board has directed staff to perform additional analysis using the 2012 RTEP assumptions and incorporating May RPM base residual auction results.

The map on the next page presents transmission upgrades that were underway in early 2012 (PJM-Figure 6).

PJM-Figure 6: Significant Transmission Upgrades



PJM evaluates transmission congestion continuously. When congestion costs become uneconomical related to the cost of transmission construction, transmission enhancement is considered. The PJM Board has the final say on whether a project is developed to mitigate congestion charges. PJM has a number of projects to tap lines for generation interconnection or for load serving. See the map of PJM above to see where significant transmission is being added. There are no interconnection-related projects or issues in PJM. There are no project delays or temporary service outages for transmission facilities (lines or transformers) that will impact reliability during the assessment period. The potential reliability impact of not meeting target in-service dates for projects is under constant review to identify alternate plans or mitigating operational actions that should be taken in the event of project delays. Available mitigating measures include re-dispatch of generation, operating procedures, and temporary Special Protection Schemes.

In PJM, generation-seeking capacity revenue must expand the transmission system so as to enable their deliverability to the PJM system. Therefore, sufficient transmission will exist for any new capacity project in PJM.

Static Var Compensators (SVC) to be Installed:

- Frost Bridge 138 kV; FirstEnergy (AP); 70 Mvar; 6/1/12
- Meadowbrook 500 kV; Primary Power; 600 Mvar; 6/1/14
- Mt. Storm 500 kV; Primary Power; 250 Mvar; 6/1/14
- Hunterstown 500 kV; FirstEnergy (ME); 500 Mvar; 6/1/14

- Altoona 230 kV; FirstEnergy (ME); 250 Mvar; 6/1/14

Fast Switching Capacitors

- Mansfield 345 kV; FirstEnergy (PN); 100 Mvar; 6/1/14
- Jack's Mountain 500 kV; FirstEnergy (PN); 100 Mvar; 6/1/17
- Jack's Mountain 500 kV; FirstEnergy (PN); 500 Mvar; 6/1/17

HVdc

- Bergen 230 kV (PSE&G-NJ)–49th Street 345 kV (ConEd–NY) 670 MW; 6/1/13

Vulnerability Assessment

PJM has very little hydro generation, and reservoir levels are adequate. PJM expects no problems with warm cooling water. Any one specific generator outage, even if it is long-term, can be replaced with other resources available within PJM.

Significant development of wind, solar, and biomass has already occurred in PJM. Much of this development is in response to existing Renewable Portfolio Standards (RPS). The challenges of integrating this variable generation will grow as more and more generation of this type is added. Demand-Side resources are not of significant size to be of great concern for unresponsiveness. Penalties exist to make unresponsiveness financially unattractive. Distributed generation has been increasing in PJM, especially solar installations, which are mostly connected to lower voltage lines. No special operating procedures are required. PJM has developed a Wind Power Forecast tool and visualization to assist operations.

No additional Under-Voltage Load Shedding (UVLS) schemes are planned. No new Special Protection Systems are planned. PJM does not include planning for catastrophic/high-impact, low-frequency (HILF) events.

Significant smart grid programs include:

- Synchrophasor data may be integrated into operational, planning, and study tools by 2022, and it is anticipated the data will be used in real-time operational decision making.
- PJM's transmission system will include FACTS devices, SVCs, Statcoms, and other technologies that will enable inverter-based generation to reliably connect to the system.
- Dynamic line ratings.
- In addition to renewable integration, PJM anticipates seeing more energy storage deployed across the grid in the form of batteries, thermal storage, flywheels, and perhaps even compressed air. It is possible some of these technologies will also be treated as transmission assets to help defer line upgrades.
- Automated Voltage Control (AVC) that will optimize the voltage schedule across the PJM footprint.
- Some form of automated/optimized restoration tool.
- On-line transient stability analysis tool that also recommends preventative control actions to operators.

Smart grid devices that may enhance reliability include synchrophasor implementation, which can help with better modeling and better real-time awareness of what's happening in the system and how the health of the system is trending. In addition, PJM's advanced technology pilot programs give PJM the opportunity to better understand the upcoming technologies, such as aggregated Demand Response and electric vehicle charging, along with their benefits and their challenges. PJM will have better insight into ways to optimize all the assets on the system.

Smart grid applications that may have a reliability concern include:

- It will take time to be comfortable with synchrophasor data and what it means. Great care and testing and analysis need to be taken while operators are still getting familiar with what the synchrophasor data means.
- The paradigm switch of load following generation and the need for load shaping, where possible (e.g., smart charging), and shifting, also better load forecasting and modeling.

PJM developed an analysis of coal generation at risk of retiring based on an assessment of required environmental retrofit costs vs. the cost of constructing a new natural gas-fired turbine. This at-risk generation analysis concluded that there is no overall resource adequacy concern for the PJM footprint; however, there may be localized reliability concerns that will need to be addressed either with replacement generation capacity or transmission upgrades if the impacted units are retired or need lengthy environmental retrofit outages. PJM continues to coordinate closely with PJM Generation Owners, PJM Transmission Owners and neighboring systems through the PJM committee structure and consistent with the PJM tariff and manuals. In order to maintain system reliability, PJM will designate units as reliability-must-run if their retirement date is targeted to be in advance of required system reinforcements.

PJM requested that all impacted generation owners provide the most accurate information regarding unit retirements, environmental retrofits, unit derates and potential regulatory issues related to the environmental regulations. Combined with the publically announced unit retirements and the deactivation analysis results, PJM is utilizing this information to address the short-term impact and long-term projections through 2018. PJM is communicating with interconnected Transmission Owners, as required, to address local reliability issues, and is also communicating with MISO to compare reliability analyses and coordinate outages. At this point PJM has added the environmental retrofit outages—to the extent provided by the generation owners—to projections for maintenance outages from 2012–2018, and are continuing to assess the impact to off-peak reliability. PJM will continue to coordinate closely to analyze the impact of retiring generation, planned outage to perform retrofits, normal generation, and transmission maintenance outages, as well as transmission outages required to reliably take retiring units out of service. Generation Owners have indicated that while there appears to be sufficient time to complete environmental retrofits, if there are delays in scheduling retrofit outages due to system constraint issues or capital budget limitations, then there may be significant challenges in completing the retrofit outages in the required time to comply with environmental regulations.

Standing and Emerging Reliability Issues

Retirement of capacity because of the environmental regulations and diminishing amounts of blackstart resources.

Retirement of Generation

The concern about generator retirements due to stricter environmental regulations is a standing issue that has previously been investigated by the NERC Reliability Assessment Subcommittee.

Because of the way that PJM plans their resources for the three-year-in-advance period, it is not likely to be an issue in the near term but may become an issue if interconnection of new resources does not match the retirement of existing resources. Drivers are the new, stricter environmental regulations. While some Generator Owners wait to see how quickly and strictly these new rules will be enforced, others are more transparent, announcing the future retirements far in advance. PJM RPM requires that units be removed at least three years in advance to avoid severe penalties. Loss of large generating resources can affect PJM's resource adequacy in obvious ways. At this time, loss of resources in the three-year time frame has amounted to approximately 10,000 MW. It is difficult to tell how much will be lost past that time frame. While it isn't thought that PJM would violate its reserve margin requirement, PJM may be operating closer to it. Replacement resources could be in different locations from the locations of retiring units, which could load up the transmission system more.

No changes to the reference case would be needed to model this issue because changes to resources as a result of this issue would happen in the future. Loss of resources would affect the entire PJM system. The method for retiring units in PJM allows for PJM to delay unit retirements if reliability issues exist.[246] See Manual 14d Section 9 – Generator Deactivations. Strict requirements for adherence to the new environmental regulations may cause reserve margins to get close to the required values. Some flexibility to allow for cost-effective replacement of resources is needed. Movement

[246] http://www.pjm.com/~/media/documents/manuals/m14d.ashx.

away from the existing coal fuel supply infrastructure will burden other fuel supplies and supply chains, like the transportation and storage of natural gas.

Loss of Blackstart Resources

The concern about blackstart resource retirements is an emerging issue that has been discussed but not analyzed. The time frame for this issue is today since PJM is already seeing fewer blackstart resources available. PJM establishes a minimum blackstart unit threshold of three units for each restoration zone. Drivers for the blackstart resources going away are maintenance and retrofit costs associated with keeping some of the older blackstart resources running. Other cost increases include retrofitting to comply with the new environmental regulations and, though significantly diminished, the cost associated with CIP compliance. Many blackstart unit owners also complain that the reimbursed costs received from PJM are not adequate.

Loss of blackstart resources will not affect reserve margins significantly. Blackstart resources are usually small units that contribute little to installed capacity. While not directly affecting reliability in PJM, loss of blackstart resources would lengthen a blackout. Transmission adequacy would not be affected by the loss of blackstart resources. Different cranking paths may need to be used, but the amounts of power transferred are small.

No changes to the reference case would be needed to model this issue. Since location of blackstart resources is considered Critical Energy Infrastructure information (CEII), location information will not be disclosed.

A blackstart generator replacement process exists but has proved to be ineffective. See Manual 14d Section 10 "Blackstart Replacement Process."[247] Since some of the blackstart resource retirements are related to the enforcement of stricter environmental regulations, strict adherence to those regulations and their time frames can exacerbate the blackstart availability issue.

[247] http://www.pjm.com/~/media/documents/manuals/m14d.ashx.

SERC-E

Planning Reserve Margins

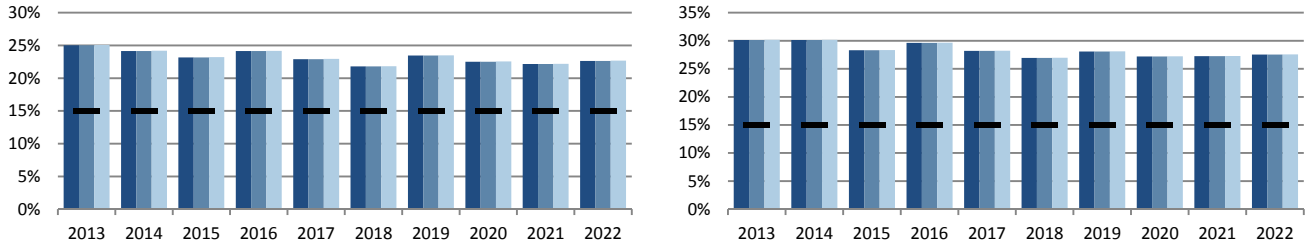
Reserves will provide adequate and reliable power supply throughout this assessment period. All Planning Reserve Margins are projected to remain above the NERC Reference Margin Level from 2013–2022 (SERC-E-Table 1 and SERC-E-Figure 1).

SERC-E-Table 1: Planning Reserve Margins

SERC-E-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		25.03%	24.16%	23.18%	24.15%	22.91%	21.80%	23.45%	22.52%	22.16%	22.64%
PROSPECTIVE		25.03%	24.16%	23.18%	24.15%	22.91%	21.80%	23.45%	22.52%	22.16%	22.64%
ADJUSTED POTENTIAL		25.07%	24.19%	23.21%	24.18%	22.94%	21.84%	23.48%	22.55%	22.19%	22.67%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-E-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		30.14%	30.14%	28.32%	29.63%	28.20%	26.95%	28.09%	27.19%	27.25%	27.53%
PROSPECTIVE		30.14%	30.14%	28.32%	29.63%	28.20%	26.95%	28.09%	27.19%	27.25%	27.53%
ADJUSTED POTENTIAL		30.17%	30.18%	28.35%	29.66%	28.23%	26.98%	28.12%	27.22%	27.28%	27.56%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-E-Figure 1: Summer (Left) and Winter[248] (Right) Planning Reserve Margins



SERC does not require specific Reserve Margin criteria or "targets" for SERC-E. Therefore, NERC applies the 15 percent Reference Margin Level throughout the assessment period. SERC utilities in North Carolina include renewables in their portfolios to meet the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under this standard, investor-owned utilities in North Carolina will be required to meet up to 12.5 percent of their energy needs through renewable energy resources or Energy Efficiency measures by 2021. Rural electric cooperatives and municipal electric suppliers are subject to a 10 percent REPS requirement.[249] Variable resources are assessed for their availability to meet the needs of customers reliably and economically, based on the requirements of the standard and maintaining flexibility in making long-term resource decisions. Reporting results show that utilities are planning for reserves in the range of 12 to 15 percent for the upcoming period.

No operational problems are anticipated that would detract from these projections. For the forecast and any extreme peaks, Reserve Margins are such that loss of multiple units can be accommodated without threatening reliability. The VACAR reserve sharing agreement[250] is also available to support recovery from such extreme events. Beyond these measures, transmission Reserve Margins can also be utilized to secure market purchases to maintain reliability. As stated in annual integrated resource plan filings with the North Carolina Utilities Commission (NCUC), various entities are evaluating a wide range of factors in order to ensure reliable and cost-effective service to customers. Over the next 10 years, entities will be evaluating numerous factors, such as new environmental requirements, renewable energy, new generation technologies and rising commodity costs.

[248] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.
[249] http://www.ncuc.commerce.state.nc.us/reps/reps.htm
[250] The VACAR-South Reliability Coordinator area includes portions of two southeastern states (North Carolina and South Carolina). There are five Balancing Authorities in SERC-E; Alcoa Power Generating, Inc. – Yadkin Division, Duke Energy Carolinas, Progress Energy Carolinas, South Carolina Electric & Gas Company, and South Carolina Public Service Authority.

Demand

Entities are projecting reductions in demand growth rates when compared to forecasts a year earlier. The compound annual growth rate (CAGR) for Total Internal Demand is projected to be 1.2 percent, slightly lower than last year's 10-year forecast (SERC-E-Table 2). Most entities are not expecting significant change in growth. However, differences are accounted for through lower load projections. Entities in the area have experienced a shift in load-serving responsibilities among entities in the area due to contractual agreements scheduled between 2013 and 2019.

SERC-E-Table 2: Demand Outlook

SERC-E-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	41,805	46,386	4,581	11.0%	1.16%
Load-Modifying Demand Response	1,928	2,311	383	19.9%	2.03%
TOTAL INTERNAL DEMAND	**43,733**	**48,697**	**4,964**	**11.4%**	**1.20%**

SERC-E-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	42,042	46,730	4,688	11.2%	1.18%
Load-Modifying Demand Response	1,540	1,665	125	8.1%	0.87%
TOTAL INTERNAL DEMAND	**43,582**	**48,395**	**4,813**	**11.0%**	**1.17%**

Some entities in the reporting area are currently assessing their forecasting models for the most recent regional and local economic projections. This information will come from vendors such as Economy.com and IHS Global Insight. Weather projections were taken from various sources, such as the National Oceanic and Atmospheric Administration (NOAA), or individual company databases. Projections in this reporting area are expected to be normal. However, energy sales projections, which serve as a primary driver of the load forecast for some entities, are lower based on revised economic growth assumptions. No other significant changes or enhancements were reported for this year's forecasting methods.

Demand-Side Management

Demand Response and Energy Efficiency is projected to be 1,928 MW and 581 MW respectively for the 2013 reporting period.

Approximately 2,310 MW of Demand Response and 299 MW of Energy Efficiency are projected to be available on-peak by 2022. These programs are used to reduce the effects of period peaks and are considered part of the utilities' resource planning. Demand Response is projected to account for 4.40 and 4.75 percent of Total Internal Demand in 2013 and 2022, respectively. Demand Response is projected to increase to 1,928 MW in 2013. Additionally, Energy Efficiency is projected to account for 0.70 and 2.97 percent of Total Internal Demand for 2013 and 2022, respectively (SERC-E-Table 3). Projections are intended to reduce peak demand on entity systems within the reporting area.

SERC-E-Table 3: Projected Demand-Side Management

	Short-Term					
SERC-E-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	858	969	1,064	1,201	343	2.47%
Contractually Interruptible (Curtailable)	967	968	981	1,002	35	2.06%
Critical Peak-Pricing (CPP) with Control	14	19	19	19	5	0.04%
Load as a Capacity Resource	89	89	89	89	0	0.18%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,928	2,045	2,153	2,311	383	4.75%
TOTAL ENERGY EFFICIENCY	299	375	549	1,444	1,146	2.97%
TOTAL DEMAND-SIDE MANAGEMENT	**2,227**	**2,420**	**2,702**	**3,755**	**1,529**	**7.71%**

Entities continue to assess the effects of newly approved Energy Efficiency programs installed on the system since 2010. However, a variety of existing programs that support Energy Efficiency and Demand Response are also offered to customers in this reporting area. Some of the programs that include current Energy Efficiency and DSM programs are interruptible capacity programs, load control curtailing programs, residential air conditioning direct loads programs, energy products loan programs, standby generator controls programs, residential time-of-use programs, Demand Response programs (interruptible and related rate structures), Power Manager Power Share conservation programs, residential Energy Star rates programs, the Good Cents new home program, the commercial Good Cents program, the thermal storage cooling program, the H20 Advantage water heater program, general service and industrial time-of-use programs, and hourly pricing for incremental load interruptible programs. They are also used to reduce the effects of period peaks and are considered

part of the utilities' resource planning. The commitments to these programs are part of a long-term, balanced energy strategy to meet future energy needs. Load response will be measured by trending real-time load data from telemetry and statistical models that identify the difference between the actual consumption and the projected consumption absent the curtailment event. As stated above, entities include renewables in their portfolios to meet the requirements of the REPS of North Carolina.

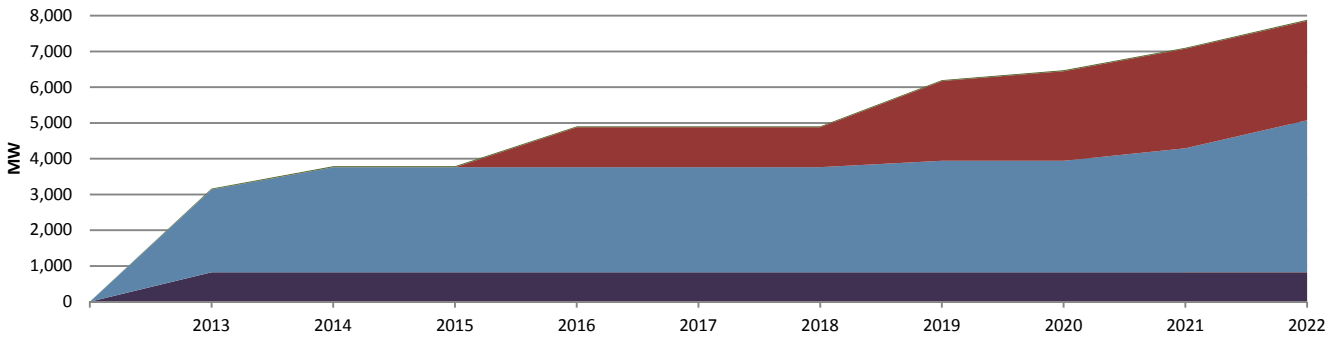
Generation

Companies within the SERC-E reporting area expect to have 48,218 MW of Existing-Certain, 0 MW of Existing-Other, 0 MW of Existing-Inoperable, 3,167 MW of Future-Planned, and 14 MW of Conceptual resources on-peak for 2013. Additionally, 7,888 MW of Future-Planned resources and 14 MW of Conceptual resources are expected to be added in 2013. This capacity is projected to help meet demand during this time period. Coal is the primary source of fuel within this area. Entities have added the 20 MW of Biomass and 5 MW of Solar Existing-Certain resources since the previous long-term reporting period (SERC-E Table 5 and SERC-E Figure 3). However, entities have reported 656 MW of unit retirements since the previous long-term reporting period. Additionally, 1,191 MW of unit retirements have been reported to occur during the 2013 to 2022 period (SERC-E-Table 4 and SERC-E-Figure 2). Internal company discussions of these retirements have included mitigation measures that must be explored and considered as part of any decision to retire existing generating units. This capacity will be offset in part by the addition of 4,251 MW of combined-cycle units by 2022 and 2,234 MW of nuclear generation (1,117 MW in 2016 and 2019).

SERC-E-Table 4: Capacity Outlook[251]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-E-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	16,775	34.8%	17,600	31.4%	825	17,600	31.3%	825
Petroleum	1,967	4.1%	1,967	3.5%	0	1,967	3.5%	0
Gas	11,682	24.2%	15,934	28.4%	4,252	15,934	28.4%	4,252
Nuclear	11,456	23.7%	14,242	25.4%	2,786	14,242	25.4%	2,786
Other/Unknown	107	0.2%	107	0.2%	0	107	0.2%	0
Renewables	6,256	13.0%	6,281	11.2%	25	6,295	11.2%	39
TOTAL	**48,243**	**100.0%**	**56,131**	**100.0%**	**7,888**	**56,145**	**100.0%**	**7,902**

SERC-E-Figure 2: Summer Net Capacity Change



There are no new generator uprates in service, and no generation taken out of service for maintenance during the period. SERC methods of data collection do not identify specific uprates or derates throughout the year. Rather, entities reporting to SERC make changes to unit generation continuously throughout the year. Additionally, there is no behind-the-meter generation reported for the period. However, 387 MW of Other/Unknown resources and 200 MW of capacity from standby generator programs and interruptible services are anticipated during this time.[252]

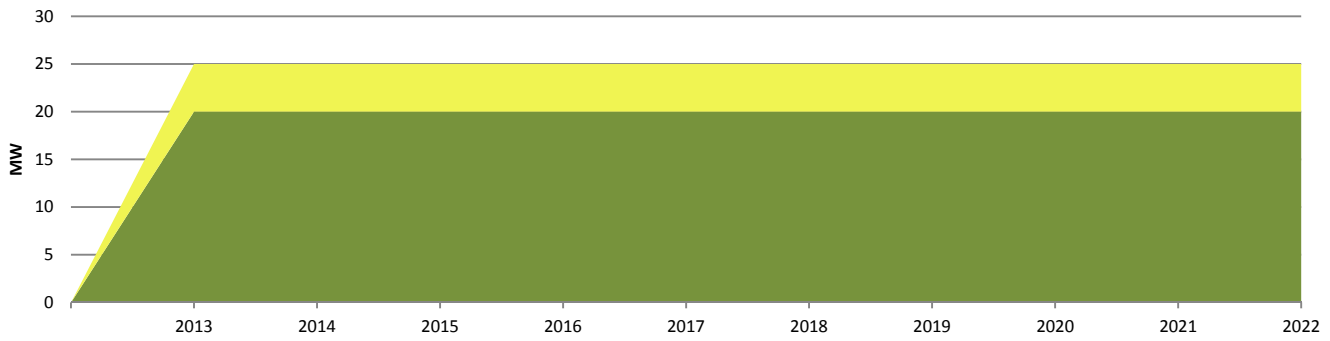
[251] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[252] Includes resources categorized as Existing-Other, which are not included in the above table.

SERC-Table 5: Renewable Capacity Outlook[253]

SERC-E-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Hydro	3,087	49.3%	3,087	49.1%	0	3,087	49.0%	0
Pumped Storage	3,044	48.7%	3,044	48.5%	0	3,044	48.4%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	0	0.0%	0	0.0%	0	0	0.0%	0
Biomass	97	1.5%	117	1.9%	20	127	2.0%	30
Solar	28	0.5%	33	0.5%	5	37	0.6%	9
TOTAL	**6,256**	**100.0%**	**6,281**	**100.0%**	**25**	**6,295**	**100.0%**	**39**

SERC-Figure 3: Net Renewable Capacity Change



Variable resources are limited within this area and are not commonly planned in peak maximum capacity calculations. However, they are assessed for their availability to meet the needs of customers reliably and economically, based on the requirements of the regulatory standards and their ability to maintain flexibility for long-term resource decisions. These resources may be given a reduced capacity contribution for Reserve Margin based on an estimated hourly energy profile (SERC-Table 6). As required, entities will continue to evaluate these and other renewable resources as part of its integrated resource planning process. In addition, no immediate changes in entity planning procedures are needed. This is due to adding small increments of variable resources yearly to meet the REPS 12.5 percent target by 2021.

SERC-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

SERC-E-Summer	Current Wind	Current Solar	Current Hydro	Current Biomass	2022 Planned Wind	2022 Planned Solar	2022 Planned Hydro	2022 Planned Biomass
Installed Capacity	0	28	3,087	97	0	33	3,087	117
On-Peak Derate	0	0	0	0	0	0	0	0
EXPECTED ON-PEAK OUTPUT	0	28	3,087	97	0	33	3,087	117

Capacity Transactions

Utilities within the SERC-E reporting area expect the capacity imports and exports listed in the table below (SERC-E-Table 7). These transactions have been accounted for in the Reserve Margin calculations for the reporting area. Most of the contracts in the area are agreements for a 10-year period for the winter and summer peaking seasons. These transactions are external and internal to the Region and the reporting area. All purchases are backed by Firm contracts for both generation and transmission and are not considered to be based on partial path reservations. Of the imports/exports shown below, very few are associated with Liquidated Damages Contracts (LDCs), in which the contracts are considered 100 percent "make-whole."

[253] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

SERC-E-Table 7: Projected Capacity Transactions

SERC-E	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	1,003	815	815	715	760	760	850	850	850	850
TOTAL IMPORTS	1,003	815	815	715	760	760	850	850	850	850
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	117	167	167	167	167	167	167	167	167	67
TOTAL EXPORTS	117	167	167	167	167	167	167	167	167	67
TOTAL NET CAPACITY TRANSACTIONS	**886**	**648**	**648**	**548**	**593**	**593**	**683**	**683**	**683**	**783**

To meet Reserve Margins during the period, entities within the SERC-E reporting area do not rely on resources outside the Region for emergency imports, reserve sharing, or outside assistance/external resources. Most entities within this area participate in reserve sharing agreements (RSAs) with other VACAR utilities. Collectively, members of the VACAR RSA, under their current agreement, hold 1.5 times the largest single contingency (1,135 MW) in the VACAR RSA Area to meet Reserve Margin targets. The Reserve Sharing Group is expected to have adequate reserves throughout the operating period. Total emergency MW from these imports was not reported but are available as needed.

Transmission

In-service dates for existing transmission projects are not at risk during the reporting period. If delays occur that would result in reliability concerns, mitigating actions would be developed accordingly. Mitigating measures include re-dispatch of generation, operating procedures, and Special Protection Systems. On an ongoing basis, companies review/confirm completion dates and monitor the construction status of all projects. Transmission projects planned to address a potential System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) problem commonly receive the highest priority for resources. A summary of existing and projected transmission additions is included below (SERC-E-Table 8)

SERC-E-Table 8: Existing and Projected Transmission

SERC-E	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	22,180	0	22,180
Currently Under Construction	33	0	33
Planned - Completed within First Five Years	276	0	276
Planned - Completed within Second Five Years	189	0	189
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	22,678	0	22,678
Conceptual - Completed within First Five Years	87	0	87
Conceptual - Completed within Second Five Years	189	0	189
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**774**	**0**	**774**

New construction efforts are focused on completing facilities ahead of seasonal peak periods. Close coordination between construction management and operations planning ensures schedule requirements and completion requirements are well-understood. Several large-scale construction projects are planned and will be implemented in phases around seasonal peak load periods to mitigate reliability concerns associated with line clearances and non-routine operating arrangements during higher seasonal load periods. Additionally, no significant transmission facility outages are anticipated to be out of service during the period.

Regional studies are also performed on a routine basis both internally and externally. Coordinated single transfer capability studies with external utilities are performed quarterly by the SERC Near-Term Study Group (NTSG). Projected seasonal import and export capabilities are consistent with those identified in these assessments. Constraints that are external to the SERC subregion are evaluated as part of the SERC East-RFC Seasonal Study Group efforts. No transmission constraints have been identified that are anticipated to significantly impact reliability.

To address the need to maintain and enhance reliability, Progress Energy Corporation (PEC) is currently implementing a special transmission project in response to NERC's recommendation to utilities entitled "Consideration of Actual Field Conditions in Determination of Facility Ratings." The entity is using Light Detection and Ranging, (LiDAR) technology to analyze these conditions. Results from the project are currently being assessed, and the project is scheduled to be completed by the end of 2014. Any concerns that are identified will be mitigated through an immediate remediation strategy.

Other Transmission Operators in the SERC-E reporting area are also subject to the NERC recommendation. None report any negative transmission reliability or adequacy concerns.

Shifts from the use of coal to natural gas as a generation fuel source due to decreasing costs of natural gas have led to non-typical transmission line power loadings. However, none of the Transmission Operators in the SERC-E reporting area report any negative impact on transmission adequacy. Entities will continue to consider new Demand-Side Management tools, SVC technology, and potential applications of smart grid technology.

Vulnerability Assessment

Resource adequacy studies help determine entity Reserve Margins in the reporting area. The study recognizes, among other factors (such as load forecast uncertainty due to economics and weather), generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. Uncertainties may also be addressed through capacity margin objectives and practices in other resource assessments at the operational level. These studies may be performed annually using input provided from Generator Operators. As conditions warrant, entities may see the need to perform additional assessments to mitigate challenging conditions on the system. Entities report that historical studies have determined that a minimum Planning Reserve Margin of 12 percent is adequate for reliability. The latest studies have identified that future generation is needed to achieve planning adequate reserves. Entities will account for this in their long-term generation plans. Plans will also account for new environmental requirements, renewable energy, new generation technologies, and rising commodity costs. No other concerns are known at this time, and operational problems are not anticipated for the period.

Additionally, a study was done on the eastern North Carolina coastal area (Jacksonville, Havelock, and Morehead City) that resulted in a long-term project to install a large Static Var Compensator at the Jacksonville 230 kV substation. Similarly, another dynamic study was recently performed in the western area of North Carolina that validated the existing procedure to operate a minimum complement of generators at various load/import levels to ensure adequate dynamic reactive resources are available for this area.

In order to address reliability issues in the future, utilities have considered using Under-Voltage Load Shedding (UVLS) schemes on their system. However, none of these programs are expected to be installed on the system during the time of this assessment. Additionally, there are no Special Protection Systems or Remedial Action Schemes within SERC-E and none planned for the assessment period.

Utilities have addressed planning processes for catastrophic events in many ways. Some companies have procedures in place for system restoration, as well as capacity and emergency action plans. Other companies follow the practice of maintaining several days' worth of fuel oil at facilities in the event of natural gas disruptions. Resource portfolios are also used to address the issue. Portfolios are diversified with multiple resources mitigating the impact of a major import path disruption. Sophisticated internal real-time systems have been developed by the utilities within the reporting area to track and analyze gas pipeline issues. These systems can monitor the impact of disruptions to major pipelines or the loss of a major import path as part of a contingency analysis process. Depending on the advance notice, either operating plans can be adjusted or emergency procedures can be implemented. For the projected summer peaks, Reserve Margins are such that the loss of multiple units can be accommodated without threatening reliability. Purchased power sources utilize Firm transmission and are sufficiently limited in quantity compared to total resources. The VACAR reserve-sharing agreement is also available to support recovery from such extreme events. Beyond these measures, transmission Reserve Margin can also be utilized to secure market purchases to maintain reliability.

The utilities within SERC-E have procedures in place to identify and review misoperations caused by protection systems. When a misoperation occurs on the transmission system, corrective action is implemented to prevent recurrence. If needed, other locations are also reviewed for problems of a similar nature. Misoperations caused by protection systems are reviewed on an annual basis for possible trends.

Currently, utilities in the area are not aware of any environmental or regulatory restrictions that could impact reliability during the reporting period. They will continue to assess system studies and develop generation mitigation plans as needed to account for new environmental requirements.

Standing and Emerging Reliability Issues

To minimize reliability concerns on the system, entities regularly study and review annual and seasonal assessments. These assessments serve to develop a seasonal strategy for maintaining adequate system operating performance. Entities are also active participants within the SERC NTSG, which regularly performs annual reliability studies for summer and winter peak conditions, as well as quarterly OASIS studies for summer, fall, winter, and spring conditions. Transmission maintenance schedules are carefully reviewed and evaluated to address reliability concerns, and to permit as much prioritized maintenance as can be accommodated prior to seasonal peak periods. Likewise, new construction efforts are focused on completing facilities ahead of seasonal peak periods. Annual planning activities continue to address both near- and long-term facility needs.

Overall, there are no known or projected significant conditions or generator outages that would reduce capacity in the area. Entities in the SERC-E reporting area are not aware of any near-term environmental or regulatory restrictions that could impact reliability and continue to assess the potential reliability effects of pending future environmental regulations.

The utilities in the SERC-E Area have identified an emerging issue in regard to Fault Induced Delayed Voltage Recovery (FIDVR), which is the phenomenon whereby system voltage remains at significantly reduced levels for several seconds after a transmission, sub-transmission, or distribution fault has been cleared. Significant load loss due to motor protective device action can result, as can significant loss of generation, with a potential secondary effect of high system voltage due to load loss. If the BES voltage does not recover to 90 percent of the pre-contingency system voltage in a few seconds, the FIDVR can initiate further tripping of load and generation. Longer periods of depressed voltage below such levels can cause damage to customer and electric system equipment.

Planning studies have not been able to foresee FIDVR events very accurately due to an inaccurate modeling of loads. Uncorrected, this modeling deficiency has a two-fold detrimental effect. First, it can result in studies that do not adequately identify potential FIDVR events. Second, it can give false confidence in mitigation plans designed to prevent FIDVR events. Several groups of experts are actively developing better dynamic load models for aggregate induction motor load using results of extensive single-phase air conditioning performance tests and detailing analyses of actual FIDVR events. Although SERC-E has not experienced a significant reliability impact associated with FIDVR, some utilities in SERC-E have already installed SVCs (or plan to) as a mitigating measure for potential FIDVR issues.

SERC-N

Planning Reserve Margins

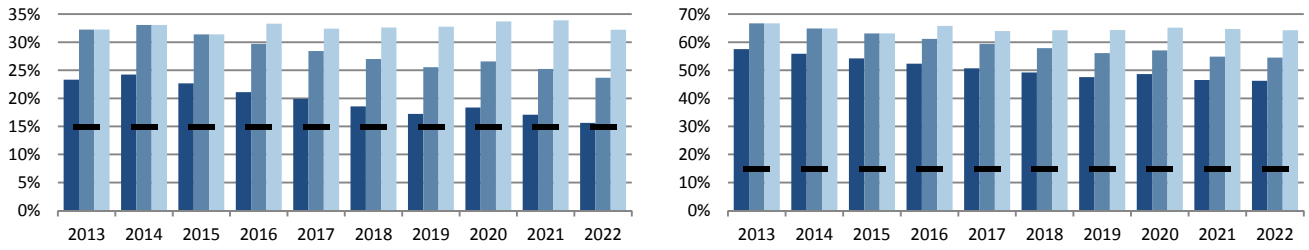
As a result of lower loads in the first few years, coupled with additional capacity, the SERC-N Assessment Area is projecting adequate Anticipated Planning Reserve Margins ranging between 15.63 and 24.23 percent during the assessment period (SERC-N-Table 1 and SERC-N-Figure 1).

SERC-N-Table 1: Planning Reserve Margins

SERC-N-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		23.31%	24.23%	22.67%	21.09%	19.91%	18.57%	17.21%	18.36%	17.10%	15.63%
PROSPECTIVE		32.26%	33.06%	31.39%	29.70%	28.43%	27.00%	25.54%	26.58%	25.23%	23.66%
ADJUSTED POTENTIAL		32.26%	33.06%	31.39%	33.31%	32.41%	32.61%	32.75%	33.70%	33.89%	32.21%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-N-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		57.56%	55.86%	54.21%	52.37%	50.71%	49.23%	47.57%	48.63%	46.52%	46.24%
PROSPECTIVE		66.69%	64.89%	63.14%	61.19%	59.44%	57.88%	56.11%	57.08%	54.85%	54.51%
ADJUSTED POTENTIAL		66.69%	64.89%	63.14%	65.77%	63.97%	64.27%	64.32%	65.20%	64.69%	64.28%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-N-Figure 1: Summer (Left) and Winter[254] (Right) Planning Reserve Margins



SERC does not require specific Reserve Margin criteria or "targets" for SERC-N. Therefore, NERC applies the 15 percent Reference Margin Level throughout the assessment period. Additionally, some individual entity criteria are established based on state public service commissions or their Balancing Authority's criteria, such as most severe single contingency, cost of unserved energy, unit availability, import availability/capability, load forecast, and loss of load probability studies (such as 0.1 day per year). Other utilities report that Planning Reserve Margins are established with the objective of minimizing overall cost of reliability to the customer, while not exposing customers to significant risk. To achieve this goal, planning reserves are calculated on a probabilistic assessment of reliability, which includes uncertainty related to weather, economic growth, unit availability, and transmission capability to determine expected costs at various levels of reliability. Using this analysis, a target level of planning reserves is selected such that the cost of additional reserves plus the cost of reliability events to the customer is minimized. This target (optimal) Reserve Margin is then adjusted to reduce risks and enhance reliability to produce the final level of planning reserves. Entities internally report planning reserves in the range of 12 to 15 percent during the assessment period.

Assessment projections are anticipated to be adequate, assuming typical weather and operating conditions. Given these circumstances, no significant detractions from this forecast are anticipated.

Demand

The Total Internal Demand in SERC-N is projected to grow by approximately 1.44 percent during the 10-year assessment. This growth is slightly higher compared to the 2011 forecast (SERC-N-Table 2).

[254] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

SERC-N-Table 2: Demand Outlook

SERC-N-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	43,808	48,778	4,970	11.3%	1.20%
Load-Modifying Demand Response	1,942	3,260	1,318	67.9%	5.92%
TOTAL INTERNAL DEMAND	**45,750**	**52,038**	**6,288**	**13.7%**	**1.44%**

SERC-N-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	43,734	48,256	4,522	10.3%	1.10%
Load-Modifying Demand Response	1,979	3,658	1,679	84.8%	7.06%
TOTAL INTERNAL DEMAND	**45,713**	**51,914**	**6,201**	**13.6%**	**1.42%**

Increases are believed to be primarily due to a perception of improved economic outlook. However, continuing low economic forecasts and growing levels of Demand Response and Energy Efficiency programs are expected to limit demand growth in the coming years. Assumptions have been adjusted for normal weather and current economic conditions for both the United States and regional economies. Since the start of the economic recession, some entities have significantly adjusted their long-term models and revised their near-term hourly forecast models.

Demand-Side Management

Demand Response and Energy Efficiency are projected to be 1,942 MW and 149 MW, respectively, available on-peak for the 2013 reporting period, increasing to approximately 3,260 MW of Demand Response and 516 MW of Energy Efficiency by 2022 (SERC-N-Table 3). The Demand Response and Energy Efficiency average annual growth rates for the 2013–2022 reporting period are 7.5 percent and 27.4 percent respectively. Demand Response programs allow entities within the reporting area to reduce demand and control voltage as needed for reliability purposes, mainly during summer peaks. Demand Response is projected to account for 4.2 percent of Total Internal Demand in 2013, a substantial increase from 0.3 percent in 2011. Presently the primary source of Demand Response in the area is the direct load control (DLC) program and the interruptible product portfolio. DLC includes a program with interruptible load contracted to a third party and verified by the utility. Program participants have contractually agreed to reduce their loads within minutes of a request. Estimates used in operational planning take into account the amount of load available and not the sum of total load under contract. Other Demand Response products utilize control devices on air conditioning units and water heaters in residences. Entities are planning for increased demand reductions from the following in the upcoming years: interruptible demand and load control capabilities, distributor-operated voltage regulation programs, Demand Response pricing products, and two-way direct load control.

SERC-N-Table 3: Projected Demand-Side Management

	Short-Term					
SERC-N-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	194	204	221	137	-57	0.26%
Contractually Interruptible (Curtailable)	992	1,000	1,003	1,003	11	1.93%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	756	951	1,127	2,120	1,364	4.07%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,942	2,155	2,351	3,260	1,318	6.26%
TOTAL ENERGY EFFICIENCY	149	199	243	516	367	0.99%
TOTAL DEMAND-SIDE MANAGEMENT	**2,091**	**2,354**	**2,594**	**3,776**	**1,685**	**7.26%**

New Energy Efficiency is projected to be 0.3 percent of Total Internal Demand during 2013 and increase to 1.0 percent by 2022. Programs such as customer cost-saving energy surveys and audit evaluations, customer education, responsive pricing, residential/commercial conservation, electric thermal storage incentives, new construction (heat pump and geothermal), energy efficient homes, air-source heat-pumps (replacing older resistance heat), low-income weatherization, low-income assistance, HVAC system improvements, industrial compressed-air systems, and various advanced lighting and third-party verification/measurement groups are currently in operation within the area for residential and commercial customers. Commercial/industrial/direct-served industry consumers have programs for efficiency improvements in HVAC, lighting, motors and controls, and other electrical-intensive equipment. Entities in the area are predicting an additional 1,400 MW of controllable Demand Response reductions by the end of 2012.

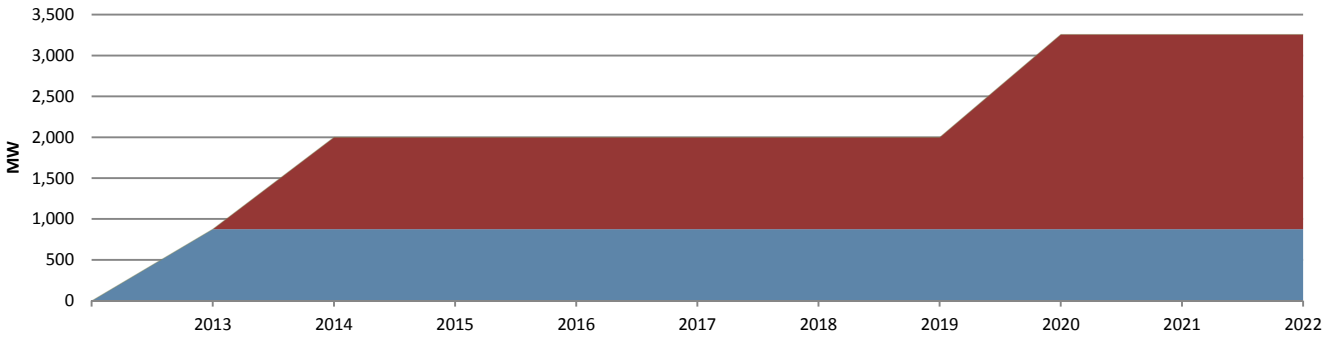
Generation

Companies within SERC-N expect to have 53,084 MW of Existing-Certain, 3,919 MW of Existing-Other, 0 MW of Existing-Inoperable, 878 MW of net Future-Planned resources including retirements, and 0 MW of Conceptual resources on-peak for 2013. Net Future-Planned resources of 3,260 MW and Conceptual resources of 4,170 MW are expected to be added by 2022. Coal is the primary source of fuel within this area. There are no new Existing-Certain Resource additions since the prior season. For 2012, 71 MW is planned to be on inactive reserve, 412 MW is scheduled to be on 8 weeks of planned maintenance beginning the first week of September, 167 MW is scheduled to be on planned maintenance for the last week of September, and 352 MW will be retired. A total of 3,021 MW of retirements have been announced for the 2013–2022 reporting period. In accordance with an EPA settlement, four units (approximately 480 MW) are scheduled to idle in the spring of 2012[255] and retire by the end of 2015; six units (111 MW each) will be out of service by August 1, 2015; 2,078 MW will be retired in 2016, and 938 MW will be retired in 2019 (SERC-N-Table 4, SERC-N-Figure 2, and SERC-N-Table 5). The ability for utilities to reliably meet demand is not expected to be impacted by these planned retirements. Scenario planning studies are routinely done to assess the impact on system reliability and adequacy for possible unit retirements during the planning window. The results of those studies are used in the annual planning process and as input to the ongoing development of generating fleet strategic plans. Planning actions in response to the retirements include consideration of additional resource needs in Integrated Resource Plans, reinforcement of the transmission system including uprating a number of lines, and evaluation of needs for static and dynamic var support, such as for major cities with high concentrations of air conditioning load.

SERC-N-Table 4: Capacity Outlook[256]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-N-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	21,657	40.1%	21,657	37.8%	0	21,657	35.3%	0
Petroleum	111	0.2%	111	0.2%	0	111	0.2%	0
Gas	18,060	33.5%	18,938	33.1%	878	23,108	37.6%	5,048
Nuclear	7,113	13.2%	9,495	16.6%	2,382	9,495	15.5%	2,382
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	7,022	13.0%	7,022	12.3%	0	7,022	11.4%	0
TOTAL	**53,962**	**100.0%**	**57,222**	**100.0%**	**3,260**	**61,392**	**100.0%**	**7,430**

SERC-N-Figure 2: Summer Net Capacity Change



There are 2 MW of new generator uprates scheduled to be in service. However, 20 MW are scheduled to be taken out of service for planned maintenance during the peak demand months of 2012, and 6 MW will be brought back in service yearly for the peak-demand summer months of 2013–2015. As an average over the period, behind-the-meter generation is reported to be 13 MW of Other/Unknown resources.

[255] http://www.epa.gov/compliance/resources/cases/civil/caa/tvacoal-fired.html

[256] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

SERC-N-Table 5: Renewable Capacity Outlook[257]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-N - Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	5,325	75.8%	5,325	75.8%	0	5,325	75.8%	0
Pumped Storage	1,652	23.5%	1,652	23.5%	0	1,652	23.5%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	28	0.4%	28	0.4%	0	28	0.4%	0
Biomass	17	0.2%	17	0.2%	0	17	0.2%	0
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**7,022**	**100.0%**	**7,022**	**100.0%**	**0**	**7,022**	**100.0%**	**0**

Variable resources are limited within this area. However, there are some purchases sourced from wind that are included in the transfer amount and a small amount of solar supply that is part of a customer-owned generation buy-back program. The capacity values of wind contracts are usually based on applicable contract terms (SERC-N-Table 6).

SERC-N-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
SERC-N-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	179	0	5,325	17	179	0	5,325	17
On-Peak Derate	152	0	0	0	152	0	0	0
EXPECTED ON-PEAK OUTPUT	28	0	5,325	17	28	0	5,325	17

A typical assumed contribution at the time of the system peak is 12 percent of the nameplate ratings of the associated wind generators (this factor is consistent with the credit applied by RTOs to other wind resources in that same geographical area). The contribution from customer-owned solar resources is based on the solar insolation values for the area at the time of the period peak. Entities will continue to evaluate these and other renewable resources as part of their integrated resource planning processes. No changes in planning procedures are needed for these small increments of variable resources.

Capacity Transactions

Utilities within SERC-N expect the imports and exports listed below for the period. These imports and exports have been accounted for in the Reserve Margin calculations for the reporting area. Most of the contracts in the area are agreements for a 10-year period for the winter and peaking seasons. The majority of these imports/exports are backed by Firm contracts for both generation and transmission, and do not include "make-whole provisions." However, more than half of the imports reported by entities within SERC-N during the peak month are not backed by a Firm contract. Non-Firm contracts are not included in SERC-N Planning Reserve Margins. Total imports and exports will remain constant throughout the assessment period at 1,640 MW and 1,582 MW, respectively (SERC-N-Table 7)

SERC-N-Table 7: Projected Capacity Transactions

SERC-N - Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333
Firm Imports	307	307	307	307	307	307	307	307	307	307
TOTAL IMPORTS	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Expected Exports	156	156	156	156	156	156	156	156	156	156
Firm Exports	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
TOTAL EXPORTS	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582
TOTAL NET CAPACITY TRANSACTIONS	**58**	**58**	**58**	**58**	**58**	**58**	**58**	**58**	**58**	**58**

Contingency reserves and emergency imports are obtained from a variety of resources, such as Midwest ISO (under Attachment RR of the Midwest ISO ancillary services market tariff), PJM, and the TVA-EKPC-E.ON.US Contingency Reserve Sharing Group (TCRSG). The TCRSG consists of three Balancing Authorities that are internal to the area and is intended to provide immediate response to contingencies. This assists the group with complying with the Disturbance Control Standard (DCS) and preventing the curtailment of native load. Even though some entities rely on outside resources for imports, there are others within the area that do not depend on short-term outside purchases or transfers from other regions or reporting areas to meet demand requirements. Purchase agreements for imports do not include emergency MW arrangements.

[257] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Transmission

Two significant transmission projects in the SERC-N Area are Blackberry–Sportsman Acres (in service in 2013) and Franks–Barnett (in service in 2016). Currently, there are no major concerns with meeting in-service dates for transmission improvements or specific projects needed to maintain reliability. Additionally, there is adequate transmission to support the reported Future-Planned generation. If necessary, local area generation may be re-dispatched or transmission elements reconfigured to alleviate next contingency overloads. Entities also have the option to invoke NERC Transmission Limited Resource (TLR) procedures in scenarios that are not easily remedied by a local area solution. A summary of existing and projected transmission additions is included below (SERC-N-Table 8).

SERC-N-Table 8: Existing and Projected Transmission

SERC-N	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	21,600	0	21,600
Currently Under Construction	254	0	254
Planned - Completed within First Five Years	332	0	332
Planned - Completed within Second Five Years	13	0	13
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	22,198	0	22,198
Conceptual - Completed within First Five Years	21	0	21
Conceptual - Completed within Second Five Years	57	0	57
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**676**	**0**	**676**

Entities in the area continue to evaluate and consider new technologies that can be utilized to improve BPS reliability. An example of this is TVA's Clay, Mississippi, a fourth-generation GIS 500/161 kV substation, which is scheduled to be placed in service prior to the 2012 summer peak. This project will provide enhanced reliability for load in the vicinity.

Vulnerability Assessment

Resource adequacy assessments covering the next 36 months are performed monthly to assist in identifying limitations or constraints that may impact seasonal adequacy. Long-term adequacy assessments based on 20-year capacity plans are also performed to make decisions relative to resource acquisitions, renewable portfolio standard legislations, and project development timelines to ensure system reliability. No system reliability concerns for the period have been identified in the latest resource adequacy studies. Resource availability, fuel availability, and hydro and reservoir conditions are expected to be normal during the period. In addition, there are no issues due to the distribution of generation or the unavailability of Demand Response. The contributions of Demand Response programs are included in long-range capacity planning studies. Programs are based on the particular program impact, historical trends of effectiveness in the region, dependability, and system cost-effectiveness, for use in summer peak adequacy assessments. Entities are monitoring adjustments and results to these studies as a consequence of new and potential environmental regulations.

No additional UVLS schemes are planned for installation during the assessment period, but TVA is considering an additional scheme in addition to two existing UVLS protection schemes already in place to limit potential wider area under-voltage events. The non-coincident peak demand served from the substations equipped with UVLS totals approximately 450 MW. No Special Protection Systems or Remedial Action Schemes are planned for the time period.

Entities regularly participate in emergency system drills to ensure that operators are trained and properly prepared for catastrophic events. The transmission planning processes prepare for the loss of up to all units at any given generating station as part of assessments. Planners disseminate that information to system operations. Entities also rely on reserve sharing, Purchasing and Selling Entities (PSEs), and coordination with Balancing Authorities, through capacity and energy emergency plans. Planned unit maintenance outages or derates may be delayed or canceled in the event of a significant loss in capacity, and voluntary load shedding and energy emergency criteria will be enacted if necessary.

Some entities use risk analysis processes to identify the contingencies that have the greatest impact on their resource adequacy over the long term. Specific outage events are not modeled in that analysis but may be considered during sensitivity studies as part of the annual capacity planning effort. If resource inadequacies (such as catastrophic events) cause the Reserve Margin to be reduced, the entity then may anticipate the use of purchases from the short-term markets as a necessary addition to appropriate operational actions to ensure system reliability.

For the operational planning horizon, in the event of a catastrophic event such as a hurricane causing pipeline outages, supply/transportation could be re-routed to other pipeline legs (routes), thereby bypassing the restriction or outage. Entities also have backhaul transportation contracts in place that could be utilized to source and deliver supply. If a storage facility allows, supply could be wheeled (an interruptible service) across the storage facility to other pipeline interconnects.

Most smart grid efforts to date have been on the scale of demonstration projects. A summary of TVA's current research and programs can be found on TVA's web site.[258] LG&E and KU Energy plans to invest approximately $14 million in smart grid enabling technologies by 2014. These investments provide for a variety of enhanced capabilities for system monitoring and operation. No reliability improvements or issues have been identified as a direct result of these investments.

Entities have established proactive programs to minimize the likelihood of relay protection misoperations. Recent evaluations have revealed problems with increases in 'unknown' causes, carrier failure, calculations and settings, and relay applications. Remedial measures include maintenance programs to periodically calibrate and test relays, investigations of every relay misoperation, goals to remedy misoperations within two years, relay replacement programs to replace obsolete relays, improved implementation processes, and improved identification of mutual coupling effects.

Utilities in the area are aware of the potential for environmental/regulatory restrictions to impact generating resource operations. These can include emissions restrictions as well as cooling water source temperature regulation, which can lead to plant derates. Routine internal communications practices will alert operational planners at the onset to any potential environmental/regulatory impact to plant operations. Such limitations are factored into operational planning analysis.

There are currently no anticipated unit retirements that significantly impact system reliability, nor any indication that there will be insufficient time to perform any required retrofits. Entities will continue to conduct scenario planning studies to assess the impact on system reliability and adequacy for possible unit retirements during the period. The results of those studies are used in annual planning and provide input to ongoing development of generation fleet strategic plans. The effects of possible future long-term maintenance outages on off-peak reliability are uncertain. Ongoing mitigation plans are developed to reduce system reliability risks. Mitigations may include purchases, new generation, or reliance on reserves. However, for every new regulation that is promulgated, entities will continue to adapt their operations as needed (e.g., install controls, etc.) such that they comply with new regulatory requirements and do not affect reliability.

Standing and Emerging Reliability Issues

As stated in the previous section, utilities are aware of the risks associated with the current and pending environmental regulations/limitations and have established operational procedures to avoid or mitigate system reliability impact. Long-term adequacy assessments based on 20-year capacity plans are performed to make decisions relative to resource acquisitions and project development timelines to ensure system reliability. Resource adequacy assessments covering the next 36 months are performed monthly to assist in identifying limitations or constraints that may impact seasonal adequacy. Entities monitor adjustments and results to the studies as a consequence of environmental regulations.

Ongoing mitigation plans are developed to reduce system reliability risks. Mitigations may include purchases, new generation, or reliance on reserves. However, as for every regulation, entities will continue to adapt their operations as needed (e.g., install controls, etc.) such that they comply with new regulatory requirements and do not affect reliability.

There are currently no anticipated unit retirements that significantly impact system reliability, nor any indication that there will be insufficient time to perform any required retrofits. Entities will continue to conduct scenario planning studies to assess the impact on system reliability and adequacy for various assumptions of possible unit retirements during the period. The results of those studies are used in annual planning and provide input to ongoing development of generation fleet

[258] http://www.tva.gov/environment/technology/epri.htm.

strategic plans. The effects of possible future, long-term maintenance outages on off-peak reliability are believed to be negligible.

Utilities within the SERC-N Area have experienced two reliability issues: severe weather-related damage such as that caused by the very severe tornadic activity in April 2011; and the effects of substantial reconstruction efforts required after a significant event occurs. While severe weather-related damage is a standing issue for the SERC-N Area, the reconstruction efforts are an emerging issue. No long-term reliability impact is expected due to the storm damage from the spring storms. The assessment impact is generally the same for both reliability issues.

Severe weather events are generally unpredictable, and two or more such events could lead to uncertainty in the ability to maintain adequate reserves. The unprecedented April 2011 storm events in SERC-N removed from service and damaged approximately 90 TVA transmission lines. Such widespread damage can challenge reserves of restoration materials.

In recent years, utilities within the reporting area have experienced pressure in maintaining margin reserves due to restoration activities, maintenance schedules, high-water threats from the Mississippi River, and hot weather.

SERC-SE

Planning Reserve Margins

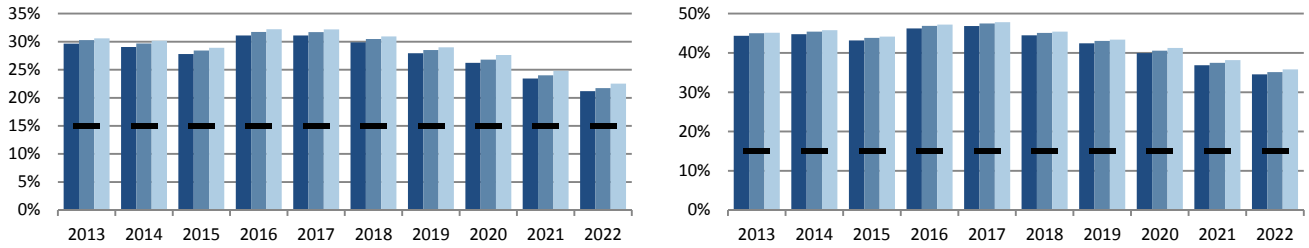
During the assessment period, the SERC-SE Assessment Area is projecting adequate Anticipated Capacity Resource Reserve Margins falls as low as 21.18 percent in the final year of the assessment period, above the NERC Reference Margin Level (SERC-SE-Table 1).

SERC-SE-Table 1: Planning Reserve Margins

SERC-SE-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		29.66%	29.06%	27.80%	31.12%	31.11%	29.88%	27.94%	26.22%	23.44%	21.18%
PROSPECTIVE		30.29%	29.68%	28.41%	31.72%	31.70%	30.47%	28.52%	26.79%	24.01%	21.74%
ADJUSTED POTENTIAL		30.58%	30.17%	28.90%	32.20%	32.18%	30.94%	28.99%	27.61%	24.81%	22.53%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-SE-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		44.34%	44.75%	43.16%	46.22%	46.85%	44.46%	42.43%	39.96%	36.86%	34.52%
PROSPECTIVE		45.01%	45.41%	43.82%	46.87%	47.49%	45.10%	43.06%	40.57%	37.46%	35.12%
ADJUSTED POTENTIAL		45.14%	45.76%	44.16%	47.21%	47.83%	45.43%	43.38%	41.28%	38.15%	35.80%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-SE-Figure 1: Summer (Left) and Winter[259] (Right) Planning Reserve Margins



Long-term demand is expected to grow even though the levels of economic activity and production are lower than pervious assessments. Additional contributing factors to adequate margins are the addition of resources and the expiration or acquisition of Firm purchase contracts. Utilities do not adhere to any targets or Reserve Margin criteria. However, the state of Georgia requires maintaining at least 13.5 percent near-term (fewer than three years) and 15 percent long-term (three years or more) Reserve Margin levels for investor-owned utilities. All entities indicate that projected Reserve Margins remain above 15 percent, the NERC Reference Margin Level.

Reserves for the period are anticipated to be adequate due to reductions in load forecast resulting from the recent recession and economic downturn, assuming typical weather and operating conditions.

Demand

Entities within the SERC-SE Assessment Area are projecting a 1.42 percent growth rate, a slight decrease compared to the 2011 LTRA (SERC-SE-Table 2).

SERC-SE-Table 2: Demand Outlook

SERC-SE-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	47,900	54,249	6,349	13.3%	1.39%
Load-Modifying Demand Response	1,899	2,263	364	19.2%	1.97%
TOTAL INTERNAL DEMAND	**49,799**	**56,512**	**6,713**	**13.5%**	**1.42%**

SERC-SE-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	44,652	50,627	5,975	13.4%	1.41%
Load-Modifying Demand Response	1,882	2,267	385	20.5%	2.09%
TOTAL INTERNAL DEMAND	**46,534**	**52,894**	**6,360**	**13.7%**	**1.43%**

[259] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

The change is mostly driven by the slower-than-expected recovery from the recession as compared to last year. The assumptions in SERC-SE's economic forecast indicate that it is in the recovery phase, even though recovery has been slow. The economic fundamentals of the Region are still strong. Forecasters are anticipating that when the job market recovers, the housing market will follow and this will lead to a period of self-sustaining load growth. Normal weather assumptions are used to forecast the load shapes for various classes. Economic assumptions are captured from analytical vendors for the area. The recession affected short-term growth for energy and peak demand forecast. Adjustments were needed to reflect lower energy sales, milder temperatures, and the slow economic recovery, as well as to capture a more attainable consumer forecast.

Demand-Side Management

The Demand Response available on-peak is projected to be 1,899 MW for 2013 and 2,263 MW by 2022 (SERC-SE-Table 3). Entities currently reflect Energy Efficiencies in the load forecasts. These programs allow entities within the reporting area to have better ability to control various amounts of load and capacity when needed for reliability purposes. Extreme real-time pricing response is considered as a capacity resource. Distribution efficiency programs consist of adding capacitors on distribution circuits to reduce line losses and to smooth out voltage drop across the circuit. In addition, Conservation Voltage Reduction activation reduces the voltage on the distribution circuit at the voltage regulator or load tap transformer, reducing the customer's demand. Additional objectives of some of the programs are as follows:

- Help reduce the need to build or purchase capacity.
- Respond to volatile wholesale energy markets.
- Improve the efficiency (load factor) as well as the utilization of generation, transmission, and distribution systems.
- Provide low-cost energy to member cooperatives.
- Increase off-peak kWh sales.

SERC-SE-Table 3: Projected Demand-Side Management

	Short-Term					
SERC-SE	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	626	825	848	912	286	1.61%
Contractually Interruptible (Curtailable)	1,188	1,188	1,267	1,252	64	2.22%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	85	87	89	99	14	0.18%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,899	2,100	2,204	2,263	364	4.00%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**1,899**	**2,100**	**2,204**	**2,263**	**364**	**4.00%**

There is no significant change in the amount of Demand Response since last year's reporting period. Demand Response is projected to account for 3.8 to 4 percent of Total Internal Demand from 2013 to 2022. Additionally, Demand Response is projected to increase by 12.5 percent in 2013 from the 2011 long-term assessment period. Currently, entities include Energy Efficiencies in load forecasts and it is not reported separately in this assessment. Additional Energy Efficiency programs are being considered for residential, commercial and industrial customers in the area. Over 500 programs are being reviewed for consideration for future implementation, but not all programs will be implemented. After a program is approved by the Public Service Commission for implementation and after the implementation begins, a general evaluation plan is developed into a more detailed evaluation plan through a bid process with consultants who have the expertise to develop and perform thorough program evaluations.

Demand Response programs within the area consist of programs ranging from customer stand-by generation, real-time pricing/critical-peak pricing (reduce energy use based on price signaling), and interruptible demand programs (requests customers to reduce energy use), to direct load control programs (energy provider reduces customer energy use). Various utilities have residential Energy Efficiency programs that may include educational presentations, home energy audits, home inspector programs, compact fluorescent light bulbs, electric water heater incentives, heat pump incentives, Energy Efficient new home programs, Energy Star-rated appliance promotions, appliance recycling programs, loans or financing

options/incentives, weatherization, programmable thermostats, and ceiling insulation. Commercial programs may include energy audits, lighting programs, and plan review services.

Other programs, such as business assistance/audits, weatherization assistance for low-income customers, residential energy audits, and comfort advantage Energy Efficient home programs promote reduced energy use and supply information and develop Energy Efficiency presentations for various customers and organizations. Some entities are beginning to work with states' energy divisions on Energy Efficiency planning efforts. Training seminars addressing Energy Efficiency, HVAC sizing, and energy-related end-use technologies are also offered to educate customers.

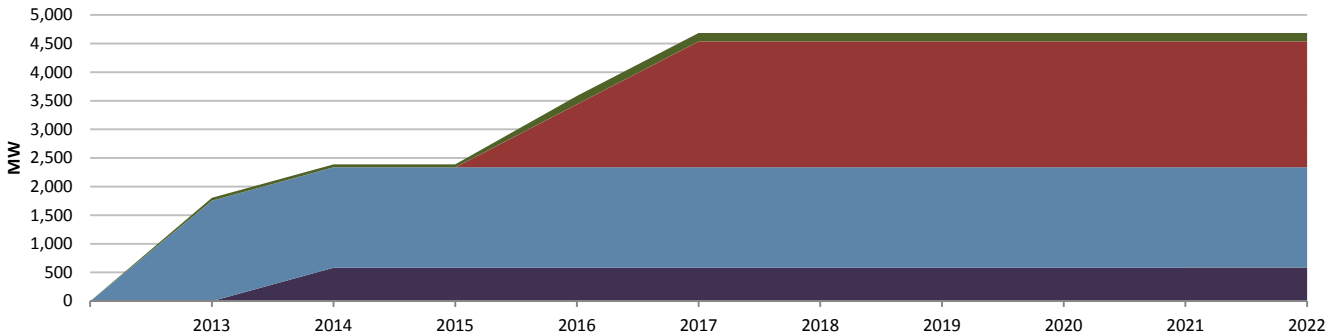
Generation

Companies within the SERC-SE Area expect to have 62,312 MW of Existing-Certain, 300 MW of Existing-Other, 0 MW of Existing-Inoperable, 1,807 MW of Future-Planned, and 142 MW of Conceptual resources on-peak respectively for 2013. Additionally, 4,688 MW of Future-Planned resources and 430 MW of Conceptual resources are expected to be added in 2022. The major additions to the area include Plant Ratcliffe IGCC and Plant Vogtle Units 3 and 4. The Vogtle units represent the first new nuclear units constructed in over 30 years in the United States and will begin operation in 2016 and 2017, respectively. This capacity is projected to help meet demand during this time period. Gas is the primary source of fuel within this area. An additional 841 MW of Existing-Certain resources have been added since the prior season. Gas-fired Future-Planned resources are projected to increase by 130 MW during the summer of 2012. Entities have reported 107 MW of unit retirements during 2012 and 1,032 MW of unit retirement throughout the period. There may be a reliability concern involving the uncertainty in generating resource availability in 2015 and beyond introduced by the recent implementation of EPA MATS rules and other pending environmental rules. Entities in the area are working to assess resource availability and potential unit retirements. Additional transmission enhancements have been identified and will be re-assessed during the spring planning cycle for possible inclusion in the 10-year expansion plans (SERC-SE-Table 4 and SERC-SE Figure 2).

SERC-SE-Table 4: Capacity Outlook[260]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-SE-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	24,604	38.9%	25,189	37.1%	585	25,189	36.8%	585
Petroleum	1,017	1.6%	1,017	1.5%	0	1,017	1.5%	0
Gas	26,763	42.3%	28,520	42.0%	1,757	28,738	42.0%	1,975
Nuclear	5,818	9.2%	8,018	11.8%	2,200	8,018	11.7%	2,200
Other/Unknown	13	0.0%	13	0.0%	0	19	0.0%	6
Renewables	5,063	8.0%	5,209	7.7%	146	5,416	7.9%	352
TOTAL	**63,278**	**100.0%**	**67,966**	**100.0%**	**4,688**	**68,396**	**100.0%**	**5,118**

SERC-SE-Figure 2: Summer Net Capacity Change



New generator uprates are not reported to be in service during the period. In addition, no generation is expected to be brought back into service. Entities are currently working through solutions in order to address potential unit unavailability

[260] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

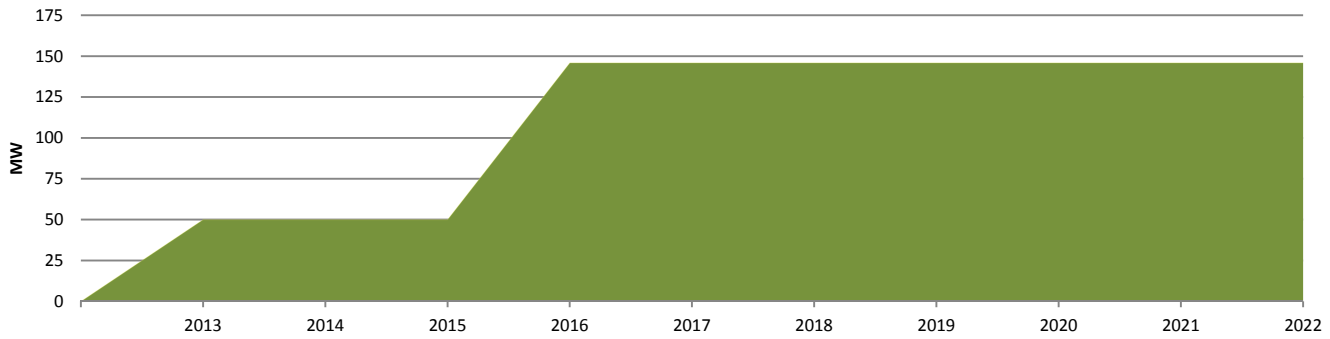
that may occur in the future. Behind-the-meter generation and Other/Unknown resources are also not anticipated during the period.

Only Firm Capacity Resources are counted toward the Planning Reserve Margins at peak in calculations. However, Future-Planned biomass generation is included in the Integrated Resource Plans at less than the nameplate capacity for converted boilers, and at nameplate capacity for units receiving new boilers. Landfill gas facilities are included at their nameplate ratings. Contracts with external parties for these resources usually require proof of capacity and allow for capacity payment penalties for excessive unavailability and derating events (SERC-Table 5 and SERC-Figure 3).

SERC-SE-Table 5: Renewable Capacity Outlook[261]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-SE-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	3,360	66.4%	3,360	64.5%	0	3,360	62.0%	0
Pumped Storage	1,632	32.2%	1,632	31.3%	0	1,632	30.1%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	0	0.0%	0	0.0%	0	0	0.0%	0
Biomass	67	1.3%	213	4.1%	146	419	7.7%	352
Solar	4	0.1%	4	0.1%	0	4	0.1%	0
TOTAL	**5,063**	**100.0%**	**5,209**	**100.0%**	**146**	**5,416**	**100.0%**	**352**

SERC-SE-Figure 3: Summer Net Renewable Capacity Change



Currently, entities are enhancing their methods for incorporating variable resources into their planning processes. Variable resources are currently evaluated by analyzing their historical or projected output profiles (SERC-Table 6). The result will be a determination of the comparative capacity value to that of a typical combustion turbine on the system.

SERC-SE-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
SERC-SE-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	0	4	3,360	67	0	4	3,360	213
On-Peak Derate	0	0	0	0	0	0	0	0
EXPECTED ON-PEAK OUTPUT	0	4	3,360	67	0	4	3,360	213
SHARE OF ON-PEAK CAPACITY	**0.00%**	**0.01%**	**5.31%**	**0.11%**	**0.00%**	**0.01%**	**5.02%**	**0.32%**

Capacity Transactions

Utilities within SERC-SE expect the following imports and exports listed below for the period. These imports and exports have been accounted for in the Reserve Margin calculations for the reporting area. The majority of the contracts in the area are yearly Firm agreements typically lasting five or more years. All imports and exports were reported to be backed by Firm contracts for both generation and transmission, but none are associated with LDCs or are considered "make whole." Once the contract ends, the unit's capacity is changed from Existing-Certain to Existing-Other. Firm imports amount to 850 MW in 2013 and ultimately drop to 446 MW in 2022. Exports fall from 2,862 MW in 2013 to 1,705 MW in 2022 (SERC-SE-Table 7).

[261] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Projected Capacity Transactions

SERC-SE-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	850	900	900	825	825	825	825	825	546	446
TOTAL IMPORTS	850	900	900	825	825	825	825	825	546	446
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	2,862	2,703	2,690	1,399	1,547	1,555	1,671	1,690	1,697	1,705
TOTAL EXPORTS	2,862	2,703	2,690	1,399	1,547	1,555	1,671	1,690	1,697	1,705
TOTAL NET CAPACITY TRANSACTIONS	**-2,012**	**-1,803**	**-1,790**	**-574**	**-722**	**-730**	**-846**	**-865**	**-1,151**	**-1,259**

Reporting entities maintain emergency reserve sharing agreements with organizations internal to the area and other contract agreements with neighboring utilities provide capacity for outages of specific generation. Total emergency MW from these imports were not reported, but are available as needed. Overall, entities are not dependent on outside imports or transfers to meet the demands of its load.

Transmission

Currently, there are no concerns with meeting in-service dates for transmission improvements or specific projects needed to maintain reliability. Significant projects in SERC-SE that have been finalized are:

- Dresden–Heard County 500 kV Transmission Line
- Thomson Primary–Vogtle 500 kV Transmission Line
- Greene County–Bassett Creek 230 kV Transmission Line
- Pinckard–Holmes Creek–Highland City 230 kV Transmission Line

A summary of existing and projected transmission additions is included in the table below (SERC-SE-Table 8).

SERC-SE-Table 8: Existing and Projected Transmission

SERC-SE	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	27,672	0	27,672
Currently Under Construction	108	0	108
Planned - Completed within First Five Years	305	0	305
Planned - Completed within Second Five Years	374	0	374
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	28,459	0	28,459
Conceptual - Completed within First Five Years	66	0	66
Conceptual - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**853**	**0**	**853**

Entities consistently evaluate the transmission system through operating studies and a model construction process. These evaluations address any potential delays in construction and are used to determine switching procedures, operating procedures, or near-term improvements that may be necessary should an in-service date of a bulk facility be adjusted. The Reliability Coordinator and Transmission Operators also work with impacted entities to coordinate construction and outage schedules to maintain reliable operations.

To address reliability concerns for the 10-year planning horizon, entities are conducting comprehensive reliability assessments consistent with NERC planning criteria and developing transmission expansion plans to address identified constraints in advance of reliability needs. Transmission projects identified in the expansion plans will be constructed to coincide with the integration of new and retirement of existing generation resources, load growth, and other Firm service requirements. Potential additional transmission enhancements have been identified due to EPA regulations and will be reassessed during the spring planning cycle for possible inclusion in the 10-year expansion plans. Significant outage coordination is underway to ensure that all projects can be completed by the required in-service dates without affecting system reliability. These spring planning assessments may also lead to requests associated with MATS rule implementation requirements to operating units beyond 2015 as needed to maintain reliability. A related reliability concern involves the extensive generation and transmission construction work that must be completed prior to the 2015 implementation of MATS. At this time, entities in the area do not have plans to add new technologies or significant substation equipment. Companies will continue to assess potential applications for these technologies in assessing reliability needs during annual expansion planning processes and are prepared to deploy these technologies in suitable applications.

Vulnerability Assessment

Resource adequacy is determined by extensive analysis of costs associated with expected unserved energy, market purchases, and new capacity. These costs are balanced to identify a minimum cost point that is the optimum Reserve Margin level. No system reliability concerns for the period have been identified in the latest resource adequacy studies. Fuel availability and hydro and reservoir conditions are expected to be normal throughout the reporting period. Assessments are currently in progress to assess the effects of the EPA regulations on generation availability in 2015 and beyond. Additionally, the variable resources that have been procured as energy resources are not presently relied upon to meet resource adequacy requirements. However, some entities are in the process of enhancing their methods to incorporate variable resources. Currently, variable resources are evaluated by analyzing their historical or projected output profiles. The result will be a determination of the comparative capacity value to that of a typical combustion turbine on the system. Demand Response is not a factor, and Renewable Portfolio Standard requirements do not currently exist in the service territory.

A 2,250 MW UVLS scheme currently exists in northern Georgia. The scheme was installed to help meet three-phase faults with breaker failure contingencies. There are no future plans to install more schemes.

Utilities within the reporting area use various tactics to prepare for catastrophic events. Company-specific processes and guidelines for coal, natural gas, and transmission usage are areas that companies consider to be most critical. To address the coal concerns, several resource adequacy studies were conducted to evaluate the ability to meet peak demand while considering the historic and probabilistic limitations of import interfaces. Transmission studies are regularly performed. Loss-of-pipeline, extreme events (TPL-003 and TPL-004), and infrastructure security are taken into consideration. The purpose is to assess vulnerability for catastrophic events and develop appropriate mitigation plans. The general conclusion is that the system is capable of weathering many potential catastrophic events with minimal impact on neighboring systems.

There are three existing Special Protection Systems in the SERC-SE Area. They are located at Plant Daniel (230kV), Plant Crist (115kV) and Plant Wilson (230kV). Plant Wilson's SPS will be retired by 2015 when the breaker replacement project is complete. SERC reviews each SPS every five years as well as any SPS retirement.

Currently in SERC-SE, entities are proceeding with various smart grid projects to help enhance the reliability of the transmission system. These projects include replacing older electromechanical relays with microprocessor relays, installing transformer equipment monitors, automating transmission line switches, installing digital fault recorders (DFRs) and installing human machine interfaces (HMI's) in substations.

The utilities in SERC-SE have procedures in place to identify and review misoperations caused by protection systems. When a misoperation occurs on the transmission system, corrective action is implemented to prevent recurrence. If needed, other locations are also reviewed for similar problems. Misoperations caused by protection systems are reviewed on an annual basis for possible trends.

As stated in the above sections, a reliability concern involves uncertainty in generating resource availability in 2015 and beyond, introduced by the recent implementation of EPA MATS rules and other pending environmental rules. All entities in the area are fully engaged in assessing resource availability and potential unit retirements. Resource adequacy, expansion plans and models will be updated if the decisions for the retirement of various units become available. Potential transmission enhancements have been identified from recent assessments and will be re-assessed in future expansion plans. These assessments may also lead to requests associated with MATS implementation requirements to operating units beyond 2015 as needed to maintain reliability. Plans also include the Reliability Coordinator and Transmission Operators coordination efforts to decide construction and outage schedules to maintain reliable operations.

Standing and Emerging Reliability Issues

A significant reliability concern involves the uncertainty of generating resource availability in 2015 and beyond, introduced by the recent implementation of EPA MATS rules and other pending environmental rules being promulgated. The SBA Planning Authority is working with Load Serving Entities and Generator Operators to assess resource availability and potential unit retirements. Potential additional transmission enhancements have been identified and will be re-assessed during future expansion plans. These assessments may also lead to requests associated with MATS implementation requirements to operating units beyond 2015 as needed to maintain reliability.

A related reliability concern involves the extensive generation and transmission construction work that must be completed prior to the 2015 implementation of MATS. The Reliability Coordinator and Transmission Operators are working with impacted entities to coordinate construction and outage schedules to maintain reliable operations.

SERC-W

Planning Reserve Margins

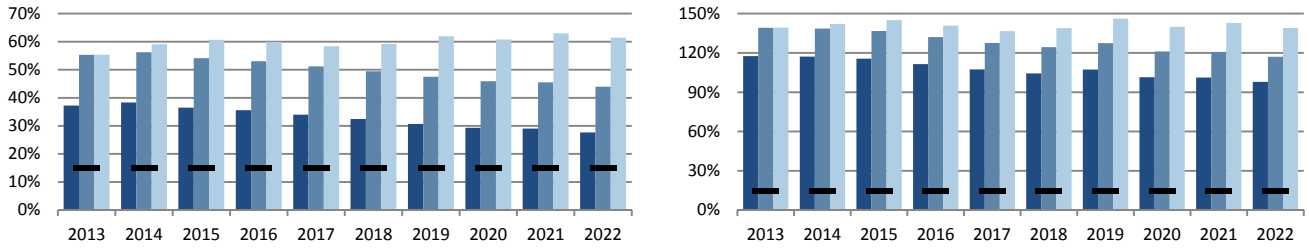
The reporting area is projecting adequate Anticipated Capacity Resource Reserve Margins from 2013 to 2022, ranging between 26.1 and 35.5 percent. None of the Planning Reserve Margins are projected to fall below the NERC Reference Margin Level of 15 percent (SERC-W-Table 1 and SERC-W-Figure 1).

SERC-W-Table 1: Planning Reserve Margins

SERC-W-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		37.26%	38.35%	36.48%	35.60%	33.98%	32.44%	30.70%	29.32%	29.04%	27.68%
PROSPECTIVE		55.32%	56.24%	54.12%	53.03%	51.19%	49.46%	47.49%	45.93%	45.49%	43.96%
ADJUSTED POTENTIAL		55.36%	59.05%	60.69%	59.91%	58.38%	59.22%	61.95%	60.79%	62.93%	61.44%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-W-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		117.6%	117.2%	115.6%	111.5%	107.4%	104.4%	107.2%	101.4%	101.2%	97.8%
PROSPECTIVE		139.2%	138.5%	136.7%	132.1%	127.6%	124.3%	127.5%	121.1%	120.7%	117.0%
ADJUSTED POTENTIAL		139.3%	142.1%	145.1%	140.8%	136.6%	138.9%	146.1%	139.9%	142.8%	139.0%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-W-Figure 1: Summer (Left) and Winter[262] (Right) Planning Reserve Margins



Contributing factors to adequate margins exist and owned resources, limited and long-term purchase contracts, as well as potential deactivations and anticipated unit outages to plan and procure resources needed to meet the target Reserve Margin when developing plans for the season. Individual entity criteria also help establish resource adequacy by allocations assigned as a member of the SPP Reserve Sharing Group, Balancing Authority's most severe single contingency, load forecasts, reserve requirements using historical allocations, and Loss of Load Expectation studies (0.1 day per year). There are no other anticipated reliability concerns for the period.

Demand

Entities in the SERC-W Assessment Area project decreases in growth rates when comparing the 2013 long-term forecast (1.15 percent) to the 2011 forecast (1.30 percent) (SERC-W-Table 2).

SERC-W-Table 2: Demand Outlook

SERC-W-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	25,015	27,764	2,749	11.0%	1.17%
Load-Modifying Demand Response	906	966	60	6.6%	0.72%
TOTAL INTERNAL DEMAND	**25,921**	**28,730**	**2,809**	**10.8%**	**1.15%**

SERC-W-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	19,731	22,262	2,531	12.8%	1.35%
Load-Modifying Demand Response	766	820	54	7.0%	0.76%
TOTAL INTERNAL DEMAND	**20,497**	**23,082**	**2,585**	**12.6%**	**1.33%**

The modest decrease in growth is due to lower economic projections received from vendors as they adjusted forecasts to reflect a longer recovery from the recession. Decreases also reflect a reduction in the long-term outlook for retail electric sales due to this forecast. Typical weather conditions are used to forecast the load shapes for the residential, commercial,

[262] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

and governmental classes. The forecast assumes a gradual economic recovery. Entities in the area regularly develop load scenarios for outage planning purposes. These load scenarios include load forecasts based on high and low scenarios for energy sales and scenarios for alternative capacity factors. No significant changes are reflected in this year's assumptions.

Demand-Side Management

Demand Response is expected to be 906 MW for 2013 and 966 MW by 2022. Currently, there are no Energy Efficiency contributions projected during this reporting period. Demand Response accounts for approximately 3.5 and 3.4 percent of Total Internal Demand in 2013 to 2022, respectively (SERC-W-Table 3). Demand Response is projected to increase 3.4 percent from 2011 to 2013. There is no significant change in the amount of load reduction programs since last year. DSM programs among the utilities in the reporting area include interruptible load programs for larger customers, Direct Control Load Management programs for agricultural customers, and a range of conservation/load management programs for all customer segments. There are no significant changes in the amount and availability of load management and interruptible demand since last year.

SERC-W-Table 3: Projected Demand-Side Management

	Short-Term					
SERC-W-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	906	909	940	966	60	3.36%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	906	909	940	966	60	3.36%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**906**	**909**	**940**	**966**	**60**	**3.36%**

Energy Efficiency programs are implemented to distribution cooperatives and the residential sector. A variety of programs ranging from home energy audits, CFL lighting, and Energy Star-rated washing machines and dishwashers, to Energy Star-rated heat pumps and air conditioners, weatherization and high efficiency water heaters have been added to company portfolios over the years. Utilities plan to offer these types of programs as long as they are determined to be cost-effective. Annual measurement and verification (M&V) programs measure energy savings and costs for each of these Energy Efficiency programs. Information from these M&V programs will be used to fine-tune Energy Efficiency programs and determine their cost-effectiveness. The current forecast includes Energy Efficiency programs that have received regulatory approval. As programs advance, they will be incorporated into retail sales and load forecasts. M&V for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and Firm load requirements. Compliance is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule. Companies adhere to measurement and verification requirements set forth by state regulators.

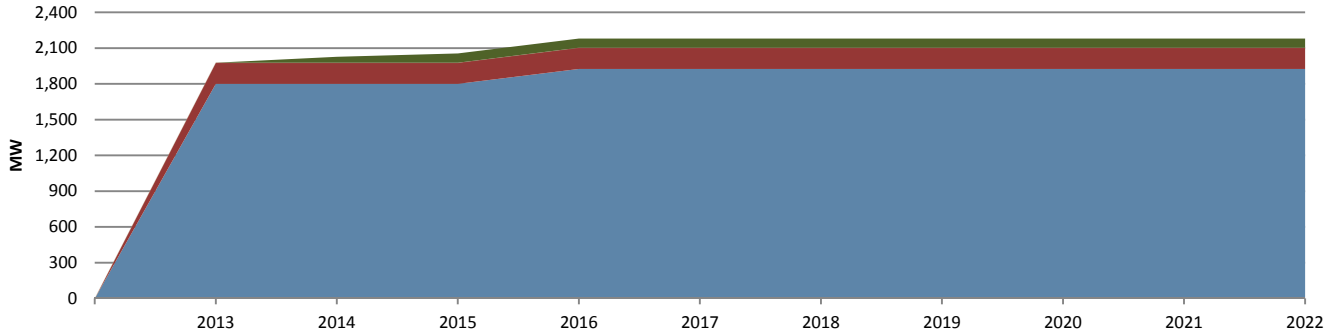
Generation

Companies within SERC-W expect to have 34,175 MW of Existing-Certain, 4,519 MW of Existing-Other, 0 MW of Existing-Inoperable, 1,978 MW of Future-Planned, and 10 MW of Conceptual resources on-peak for 2013 (SERC-W-Table 4 and SERC-W-Figure 2). Additionally, 2,181 MW of Future-Planned resources and 4,853 MW of Conceptual resources are expected to be added in 2022. This capacity is projected to help meet demand during this time period. Oil, gas, and dual fuel units are the primary sources of fuel within this area. No Existing-Certain resources have been added since the previous long-term reporting period. Entities have reported no unit retirements since the previous long-term reporting period. However, 93 MW of unit retirements will occur in 2013. No significant negative impact to reliability due to capacity limitations is anticipated for the period.

SERC-W-Table 4: Capacity Outlook[263]

SERC-W-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Coal	6,300	17.3%	6,300	16.3%	0	6,300	14.5%	0
Petroleum	41	0.1%	41	0.1%	0	41	0.1%	0
Gas	24,494	67.2%	26,420	68.4%	1,926	30,046	69.1%	5,552
Nuclear	5,324	14.6%	5,502	14.2%	178	5,627	12.9%	303
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	311	0.9%	388	1.0%	77	1,490	3.4%	1,179
TOTAL	**36,470**	**100.0%**	**38,651**	**100.0%**	**2,181**	**43,504**	**100.0%**	**7,034**

SERC-W-Figure 3: Summer Net Capacity Change

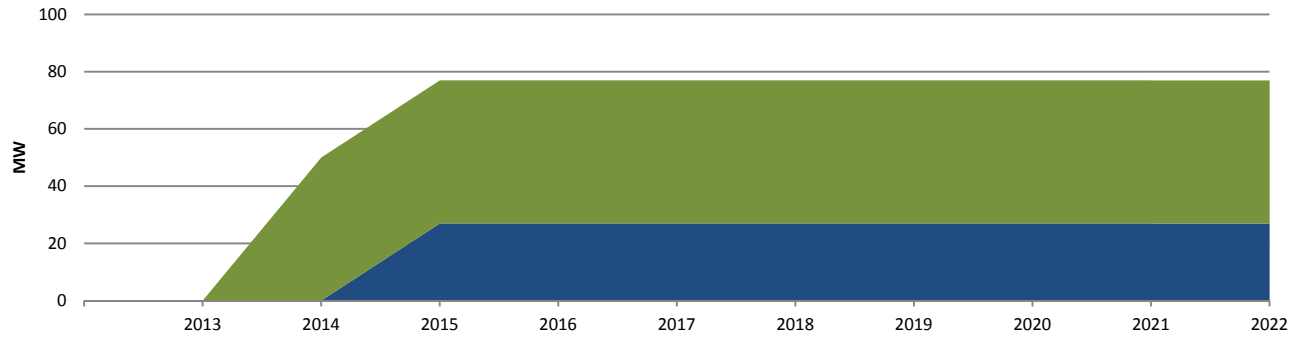


There are also no new generator uprates or generation taken out of service during the period. However, a 57 MW natural gas unit will be brought back into service for the period. Behind-the-meter generation and Other/Unknown resources are also not expected to be in service for the period.

SERC-W-Table 5: Renewable Capacity Outlook[264]

SERC-W-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Hydro	311	100.0%	338	87.1%	27	607	40.8%	296
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	0	0.0%	0	0.0%	0	23	1.5%	23
Biomass	0	0.0%	50	12.9%	50	860	57.7%	860
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**311**	**100.0%**	**388**	**100.0%**	**77**	**1,490**	**100.0%**	**1,179**

SERC-W-Figure 4: Summer Net Renewable Capacity Change



Due to an insignificant amount of variable generation connected to the distribution system, there are no concerns about integrating these resources onto the system. Currently, entities are studying potential approaches for incorporating variable

[263] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[264] *Ibid*.

resources into their planning processes. Wind agreements are used as a tool to allow operators to enhance reliability and can be used in situations such as curtailing for TLR and managing minimum generation problems. An energy forecasting package is used to predict wind farm output given meteorological data collected at the wind farms. No issues are anticipated for the period.

SERC-W-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
SERC-W-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	0	0	311	0	0	0	338	50
On-Peak Derate	0	0	0	0	0	0	0	0
EXPECTED ON-PEAK OUTPUT	0	0	311	0	0	0	338	50

Capacity Transactions

Utilities within SERC-W expect the following imports and exports listed below for the period. These imports and exports have been accounted for in the Reserve Margin calculations for the reporting area. Most of the contracts in the area are agreements for a 10-year period for the winter and summer peaking seasons. Once the contract ends, the unit's capacity is changed from Existing-Certain to Existing-Other.

SERC-W-Table 7: Projected Capacity Transactions

SERC-W-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	50	50	50	50	50	50	50	50	50	50
TOTAL IMPORTS	50	50	50	50	50	50	50	50	50	50
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	2,304	1,746	1,746	1,671	1,671	1,671	1,671	1,671	1,392	1,392
TOTAL EXPORTS	2,304	1,746	1,746	1,671	1,671	1,671	1,671	1,671	1,392	1,392
TOTAL NET CAPACITY TRANSACTIONS	**-2,254**	**-1,696**	**-1,696**	**-1,621**	**-1,621**	**-1,621**	**-1,621**	**-1,621**	**-1,342**	**-1,342**

Reporting entities in the area are dependent on certain imports, transfers, or contracts to meet the load demands. Most entities are members of the Southwest Power Pool (SPP) Reserve Sharing Group. Group participants within SPP generally transfer reserves into the area to either replace (largest contingency) or supply generation to the area. These reserves are not relied on in the resource adequacy assessment, or for capacity or Reserve Margins. System operators generally coordinate the scheduling and transmitting of the reserves. Total emergency MW from these imports was not reported.

Transmission

Entities within the reporting area are not expecting any delays in meeting in-service dates for projects scheduled for the summer assessment period. Some of the significant projects that are planned or have been recently completed in SERC-W are:

- Acadiana Load Pocket Project Phases 1 and 2: Completed in June, 2012. Project creates a new 230 kV overlay in the Acadiana Area of south Louisiana.
- Ouachita Transmission Projects: Completed in June, 2012. Projects included increasing 500-115 kV transformer capacity in northern Louisiana, upgrades of various 115 kV lines around the Sterlington Area, and the addition of a 2nd 500-115 kV transformer at the Baxter Wilson substation in Mississippi.
- Grenada/Winona/Greenwood Area Improvement Project: Completed in June, 2012. Project included the construction of a new Tillatoba–South Grenada 230 kV line and a 230-115 kV transformer at South Grenada.
- Holland Bottoms Project: Completed in May 2012. Project included the addition of 500-161 and 500-115 kV transformers in the northeast Little Rock Area of Arkansas and the construction of a new 161 kV transmission line from Holland Bottoms to the Hamlet substation north of the Little Rock Area.
- Nelson to Moss Bluff 230 kV line: Completed in May, 2012. Project included the construction of a new 230 kV line in the Lake Charles Area of southern Louisiana.
- Northeast Louisiana Improvement Project Phases 1 and 2: Projected in service by summer 2013 and summer 2014, respectively. Project includes construction of new 230 kV line (to operate at 115 kV initially) from the Monroe Area of northern Louisiana to the Delhi Area in order to increase transmission capacity in the Area.

- Getwell to Church Road 230 kV line: Projected in-service date by summer 2013. Project includes the construction of a new 230 kV line between Church Road and Getwell substations in north Mississippi and create a 230 kV loop in the Area.

SERC-W-Table 8: Existing and Projected Transmission

SERC-W	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	14,295	0	14,295
Currently Under Construction	72	0	72
Planned - Completed within First Five Years	414	0	414
Planned - Completed within Second Five Years	79	0	79
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	14,860	0	14,860
Conceptual - Completed within First Five Years	26	0	26
Conceptual - Completed within Second Five Years	92	0	92
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**683**	**0**	**683**

Additionally, there are no significant transmission facility outages or significant projects that are expected to impact BES reliability. Utilities in SERC-W continue to identify and develop plans to construct or upgrade transmission facilities to meet reliability needs and incorporate new generation resources in the area for both the near-term and long-term planning horizons. Transmission projects are planned to be constructed to support the Future-Planned generation in the SERC-W Area. Prior to approval of any proposed maintenance outages, studies are completed to identify any impact on reliability. In addition, 2012 near-term summer preliminary results indicate that with operating guides in place, imports into the Area exceed 2,000 MW for all paths studied. To enhance the system, entities continue to research new technologies such as dynamic voltage devices (SVC/Statcom) to provide voltage support to the Area. However, no additional SVC/Statcom or other specialized devices are expected to be added during the long-term period. Some utilities in SERC-W are involved in adding PMUs as part of an ongoing DOE project. The project will allow a greater visualization of the transmission system for transmission system operators. Twelve PMUs were installed in 2011, with an additional 23 PMUs planned to be installed throughout the transmission system in 2012.

Vulnerability Assessment

Existing and owned resources, limited and long-term purchase contracts, potential deactivations, and anticipated unit outages are considered when developing the one-year and 10-year resource plan. The latest resource adequacy studies do not show concerns for reliability of the system. Resource availability, fuel availability, and hydro conditions are expected to be normal during the summer, except for possible hydro limitations in Texas. Energy production in Texas may be limited due to existing drought conditions, unless above-normal rainfall is experienced during winter and spring months. Studies in these areas account for these conditions. Loss-of-load studies are performed annually for the current year based on updated load forecasts and unit availability data. The long-term test of resource adequacy is met by achieving a 16.85 percent Planning Reserve Margin.

Demand Response, distributed generation, variable renewable resources and Renewable Portfolio Standards (RPS) are not currently explicitly considered in the resource adequacy assessment. However, an RFP was recently conducted for Louisiana to identify and select renewable energy resources that meet the requirements of the Louisiana Public Service Commission's Pilot Program and approved Implementation Plan. These plans are consistent with the objectives of Entergy's Systems Strategic Resource Plan. Selections have been made, and ESI will be entering into discussions for the execution of definitive agreements associated with the proposals on the primary selection list.

Studies are being conducted for 2012 and 2018 summer time periods to identify additional static and dynamic reactive support requirements in the Nine Mile Area. Based on the study results, recommendations may be to install SVCs or capacitor banks, change transformer tap settings, or add new transmission facilities to ensure adequate reactive requirements are met. UVLS programs are also used to maintain voltage stability and protect against BES cascading events. An existing 250 MW UVLS scheme is used in the western area of Texas. No additional UVLS schemes are planned for the reporting area. In addition, no Special Protection Schemes are expected to be installed for the SERC-W Area in lieu of planned bulk power transmission facilities.

Resource and transmission planning activities consider contingency events to help entities prepare for catastrophic events. Close relationships with neighboring utilities and regular emergency operating drills are important practices of utilities. Entities within this reporting area are routinely exposed to hurricanes, and detailed emergency response plans have been developed for dealing with the consequences of hurricane damage to area electrical systems. One way that catastrophic events are mitigated is that gas-fired power plants do not rely on a single pipeline for transportation of natural gas. Likewise, most entities do not heavily rely on imports outside the reporting areas due to the loss of a major import that could negatively affect reliability.

Utilities within SERC-W have procedures in place to identify and review misoperations associated with transmission protection systems. In the event of a misoperation on the transmission system, investigations, including root cause analysis, are performed to determine corrective actions and implementation plans. Corrective action plans may cause an entity to evaluate other facilities for similar causes of misoperation.

There are no environmental or regulatory restrictions projected within the reporting area that will affect reliability for the period. The CSAPR rules, which have been stayed by federal courts, were not expected to result in any new reliability-must-run (RMR) units in SERC-W. In the event that there were insufficient allowances to operate existing RMR units at historical levels, it was possible to run these units at reduced production levels while ensuring grid reliability. Additional flexibility was expected with the October 2011 proposed revision. The increased flexibility allowed by this revision created additional possibilities for compliance, including interstate allowance purchases. Prior to the proposed October limits, some utilities in SERC-W had identified potential transmission upgrades in which acceleration of existing transmission projects was being considered. These are existing BES projects in various stages of planning, design, and construction. However, with the proposed October 2011 limits, no BES projects were identified in which acceleration prior to 2012 was required. Off-peak maintenance outages are not expected to affect reliability in the SERC-W Area.

Beyond the impact of CSAPR itself, utilities in the SERC-W Area do not anticipate a significant, immediate impact to system reliability due to the combined effects of CSAPR and other emerging environmental regulations. While the short implementation period allowed for CSAPR created concerns, other emerging rules are expected to have varying implementation dates that will provide adequate time for planning and execution of control projects. In addition, coal plants, which will be most affected by emerging regulations, are positioned relatively well in regard to their capacity and age, such that most projected environmental projects are currently estimated to be economically viable and are not expected to drive early retirements.

Utilities within SERC-W report that the deadlines created by the final EGU MACT rule could be problematic for the installation deadlines of major pollution control equipment for individual plants. This problem could also be compounded by the uncertainty over regional haze state implementation plan requirements. When plans are approved by the EPA, another layer of technology installments would be required. Utilities in the SERC-W Area believe that for coal plants, these are issues of timing, permitting, state public service commission approval, and rational project management, not retirement. The most immediate threat to reliability is likely to be in the 2020 time frame when units will be required to implement 316(b) controls and address any reductions driven by lower National Ambient Air Quality Standards (NAAQS). However, utilities in the SERC-W Area do not anticipate the suite of EPA regulations to result in significant facility retirements or generation reductions.

Standing and Emerging Reliability Issues

The CSAPR rules, which have been stayed, were not expected to result in any new reliability-must-run (RMR) units in SERC-W. In the event that there were insufficient allowances to operate existing RMR units at historical levels, it was still possible to run these units at reduced production levels while still ensuring grid reliability. Additional flexibility was expected with the October 2011 proposed revision. The increased flexibility allowed by this revision created addition possibilities for compliance, including interstate allowance purchases. Prior to the proposed October limits, some utilities in SERC-W had identified potential transmission upgrades in which acceleration of existing transmission projects was being considered.

These are current BES projects in various stages of planning, design, and construction. However, with the proposed October limits, no BES projects were identified in which acceleration prior to 2012 was required.

Beyond the impact of CSAPR itself, utilities in the SERC-W Area do not anticipate a significant, immediate impact to system reliability due to the combined effects of CSAPR and other emerging environmental regulations. While the short implementation period allowed for CSAPR created concerns, other emerging rules are expected to have varying implementation dates that will provide adequate time for planning and execution of control projects. In addition, coal plants, which will be most affected by emerging regulations, are positioned relatively well in regard to their capacity and age, such that most projected environmental projects are currently estimated to be economically viable and are not expected to drive early retirements.

Utilities note that depending on the deadlines created by the final EGU MACT rule, applicable deadlines for the installation of major pollution control equipment could be problematic for individual plants. This potential problem is compounded by the uncertainty over regional haze state implementation plan requirements, which when eventually approved by EPA, could require another layer of technology to be installed. Utilities believe that for coal plants, these are issues of timing, permitting, state public service commission approval, and rational project management, not retirement. The most immediate threat to reliability is likely to be in the 2020 time frame, when units will be required to implement 316(b) controls and will need to address any reductions driven by lower National Ambient Air Quality Standards (NAAQS). However, utilities do not anticipate the suite of EPA regulations to result in significant facility retirements or generation reductions.

SPP

Planning Reserve Margins

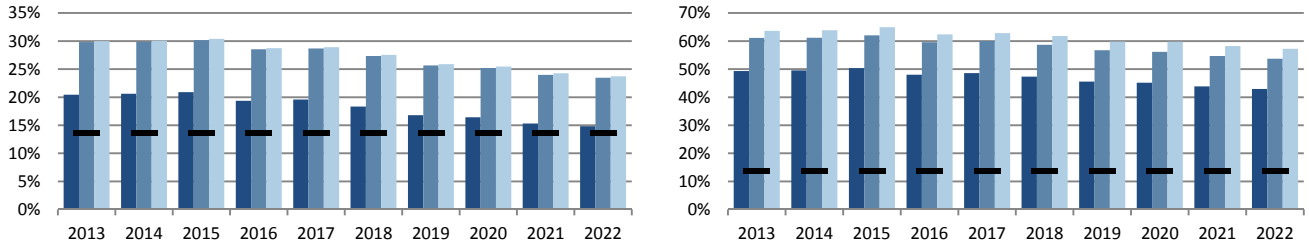
SPP criteria require members to maintain a minimum capacity margin of 12 percent. The SPP RTO is projected to have adequate Planning Reserve Margins throughout the assessment period well above SPP's required Reserve Margin of 13.6 percent, which is also used as the NERC Reference Margin Level. This level of adequacy is supported by the existing and planned generation within the SPP RTO footprint, along with the modest annual demand growth projections during the next 10 years.

SPP-Table 1: Planning Reserve Margins

SPP-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		20.44%	20.61%	20.90%	19.35%	19.60%	18.35%	16.80%	16.43%	15.33%	14.84%
PROSPECTIVE		29.81%	29.89%	30.17%	28.53%	28.69%	27.34%	25.67%	25.20%	23.98%	23.46%
ADJUSTED POTENTIAL		30.01%	30.09%	30.39%	28.75%	28.90%	27.55%	25.90%	25.47%	24.25%	23.73%
NERC REFERENCE	-	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**

SPP-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		49.32%	49.53%	50.33%	48.02%	48.60%	47.36%	45.59%	45.17%	43.84%	42.96%
PROSPECTIVE		61.10%	61.21%	62.04%	59.56%	60.04%	58.65%	56.72%	56.16%	54.69%	53.72%
ADJUSTED POTENTIAL		63.65%	63.88%	64.94%	62.38%	62.83%	61.82%	59.84%	59.74%	58.24%	57.23%
NERC REFERENCE	-	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**

SPP-Figure 1: Summer (Left) and Winter[265] (Right) Planning Reserve Margins



Although CSAPR was vacated in August 2012, other federal environmental regulations, which have compliance dates beginning in 2014 could cause the retirement of coal and gas units in the SPP RTO footprint. While the loss of base-load generation does not jeopardize SPP RTO's ability to meet the reserve margin requirements for the footprint, these retirements and/or outage scheduling may cause localized issues. Further discussion on the EPA regulations will take place later in this assessment.

Demand

The projected compound annual growth rate (CAGR) for the SPP RTO is approximately 1 percent from 2013 to 2022.

SPP-Table 2: Demand Outlook

SPP-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	54,247	58,985	4,738	8.7%	0.93%
Load-Modifying Demand Response	933	1,104	170	18.3%	1.88%
TOTAL INTERNAL DEMAND	**55,180**	**60,088**	**4,908**	**8.9%**	**0.95%**

SPP-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	40,983	44,862	3,879	9.5%	1.01%
Load-Modifying Demand Response	731	864	132	18.1%	1.86%
TOTAL INTERNAL DEMAND	**41,714**	**45,726**	**4,012**	**9.6%**	**1.03%**

The 2012 projected annual growth rate is slightly higher than the 2011 projections, primarily due to load growth in one large member's service territory. Throughout the rest of the SPP RTO footprint, economic growth is just now showing signs of slowing, even though the recession has been ongoing across the United States for several years.

[265] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Demand-Side Management

For 2013, SPP RTO projects 910 MW of Contractually Interruptible DR, 85 MW of Direct Control Load Management (DCLM) counted as a resources, 182 MW of load-modifying DCLM, and 28 MW of Load as a Capacity Resource. An additional 307 MW of new conservation (Energy Efficiency) is also projected. Total Demand Response is projected to increase from 1,513 MW in 2013 to 2,408 MW in 2022.

SPP-Table 3: Projected Demand-Side Management

	Short-Term					
SPP-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	85	94	104	175	89	0.29%
Contractually Interruptible (Curtailable)	187	271	286	320	133	0.53%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	272	365	390	495	223	0.82%
Direct Control Load Management (DCLM)	182	191	200	208	26	0.35%
Contractually Interruptible (Curtailable)	723	719	750	868	145	1.44%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	28	28	28	28	0	0.05%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	933	938	977	1,104	170	1.84%
TOTAL ENERGY EFFICIENCY	307	369	423	809	502	1.35%
TOTAL DEMAND-SIDE MANAGEMENT	**1,513**	**1,672**	**1,791**	**2,408**	**895**	**4.01%**

For 2022, SPP RTO projects 1,188 MW of Contractually Interruptible DR, 208 MW of Demand-Side DCLM, 175 MW of Supply Side DCLM, 28 MW of Load as a Capacity Resource, and 809 MW of new conservation (Energy Efficiency). SPP RTO projects a yearly increase in Demand Response programs until the year 2018 when the projections become more variable due to the discontinuation of certain programs.

Westar Energy launched its voluntary Demand Response program, Watt Saver, in September 2009. Watt Saver is open to single- and multi-family residential customers as well as small and medium commercial customers who receive a free Honeywell Utility Pro programmable thermostat and access to an online energy management system. From June through September, Watt Saver participants agree to allow Westar to cycle their central air conditioners or heat pumps (on and off in 15-minute intervals) in a coordinated effort to reduce energy demand during peak times. These cycling events normally last between four and six hours and run between noon and 8:00 p.m. Cycling events occur infrequently and only on standard work days. In 2011, Westar implemented the program six times. Currently, more than 32,000 Westar customers are enrolled in the program, which provides an estimated 27 MW of load reduction capability. Westar anticipates enrollment of 90,000 participants with a potential load reduction capability of 90 MW by the end of 2016.

SPP RTO member Oklahoma Gas and Electric (OG&E) installed approximately 40,000 smart meters on customer homes in Norman, Oklahoma in 2010, 2011, and 2012. The information delivery infrastructure was also installed to carry information to and from the customers and OG&E. This program will provide OG&E with 84 MW of Demand Response during peak hours.

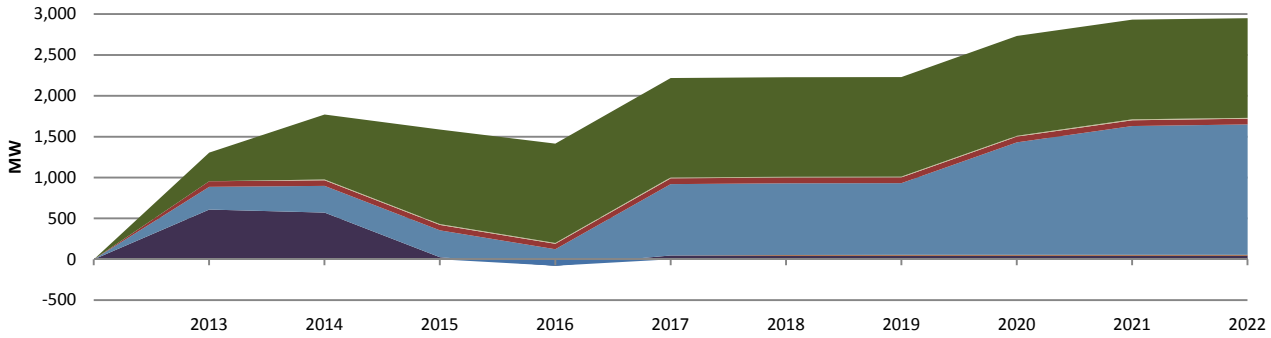
In January 2012, Kansas City Board of Public Utilities (KCBPU) started a voluntary program in which they will install a free Honeywell UtilityPro thermostat in customers' homes. Participating customers agree to allow KCBPU to raise the temperature in their home or business by up to two degrees. This will allow KCBPU to reduce summer electricity demand during periods of peak use and extreme heat. These peak events typically last no more than four hours and begin on a weekday afternoon and end in early evening. KCBPU expects to enroll 6,000 customers by the end of 2013, which will provide a demand reduction of approximately 10 MW.

Generation

For the current year 2012, SPP RTO forecasts 63,896 MW of Existing-Certain and 5,083 MW of Existing- Other. The primary fuel sources in the SPP RTO footprint are gas (46 percent) and coal (43 percent). Several new generation units have been added to the SPP RTO fleet since the 2011 long-term reliability assessment, including 308 MW of wind, 552 MW of gas, and 168 MW of coal.

SPP-Table 4: Capacity Outlook[266]

	Current		2022 Planned			2022 Planned & Conceptual		
SPP-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	27,334	42.5%	27,380	40.7%	46	27,380	39.7%	46
Petroleum	1,919	3.0%	1,927	2.9%	9	1,927	2.8%	9
Gas	29,395	45.7%	30,990	46.0%	1,595	31,200	45.3%	1,805
Nuclear	2,409	3.7%	2,480	3.7%	71	2,626	3.8%	217
Other/Unknown	40	0.1%	50	0.1%	10	50	0.1%	10
Renewables	3,291	5.1%	4,511	6.7%	1,220	5,730	8.3%	2,439
TOTAL	**64,388**	**100.0%**	**67,338**	**100.0%**	**2,951**	**68,913**	**100.0%**	**4,525**



Future-Planned Expected on-peak capacity from renewable plants increases from 350 MW in 2013 to 1,220 MW in 2022. These reported renewable resource additions in the SPP RTO do not reflect merchant wind farm development in process, incremental needs that may result from Renewable Energy Standard mandates or goals within the SPP RTO region, or public announcements for additional renewable expansion by SPP RTO members. The SPP RTO has requests to interconnect approximately 14,109 MW of Future-Planned generation (mostly wind) to the SPP RTO grid via the generation interconnection queue.

Variable generation of 13,900 MW nameplate capacity comprises the majority of the Conceptual resources. SPP Criteria Section 12.0[267] discusses capacity values and how they are calculated for the Region based on a wind farm's historical performance. The SPP RTO applies a 10 percent confidence factor to all Conceptual capacity unless otherwise reported by SPP RTO members. Therefore, Conceptual Capacity Resources are forecast to be 1,045 MW in 2013, increasing to 1,575 MW in 2022.

For the reporting of Future and Conceptual Capacity Resources, the SPP RTO uses the Generation Interconnection and Transmission Service Request study processes as defined in the SPP OATT. According to the OATT, when the interconnection request is submitted, the interconnection customer must request either energy resource interconnection service or Network Resource interconnection service. Any interconnection customer requesting Network Resource interconnection service may also request that it be concurrently studied for energy resource interconnection service. This remains an option up to the point when an interconnection facility study agreement is executed. Interconnection customers may then elect to proceed with Network Resource interconnection service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed. In the NERC LTRA, the SPP RTO includes active requests that are currently in the generation queue to be studied, in addition to the member-reported Future, Planned, and Conceptual resources.

SPP RTO projects 929 MW of generation retirements over the 2013–2022 assessment time frame, not including retirements or derates that may occur in response to developing EPA regulations. The retirement of units is scheduled as follows: 130

[266] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[267] SPP Criteria: http://www.spp.org/publications/CRITERIA%20and%20Appendices%2001-25-2011Current.pdf.

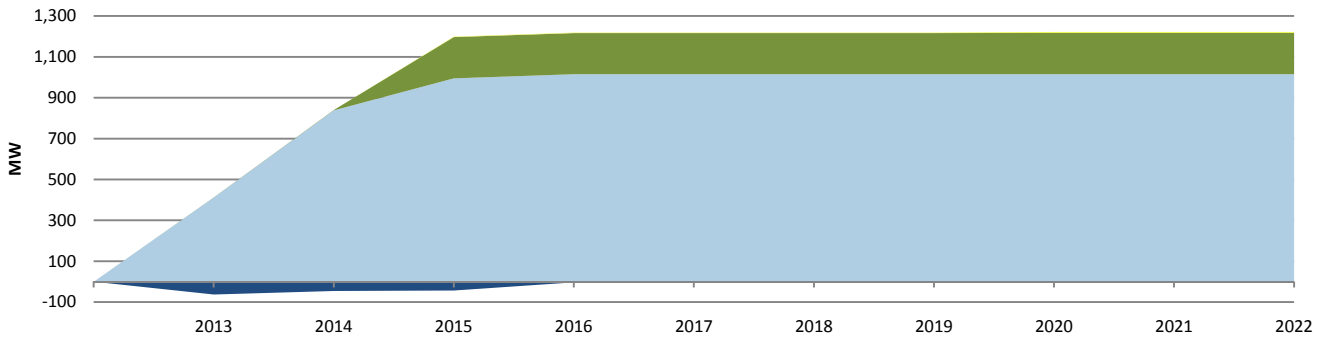
MW in 2013, 18 MW in 2015, 250 MW in 2016, and 531 MW in 2022. SPP RTO does not expect to have any reliability issues because of the projected retirements. With the new generation projected there are no operational or planning concerns at this time. There have been no project cancellations, and while some derates were reported from the previous year's assessment, they were not material.

The planned and conceptual renewable resources for the year 2022 are as follows: 2,505 MW of expected on-peak wind capacity with a maximum nameplate capacity of 28,069 MW, 13 MW of expected on-peak solar capacity with a maximum nameplate capacity of 90 MW, 2,673 MW of expected on-peak hydro capacity with a maximum nameplate capacity of 2,785 MW, and 221 MW of expected on-peak biomass capacity. The expected on-peak capacity values for this variable generation are determined by guidelines established in the SPP Criteria Section 12.0.

SPP-Table 5: Renewable Capacity Outlook[268]

	Current		2022 Planned			2022 Planned & Conceptual		
SPP-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	2,676	81.3%	2,673	59.2%	-3	2,673	46.6%	-3
Pumped Storage	319	9.7%	319	7.1%	0	319	5.6%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	273	8.3%	1,289	28.6%	1,016	2,505	43.7%	2,232
Biomass	19	0.6%	221	4.9%	202	221	3.9%	202
Solar	5	0.2%	10	0.2%	5	13	0.2%	8
TOTAL	**3,291**	**100.0%**	**4,511**	**100.0%**	**1,220**	**5,730**	**100.0%**	**2,439**

SPP-Figure 3: Summer Net Renewable Capacity Change



SPP-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
SPP-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	5,537	50	2,827	19	17,194	100	2,824	231
On-Peak Derate	5,264	45	152	0	15,905	90	152	10
EXPECTED ON-PEAK OUTPUT	273	5	2,676	19	1,289	10	2,673	221

SPP RTO evaluates operational procedures on an ongoing basis to determine if there are available improvements in efficiencies and reliability. Because of the level of wind resources in the footprint, SPP RTO is investigating the addition of wind into its automatic security constrained dispatch calculations. This would allow SPP RTO to better manage local congestion issues where wind is the primary impacting resource. It is anticipated that SPP RTO would then be able to manage system reliability by quicker and more effective control actions.

Capacity Transactions

SPP RTO members reported the following imports and exports for 2013–2022 (SPP-Table 7). These are Firm contracts that are backed by Firm transmission and generation.

[268] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

SPP-Table 7: Projected Capacity Transactions

SPP-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	2,247	2,408	2,408	2,408	2,458	2,458	2,488	2,488	2,488	2,488
TOTAL IMPORTS	2,247	2,408	2,408	2,408	2,458	2,458	2,488	2,488	2,488	2,488
Expected Exports	50	50	50	50	50	50	50	50	50	50
Firm Exports	2,338	2,307	1,997	1,997	2,067	2,034	2,034	2,034	2,034	2,043
TOTAL EXPORTS	2,388	2,357	2,047	2,047	2,117	2,084	2,084	2,084	2,084	2,093
TOTAL NET CAPACITY TRANSACTIONS	**-141**	**50**	**361**	**361**	**341**	**374**	**404**	**404**	**404**	**395**

SPP RTO members and some members of SERC have formed a Reserve Sharing Group. Group members receive contingency reserve assistance from each other; however, due to the high Reserve Margin in the SPP RTO footprint, group participants within SPP generally transfer reserves into SERC. Therefore, the group does not require support from generation resources located outside the SPP RTO region. The SPP RTO's Operating Reliability Working Group sets the Reserve Sharing Group's Minimum Daily Contingency Reserve Requirement. The Reserve Sharing Group maintains a minimum first contingency reserve equal to the generating capacity of the largest unit scheduled to be on-line, plus one-half of the capacity of the next-largest generating unit scheduled to be on-line.

Transmission

Appendix II lists the BPS transmission projects SPP RTO has defined as Under Construction, Planned, or Conceptual that are projected to be in service during the assessment time frame. Existing and projected transmission projects are summarized below (SPP-Table 8).

SPP-Table 8: Existing and Projected Transmission

SPP	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	32,881	0	32,881
Currently Under Construction	638	0	638
Planned - Completed within First Five Years	1,613	0	1,613
Planned - Completed within Second Five Years	180	0	180
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	35,311	0	35,311
Conceptual - Completed within First Five Years	47	0	47
Conceptual - Completed within Second Five Years	103	0	103
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**35,460**	**0**	**35,460**

There are several significant transmission projects involving upgrades to existing transmission lines for reliability purposes.

- In north-central Oklahoma, 45 miles of 69 kV line will be converted to 138 kV from Cottonwood to Crescent and from Cashion to Dover. In western Oklahoma, 44 miles of 69 kV from Anadarko to Franklin will be converted to 138 kV. In southwestern Oklahoma, the 33-mile Lindsay Flood Tap to Cornville 69 kV line will be converted to138 kV.
- In Kansas, there will be a 48-mile rebuild of a 115 kV line from St John to Medicine Lodge and 32 miles of 138 kV line from Medicine Lodge to Harper in south-central Kansas in the first five years of the assessment period. Additionally, in the last five years of the assessment period, the Kansas entities plan to rebuild the 33-mile Harper to Clearwater 138 kV line in this same Area. In the north-central Kansas Area, the 35-mile Clifton to Knob Hill 115 kV line will also be rebuilt. Kansas entities plan to rebuild 41 miles of 115 kV from Chapman–Abilene Energy Center to North Street in north-central Kansas.
- In the Texas panhandle, the 45-mile 69 kV Potter to Channing line will be converted to 115 kV during the first five years of the assessment. During the next five years of the assessment period, this line and an additional 35-mile line to Dallam is planned for conversion to 230 kV. In east Texas, 33 miles of 69 kV will be converted to 138 kV from Martinsville to Tempson.
- In Missouri, the 34-mile 161 kV line from Idalia to Poplar Bluff will be rebuilt.

The following projects are considered interregional interconnection-related projects:

- Stegall Project: Add a second 345/230 kV transformer at Stegall. The installation of this transformer requires a 3.3-mile tie line between the Stegall 230 kV and 345 kV substation. This project is to address low voltage at Victory Hill in southwest Nebraska for the loss of the first Stegall 345/230 kV.

- Gentleman–Cherry County–Holt: This project is a 345 kV multiline project through a large portion of central Nebraska. The Cherry County–Holt 345 kV line segment is proposed to interconnect with a WAPA 345 kV line. The construction of this project is driven by reliability needs, economic needs, and the need to meet renewable policies both in Nebraska and other areas in the SPP footprint.

The SPP RTO has sufficient transmission being constructed to meet the needs of the reported Future-Planned generation.

Appendix III contains a list of transformers projected to be in service during the assessment period.

Vulnerability Assessment

The impact of a long-term drought in the SPP RTO footprint would result in some loss of generation due to the unavailability of hydro generation and the loss of generation cooling water supplies. However, it is not anticipated that a long-term drought would impact reliability during the assessment period because SPP's geography is diverse and large portions of generation are not dependent upon single watersheds.

With the D.C. Circuit Court's decision to vacate CSAPR in August 2012, that regulation will no longer impact the SPP RTO footprint. However, the EPA's MATS regulation could result in generator retirements in the SPP footprint during the assessment period, and more detailed studies of the localized reliability impact will be conducted in response to official notifications of these retirements. In addition, there is a need to undertake coordination of outage scheduling around the compliance dates for new EPA standards, which may result in the need for limited compliance extensions. At this time and based on information provided to SPP RTO from members in March 2012, there are currently no scheduled long-term generator outages that could result in reliability concerns in the SPP RTO footprint.

EPA regulations may reduce the overall capacity margin within the SPP RTO, but some portion of that capacity is expected to be replaced due to an increase in renewable resources because of Renewable Portfolio Standards and state mandates. However, the replacement of that capacity with variable renewable technologies then raises reliability concerns of maintaining adequate frequency response, balancing control, and other reserve requirements. SPP RTO is participating in various standard development and research projects to determine any new requirements that may be necessary.

The projected level of Demand Response is not expected to have a significant impact on reliability during the next 10 years.

SPP RTO is evaluating the need for further requirements or standards that may be necessary to preserve reliability with increased levels of distributed, renewable generation such as rooftop solar and wind. The frequency response, balancing controls, and reserve requirement implications are the concern with these technologies.

SPP RTO is investigating the impact of requiring new variable generation installations to possess dispatch ability controls in order to allow the variable generation to respond to automatic security constrained dispatch instructions.

The SPP RTO only has one Under-Voltage Load Shedding program in western Arkansas within the AEP-West footprint. This program targets about 186 MW of load shed during peak summer conditions to protect the BPS from under-voltage events.

The SPP RTO has seven Special Protection Systems that are approved to be in place from 18 months to five years, based on the reliability need. All SPS requests are reviewed and approved by SPP's System Protection and Control Working Group, the Operating Reliability Working Group, and the Transmission Working Group.

SPP RTO has one SPS that was implemented in fall 2011 that is expected to be in service for three years. An automatic control system (ACS) was implemented to curtail a wind farm output to limit the flow on the MKEC Station–Cudahay line to 90 percent of the line rating under normal conditions. The SPS system would alleviate any overloads in the event of a system contingency or the failure of the ACS system. This temporary solution will be replaced with a permanent solution with the construction of a second 115 kV North Judson Large to Spearville line, which would eliminate the single contingency exposure to overloading the MKEC Station–Cudahay line. No SPS in SPP RTO was installed in place of planned bulk power transmission facilities.

While SPP RTO does not have a planning process in place at this time for catastrophic events, it does assess and study selected events as required by TPL-003 and TPL-004.

SPP RTO expects to implement its Day 2 market for its RTO footprint on March 1, 2014. This market, otherwise known as the Integrated Marketplace, will centralize unit commitment across 16 Balancing Authority (BA) Areas and consolidate operations to a single BA, known as the SPP RTO Consolidated Balancing Authority. SPP RTO will provide a five-minute security-constrained economic dispatch in order to provide real-time balancing activities while also providing centralized commitment of resources through the end of the operating horizon. It is expected that this structure will better allow SPP RTO to manage the variability of load and resources and provide additional flexibility in dealing with short-term reliability issues.

SPP RTO is also investigating centralizing the data gathering from several Phasor Measurement Units (PMU) systems within the footprint in order to enhance reliability analysis and situational awareness.

At this time, SPP RTO is in the early stages of investigating appropriate smart grid programs.

On a quarterly basis, SPP RTO reviews several years of SPP RTO Protection System misoperations data looking for trends that could be used to help reduce the number of misoperations in the future.

In December 2011, the U.S. Court of Appeals issued a stay of CSAPR that allowed SPP RTO staff to conduct a reliability impact assessment of the EPA MATS and CSAPR regulations (EPA Assessment) in early 2012. That assessment was based on members' preliminary expectations of how they currently plan to comply with both the CSAPR and the MATS. The EPA assessment indicated that for the years 2013 and 2015, outages associated with retrofits, deratings, revised dispatch, and retirements as a result of members' current expectations to comply with these regulations does have the potential for localized reliability violations but should not present footprint-wide negative reliability implications resulting from the assumptions used in the EPA's model.[269] Further, SPP analyzed the resource adequacy of the Region based on member EPA rules compliance expectations and, assuming no other negative circumstances in the SPP RTO footprint, resource adequacy appears to be sufficient. These conclusions could change if individual entities' underlying compliance planning changes.

Standing and Emerging Issues

Even with the decision to vacate CSAPR, the standing reliability issue that SPP RTO is most concerned about for the 10-year assessment period is the impact of the EPA MATS regulation as well as other developing environmental regulations on reserve margins and localized grid stability. On-going discussions with SPP RTO and EPA have recognized that ways of managing retrofits continues to be explored and these are being proactively managed. The SPP Operational Reliability Working Group has been tasked with oversight of a long-term outage coordination study to determine the impact of long-term outages to facilitate new environmental capture technologies and the expected retirements due to regulations. It is expected that the impact of these retirements and retrofits will begin to be experienced by 2015. The compressed compliance time frame provided for MATS will constrain the availability and increase the costs of qualified labor, materials and heavy equipment. These constraints, as well as the need to coordinate outage scheduling and complete localized transmission reinforcement projects, will likely demand that the compliance deadlines for certain units be extended. SPP RTO is maintaining regular contact with individual entities to ensure that any specialized assessments can be completed in time to identify and address circumstances in which additional time may be warranted. SPP RTO expects to complete an initial analysis of this issue by the end of 2012.

Capacity margins would be expected to decline throughout the SPP footprint, with at least some replacement capacity coming in the form of additional wind installations. However, wind as replacement capacity is subject to variability, inertia,

[269] The impacts identified in the study for 2013 will no longer be applicable with the CSAPR decision, but SPP RTO believes the MATS regulation will have similar impacts beginning in 2015 due to the four year compliance timeframe from the December 2011 finalization date of MATS.

and dispatch ability concerns. Lower capacity margins increase the exposure of the area to regional events such as those caused by extreme cold weather, droughts, widespread flooding, etc.

SPP RTO is also concerned about the dispatch ability of wind-powered resources. SPP RTO has been identified as an area rich with the hub height winds (the appropriate wind profile needed for the production of wind generation). While additional wind resources provide positive growth to the SPP RTO capacity margin, they also bring the issues associated with having a variable fuel supply. Also, without adequate requirements in place, new wind resources will not be equipped with the necessary primary frequency response, dispatch ability, or adequate voltage regulation controls. SPP RTO is participating in various forums to understand the implications and necessary actions to provide the appropriate requirements not just for wind resources, but all new generation technologies. There could be anywhere from 10,000 to 24,000 MW of nameplate wind resources forecast to be built within the SPP Region over the next 10 years. This includes wind that SPP RTO concludes to be Future-Planned and Conceptual. SPP's Integrated Transmission Planning process is taking into account the additional transmission needs of new wind resources.

Finally, SPP RTO and other affected parties are reviewing studies performed by Clean Line Energy for HVdc lines proposed to traverse across SPP from west to east. The first project, the Plain and Eastern line, is a 3,500 MW capacity, 700-mile HVdc facility that is planned to begin in western Oklahoma and end in western Tennessee.[270] The second Clean Line Energy project, the Grain Belt Express Line, is a 3,500 MW, 700-mile HVdc facility planned between Kansas and Missouri

SPP and other affected parties are also reviewing studies performed by Tres Amigas for its proposed construction of an HVdc transmission facility that will link America's three primary electric transmission grids: the Eastern Interconnect (SPP, MRO, etc.), the Western Interconnect (WECC) and Texas (ERCOT).[271]

Both Clean Line Energy projects and the Tres Amigas project are in the planning stages. No Firm in-service dates are known for the Clean Line projects, but Tres Amigas expects Phase 1 (750 MW) of its project to be in service by March 2015. As stated above, SPP has begun the technical evaluation of these projects. Should the proposed facilities be constructed and placed in service, SPP may be faced with a large number of transmission requests. SPP may not be able to approve all of the requests until additional transmission facilities are built. However, SPP's current processes should prevent any reliability impact to the BES.

[270] http://www.plainsandeasterncleanline.com/site/home
[271] http://tresamigasllc.com/index.php

WECC

Planning Reserve Margins

The Planning Reserve Margins, or target margins, were derived using the 2013 load forecast and the same method as the 2011 Power Supply Assessment (PSA).[272] The PSA uses a building block method for developing the Planning Reserve Margins and has four elements:

- Contingency reserves
- Operating reserves
- Reserves for forced outages
- Reserves for one-year-in-ten weather events

By the summer of 2022, the difference between WECC's Anticipated Resources (194,401 MW) and WECC's Net Internal Demand (168,973 MW) is anticipated to be 25,429 MW (15.0 percent margin). This would be 759 MW above the target margin. Since the expected capacity resources result in margins that exceed target margins, it is reasonable to assume that only a portion of the reported resource additions will ultimately enter commercial service within the planning horizon.

WECC does not have an interconnection-wide formal Planning Reserve Margin standard. As previously mentioned, the WECC annual PSA summer and winter reserve target margins are developed using a building block method.

As depicted in the subregional tables, found at the end of the WECC section, the Anticipated, Prospective, and Adjusted Potential Reserve Margins for the WECC Assessment Area remain above NERC Reference Margin Level throughout the 2013–2022 planning horizon. However, individual subregions do drop below the target in future years.

NERC's assessment process treats Demand Response (DR) programs as sharable between Load-Serving Entities (LSE), Balancing Authorities (BA), and subregions. However, DR programs in WECC generally have limitations, such as having a limited number of times they can be called. Some can only be called during a declared local emergency. Consequently, Planning Reserve Margins may be overstated, as these margins do not consider the potential unavailability of DR for external energy emergencies. Many LSEs within WECC largely treat DR as a safety net that is available if circumstances such as unexpected generator-forced outages or extreme temperature events result in unexpected low operating margins.

In the resource adequacy process, each BA is responsible for complying with the resource adequacy requirements of the state or provincial areas in which they operate. Some BAs perform resource adequacy studies as part of their Integrated Resource Plans, which usually provide a 20-year outlook. Other BAs perform resource adequacy studies that focus on the very short-term (1-2 years), but most projections provide at least a 10-year outlook. WECC's PSA uses a study period of 10 years and uses the same zonal reserve target margins throughout the entire period. These target margins are applied as the NERC Reference Margin Level for each WECC subregion.

Similar to WECC's PSA, resources that are energy-only or energy-limited resources (e.g., the portion of wind resources that is not projected to provide generation at the time of peak) are not counted toward meeting resource adequacy in this assessment. Also, resources such as distributed or behind-the-meter generation that are not monitored by the BA's energy management systems are excluded from the resource adequacy calculation.

Demand

Total Internal Demand for the summer, the peak season for the entire WECC Assessment Area, decreased by 0.8 percent from 2010 to 2011. Summer temperatures in both 2010 and 2011 were normal to slightly warmer than normal which indicates actual demand reduction is associated with the continued slow economic recovery. The projected 2013 and 2022 Total Internal Demand forecasts and compound annual growth rates are presented in the following tables.

[272] WECC's Power Supply Assessment: http://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/Forms/AllItems.aspx.

Demand Outlook – WECC Total

WECC-Total-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	144,936	168,973	24,036	16.6%	1.72%
Load-Modifying Demand Response	5,041	5,583	542	10.8%	1.14%
TOTAL INTERNAL DEMAND	**149,977**	**174,556**	**24,578**	**16.4%**	**1.70%**

WECC-Total-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	132,006	150,429	18,423	14.0%	1.46%
Load-Modifying Demand Response	2,018	2,385	367	18.2%	1.87%
TOTAL INTERNAL DEMAND	**134,024**	**152,814**	**18,790**	**14.0%**	**1.47%**

The Total Internal Demand for the summer season is projected to increase by 1.7 percent per year for the 2013–2022 timeframe, which is unchanged from the 1.7 percent projected last year for the 2012–2021 period. The annual energy load is projected to increase by 1.6 percent per year for the 2013–2022 timeframe, which is unchanged from the 1.6 percent projected last year for the 2012–2021 period.

Demand-Side Management

The total WECC internal demand forecast includes summer DR that varies from 5,041 MW in 2013 to 5,583 MW in 2022. The direct control DSM capability is located mostly in the CALN and CALS subregions, totaling 2,812 MW in 2013 and 3,131 MW in 2022, but DSM programs in other subregions are also increasing. The most prevalent DR programs in WECC involve air conditioner cycling as well as interruptible load programs that focus on the demand of large water pumping operations and large industrial operations such as mining. The most significant current DR development activity within WECC is occurring in California where the California ISO (CISO) is actively engaged with stakeholders in developing viable wholesale DR products with direct market participation capability. Also of note is the CISO's new DR product implementation that facilitates the participation of existing retail demand programs in the CISO market. Further information regarding these initiatives is available at the CISO website.[273]

Projected Demand-Side Management – WECC Total

	Short-Term					
WECC-Total-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	2,023	2,103	2,125	2,144	121	1.12%
Contractually Interruptible (Curtailable)	1,836	1,923	1,971	2,023	187	1.06%
Critical Peak-Pricing (CPP) with Control	7	12	13	16	9	0.01%
Load as a Capacity Resource	1,175	1,099	1,115	1,400	225	0.73%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	5,041	5,137	5,224	5,583	542	2.92%
TOTAL ENERGY EFFICIENCY	1,150	1,749	2,418	6,859	5,709	3.59%
TOTAL DEMAND-SIDE MANAGEMENT	**6,191**	**6,886**	**7,642**	**12,442**	**6,251**	**6.51%**

Generation

The generation data for this assessment was provided by all of the BAs within the Western Interconnection and was processed by WECC staff under the direction of the WECC Loads and Resources Subcommittee (LRS). The reported generation additions generally reflect extractions from generation queues.

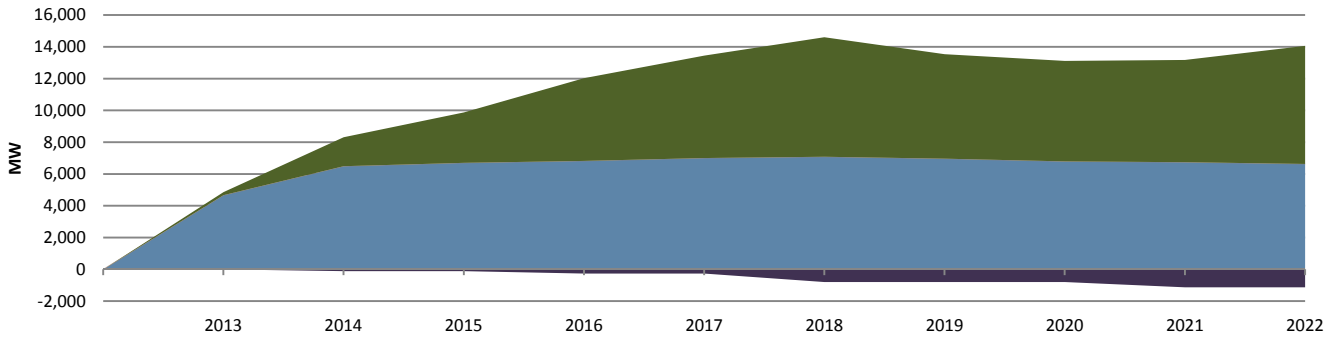
Distributed generation, including rooftop solar and behind-the-meter generation, represents an insignificant portion of both the existing and planned resources. As noted previously, these resources are excluded from the resource adequacy calculation (i.e., they are not included as resources). The current resource mix by fuel type includes natural gas, hydro-powered, and coal-fired generation at 87,769 MW, 61,439 MW, and 35,069 MW, respectively.

Since last year's assessment, expected available capacity increased by 363 MW. Thermal plant additions were largely gas-fired combined-cycle plants, while renewable additions were largely wind farms.

[273] CAISO Demand Response Initiatives: http://www.caiso.com/1893/1893e350393b0.html.

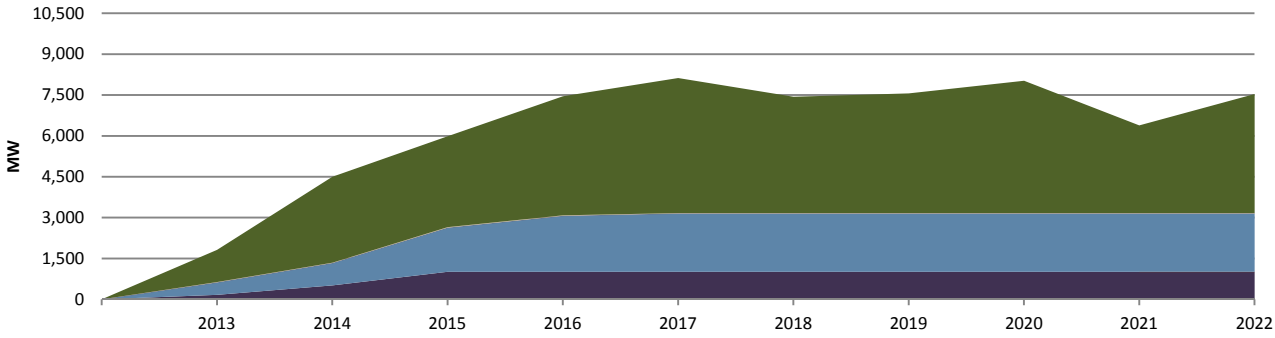
Capacity Outlook– WECC-US[274]

WECC-US-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Coal	29,333	17.9%	28,188	16.1%	-1,145	28,188	15.3%	-1,145
Petroleum	1,084	0.7%	1,084	0.6%	0	1,004	0.5%	-80
Gas	79,303	48.5%	85,055	48.4%	5,752	91,811	49.8%	12,508
Nuclear	9,553	5.8%	9,553	5.4%	0	9,553	5.2%	0
Other/Unknown	52	0.0%	52	0.0%	0	52	0.0%	0
Renewables	44,229	27.0%	51,655	29.4%	7,426	53,615	29.1%	9,386
TOTAL	**163,553**	**100.0%**	**175,586**	**100.0%**	**12,033**	**184,222**	**100.0%**	**20,669**



Capacity Outlook– WECC-CAN[275,276]

WECC-CAN-Winter	Current Capacity Mix	Current Share of Total	2022/23 Planned Capacity Mix	2022/23 Planned Share of Total	2022/23 Planned Change	2022/23 Planned & Conceptual Capacity Mix	2022/23 Planned & Conceptual Share of Total	2022/23 Planned & Conceptual Change
Coal	5,811	21.6%	6,655	19.4%	844	6,655	18.4%	844
Petroleum	0	0.0%	0	0.0%	0	0	0.0%	0
Gas	6,794	25.2%	8,904	26.0%	2,110	10,781	29.9%	3,988
Nuclear	0	0.0%	0	0.0%	0	0	0.0%	0
Other/Unknown	22	0.1%	26	0.1%	4	26	0.1%	4
Renewables	14,282	53.1%	18,653	54.5%	4,371	18,653	51.6%	4,371
TOTAL	**26,909**	**100.0%**	**34,238**	**100.0%**	**7,329**	**36,115**	**100.0%**	**9,206**



Gross Future-Planned additions are 12,033 MW for the United States, and 7,329 MW for Canada. Conceptual additions amount to 20,669 MW and 9,206 MW for the United States and Canada, respectively.

Three utilities attributed coal-fired plant retirements totaling 1,050 MW and fuel conversions totaling 295 MW to existing air emissions regulations. Based on information related to western coal-fired plant environmental regulation cost

[274] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[275] *Ibid*.
[276] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

exposure,[277] it is expected that next year's LTRA information will report additional retirements and fuel conversion as more plant owners establish their preferred approaches to address the recent Maximum Achievable Control Technology regulations. Due to the somewhat fluid situation in California regarding retirements associated with once-through cooling (OTC) regulations, potential associated capacity reductions have not been reported for this year's LTRA. Current information regarding the California OTC is available on the California Energy Commission's website.[278]

It is expected that the WECC Region will not experience significant resource capability changes due to plant rating changes, plants being temporarily removed from service, new "non-traditional" resource acquisitions, or changes in behind-the-meter generation.

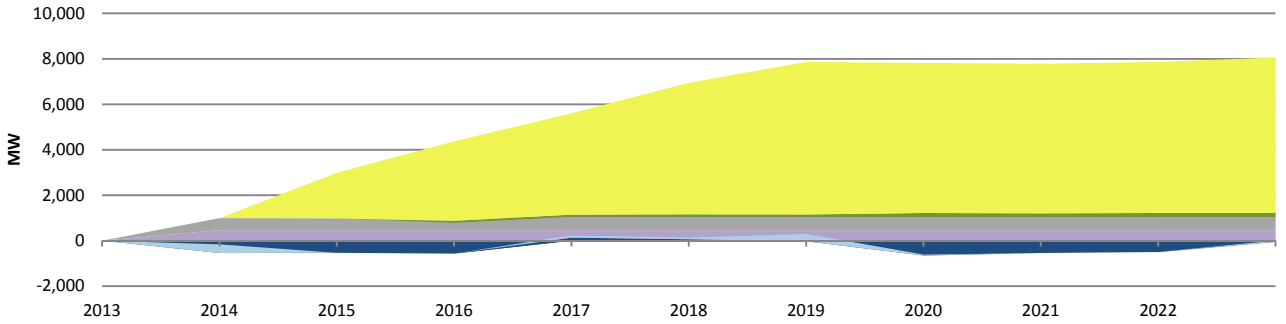
The projected summer peak-period Existing-Certain and Future-Other resources value 2013 of 182,873 MW reflects the monthly shaping of variable generation and the seasonal ratings of conventional resources. The resources not counted toward on-peak capacity include 45,791 MW of variable generation derates and 10,264 MW of scheduled outages. Hydro derates reflect an assumed adverse hydro condition and is dispatched economically limited to a specified annual energy output. Wind derates are based on wind capability curves created using three years' worth of one-hour interval wind speed data while solar production curves were created using two years of solar insolation data.

The individual BAs report the net Future-Planned Capacity Resources projected to be placed into service by the end of this assessment period as 19,361 MW.Greater wind generation has resulted in an increased fluctuation in instantaneous generation and a need for increased operating reserves to compensate for the wind-induced fluctuations. Improved wind forecasting procedures and reduced scheduling intervals have only partially addressed the issue. Increased wind generation has also exacerbated high generation issues in the Bonneville Power Administration (BPA) Area during light load and high hydro-electric generation conditions. BPA is working on long-term solutions to this issue and makes current information regarding the issue available on its website.[279] Increased wind penetration is expected to exacerbate the operating reserve situation.

[277] Environmental Controls and the WECC Coal Fleet: http://www.wecc.biz/committees/BOD/TEPPC/TAS/SWG/10March2011/Lists/Minutes/1/WGG_Coal_Plant_Database_Documentation_Final.pdf.
[278] CEC Once-Through Cooling: http://www.energy.ca.gov/siting/once_through_cooling.html.
[279] BPA Wind Activities http://transmission.bpa.gov/wind/.

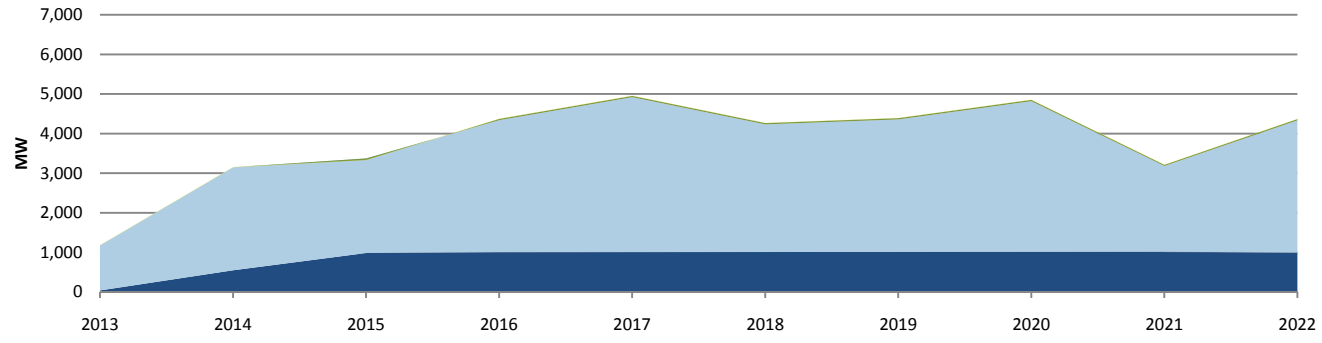
Renewable Capacity Outlook[280]

WECC-US-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Hydro	34,505	78.0%	34,457	66.7%	-48	34,481	64.3%	-24
Pumped Storage	4,872	11.0%	4,887	9.5%	15	5,277	9.8%	405
Geothermal	2,087	4.7%	2,478	4.8%	392	3,227	6.0%	1,141
Wind	317	0.7%	371	0.7%	54	411	0.8%	94
Biomass	802	1.8%	977	1.9%	175	980	1.8%	178
Solar	1,646	3.7%	8,485	16.4%	6,839	9,239	17.2%	7,592
TOTAL	**44,229**	**100.0%**	**51,655**	**100.0%**	**7,426**	**53,615**	**100.0%**	**9,386**



WECC-CAN-Winter	Current Capacity	Current Share	2022/23 Planned Capacity	2022/23 Planned Share	2022/23 Planned Change	2022/23 Planned & Conceptual Capacity	2022/23 Planned & Conceptual Share	2022/23 Planned & Conceptual Change
Hydro	12,836	89.9%	13,835	74.2%	999	13,835	74.2%	999
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	1,173	8.2%	4,513	24.2%	3,341	4,513	24.2%	3,341
Biomass	273	1.9%	305	1.6%	31	305	1.6%	31
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**14,282**	**100.0%**	**18,653**	**100.0%**	**4,371**	**18,653**	**100.0%**	**4,371**

Renewable Capacity Outlook[281]



[280] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[281] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

WECC-Total-Table 8: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
WECC-TotalL-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	17,249	2,725	66,984	1,944	30,649	15,738	69,032	3,287
On-Peak Derate	16,893	1,079	19,969	872	29,511	6,144	20,574	2,029
EXPECTED ON-PEAK OUTPUT	356	1,646	47,016	1,072	1,138	9,595	48,458	1,257

Capacity Transactions

WECC does not rely on imports from outside the Assessment Area when calculating peak demand reliability margins. The Assessment Area also does not model exports to areas outside of WECC. However, imports may be scheduled across three back-to-back dc ties with the Southwest Power Pool, Inc. (SPP) and five back-to-back dc ties with the Midwest Reliability Organization (MRO). One WECC entity reports a 101 MW diversity exchange credit with its counterpart in SPP, but this exchange is not reflected in this assessment. WECC does not model "emergency generation" as being available to meet the NERC Reference Margin Level.

Inter-subregional transfers are derived from resource allocation computer simulations that incorporate transmission constraints among various path-constrained zones within WECC. The WECC resource allocation model places conservative transmission limits on paths between 20 load groupings (bubbles) when calculating the transfers between these areas. These load bubbles were developed for WECC's PSA studies. The aggregation of PSA load bubbles into WECC subregions may obscure differences in adequacy or deliverability between bubbles within the subregion. Hence, the resource data for the individual subregions include transfers between subregions that are either plant-contingent transfers or reflect projected economic transfers with a high probability of occurrence. The plant-contingent transfers represent both joint-plant ownership and plant-specific transfers from one subregion to another.

The projected economic transfers reflect the potential use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking southwest, as well as other economy and short-term Firm purchases that may occur between subregions.

Despite the fact that these transactions may not be contracted, they reflect a reasonable modeling expectation given the history and extensive activity of the western markets, as well as the otherwise underused transmission from the northwest to the other subregions. When using the adjusted potential resource mixes, all of the subregions are able to maintain adequate reserves.

A process similar to the one used to determine regional and subregional target margins was used to determine the inter-subregional transfers. The various area bubbles used were combined into the appropriate WECC subregions, and the excess or deficit capacity was summed for each of the WECC subregions. The excess or deficit capacity was then used to calculate the amount of projected purchases or projected sales transactions between the various subregions.

Western entities participate in shorter-term power markets for which forecasts are not available. This is a primary reason the WECC analysis uses the simulation process described above to determine the projected transfer values. The Western Systems Power Pool contract, which contains liquidated damage provisions, is heavily relied upon as the template for such transactions.

Transmission

WECC is spread over a wide geographic area with significant distances between generation and load centers. In addition, the northern portion of the Assessment Area is winter peaking, while the southern portion of the assessment area is summer-peaking. Consequently, entities within the Western Interconnection may seasonally exchange significant amounts of surplus electric energy. These conditions result in periodic full loading on numerous transmission lines, but that full loading is deemed not to adversely impact reliability. Due to the inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

AC transmission line additions through 2022 have been reported at 15,841 circuit miles and 535 circuit miles of DC transmission. The reported existing and projected transmission additions are compiled in the following table (WECC-Total-Table 8).

WECC-Total-Table 8: Existing and Projected Transmission

WECC-Total	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	127,019	1,744	128,763
Currently Under Construction	199	0	199
Planned - Completed within First Five Years	5,784	535	6,319
Planned - Completed within Second Five Years	4,501	0	4,501
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	137,503	2,279	139,782
Conceptual - Completed within First Five Years	2,759	0	2,759
Conceptual - Completed within Second Five Years	2,598	0	2,598
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**142,860**	**2,279**	**145,139**

There are a large number of transmission projects that have been reported to WECC. Some of these projects are duplicative in nature and may have a proposed path similar to another project. Since WECC does not vet the reported new projects and does not identify minimum transmission addition needs, the above tabulation may not closely reflect transmission additions that could occur during the assessment period. A delay of these projects could impact the timing and location of resource additions but should not adversely impact system reliability. The subregion sections of this assessment may identify some projects that could impact local area reliability. The WECC Transmission Project Information Portal[282] provides a single location where interested parties can find basic information about major transmission projects in the Western Interconnection.

WECC's Transmission Expansion Planning Policy Committee's (TEPPC) Subregional Coordination Group has analyzed the development status of reported major transmission projects and identified 30 projects that have a high probability of being in service by 2022. Information regarding the projects is available in the group's report *2022 Common Case Transmission Assumptions* (CCTA).[283]

To help monitor the impact of new generation resources on the transmission systems, individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify any adverse impact from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure are located in WECC's *Policies and Procedures for Project Coordination Review, Project Rating Review, and Progress Reports*.[284] These processes identify potential deliverability issues that may result in actions such as the implementation of system protection schemes designed to enhance deliverability and to mitigate possible adverse power system conditions.

WECC has signed an agreement with the U.S. Department of Energy to receive a $53.9 million grant for the Western Interconnection Synchrophasor Program (WISP). The funding allows an accelerated installation of more than 250 new Phasor Measurement Units (PMUs) in the Western Interconnection. The PMUs are designed to alert operators to existing and potential problems on the grid and improve the ability to integrate and manage intermittent renewable resources in the west. The synchrophasor infrastructure and associated software applications and tools are expected to improve situational awareness, system-wide modeling, performance analysis, and wide-area monitoring and controls. Further information regarding the WISP program is available on the WECC website.[285]

Growth in demand combined with increases in projected new generation has resulted in the need for significant transmission system upgrades and expansion. Because of the longer lead time required for transmission permitting and

[282] WECC Transmission Project Information Portal: http://www.wecc.biz/PLANNING/TRANSMISSIONEXPANSION/MAP/Pages/.
[283] 2022 Common Case Transmission Assumptions (CCTA): http://www.wecc.biz/committees/BOD/TEPPC/External/SCG_CCTA_Report.pdf.
[284] WECC's Overview of Policies and Procedures for Project Coordination Review, Project Rating Review and Progress Reports: http://www.wecc.biz/committees/StandingCommittees/PCC/Shared%20Documents/ProjectCoordination_ProjectRating_ProgressReports_approved%203-11.aspx.
[285] WECC WISP web site: http://www.wecc.biz/awareness/Pages/WISP.aspx.

construction, network planning focuses on establishing a flexible grid infrastructure. This is being done with the goal of accommodating internal power movement from generation sources to load centers.

Planning efforts continue on a number of major system reinforcements, including supply into the Fort Saskatchewan and Fort McMurray Areas of northeast Alberta. This reinforcement will likely be a combination of 500 kV and 240 kV developments. Planning efforts are also continuing on reinforcing the main north-south transmission grid in Alberta. The Edmonton–Calgary Transmission Reinforcement project calls for two high-capacity lines between the north and south of the province to reinforce the backbone of the grid. It is anticipated that this project will be in-service by the end of 2014.

Alberta Electric System Operator (AESO) has an Under-Voltage Load Shedding (UVLS) scheme. There are approximately 300 MW of load currently connected to the UVLS. Activation of the scheme is not expected to adversely impact other load within the AESO subregion.

A Calgary-Area transmission must-run procedure addresses 240 kV transmission grid-loading issues and ensures voltage stability margins are maintained. The transmission must-run procedure is an ancillary service contract with generators that is required to address contingencies in areas of inadequate transmission to help provide voltage support to the transmission system in southern Alberta (near Calgary) and assist in maintaining overall system security.

Transmission owners in the subregion have started construction on significant grid reinforcements and enhancements to support intra-regional power transfers and exports of wind generation.

Power flow studies have been conducted by the transmission planning authorities, and in some cases where there have been critical contingencies identified, mitigation measures (e.g., adding reactive sources) or new facilities (e.g., adding a new transformer) have been proposed. Because some of these improvements are driven by future load growth or requests not yet firmed up by the customers, some of these measures have not yet escalated to the project level, and no specific date for their completion has been assigned.

Because of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goal of accommodating internal power movement from generation sites to load centers.

Analysis of WECC's 2011 PSA results indicates that economic diversity exchanges may result in full loading of the transmission interconnections between the United States and Canadian portions of the NWPP during winter peak periods. British Columbia (WECC-BC) is traditionally a net exporter with projected exports expected to remain relatively constant throughout the study period.

The WECC-BC subregion relies on hydro-electric generation for 90 percent of its energy production. British Columbia Hydro and Power Authority (BCHA) is responsible for the planning, operation, and maintenance of British Columbia's publicly-owned transmission system. BCHA is addressing constraints between remote hydro plants and the Lower Mainland (LM) and Vancouver Island (VI) load centers.

A key transmission constraint in the WECC-BC subregion is the Interior-to-Lower Mainline (IML) path. The ILM Transmission Project[286] is the province's largest expansion project in 30 years. In August 2008, the British Columbia Utility Commission approved the ILM Project, which is a new 500 kV line between the Nicola and Meridian substations, with a projected in-service date in 2014.

BCHA is planning to rely on the existing 905 MW conventional steam plant located in the major load center and the 1,250 MW Canadian entitlement from the Northwestern United States (WECC-NWPP) to meet the Lower Mainland resource requirements in the interim period.

[286] Interior to Lower Mainland (ILM) Transmission Project: http://www.bchydro.com/energy_in_bc/projects/ilm.html.

BCHA has UVLS schemes installed for the LM and V I systems to prevent voltage collapse. These schemes monitor the voltage at the key substations in LM and VI a and the Var reserves at VI transmission synchronous condensers and Burrard Generation Station. If the voltages and the Var reserves are lower than the settings, the selected loads in LM and VI will be removed from service. The maximum load-shedding amount is about 1,690 MW. At this time, BCHA does not anticipate the installation of any additional UVLS schemes.

The 500 kV bulk transmission systems in northern California consist of three parallel 500 kV lines that traverse the state from the California–Oregon border in the north and continue south to the Vincent substation in southern California. This system transfers power between California and other states in the northwest. The interconnection at the northern end is identified as Path 66, or the California–Oregon Intertie. The system also interconnects with northern California hydro-electric generation for delivery to population centers in the San Francisco Bay Area and the Central Valley Area. Further south, the 500 kV lines interconnect with a large number of generation resources in central California. At the Vincent substation, the 500 kV lines interconnect with the Southern California Edison (SCE) 500 kV transmission system. That interconnection point is identified as Path 26.

The Reliability Assessment section of the CISO's 2011–2012 Transmission Plan[287] examined power flow studies, transient stability analysis, and voltage stability studies to identify facilities that indicate the potential of not meeting applicable performance requirements. For the backbone system assessment (500 kV and select 230 kV facilities), conventional and governor power flow studies and stability studies were performed to evaluate the system performance under normal conditions and following the contingencies of power system equipment of voltage levels 230 kV and above. For the local area non-simultaneous assessments, conventional and governor power flow studies were performed under normal system conditions and contingency system conditions of power system equipment of voltage levels 60 kV through 230 kV. These assessments were performed for eight local Pacific Gas & Electric Company service territory areas.

The California-South (CALS) subregion is connected to the California-North subregion by three 500 kV transmission lines. Additional California-South interconnections include a 500 kV dc transmission line to north-central Oregon, a 500 kV dc transmission line to the Intermountain Power Plant in central Utah, a few 230 kV ties to Baja California, Mexico, and numerous 500 kV and lower voltage ties to Arizona and southern Nevada. These numerous interconnections allow the subregion to be a net importer of significant amounts of power. As discussed in the California-North transmission assessment narrative, the CISO prepares an annual transmission plan. That plan addresses San Diego Gas & Electric Company's (SDG&E) service territory and seven local SCE service territory areas. In June, SDG&E placed into service a new 500 kV transmission line linking San Diego and Imperial Valley. The line, initially rated at 800 MW, will help support the CALS Area during the San Onofre nuclear plant outage. Ultimately, the line will support the transfer of up to 1,000 MW of power from the renewable-rich Imperial Valley Area.

Transmission providers from the Desert Southwest subregion, along with other stakeholders from southern California, are actively engaged in the Southwest Transmission Expansion Planning (STEP) group. The goal of this group is to collaborate in the planning, coordination, and implementation of a robust transmission system interconnecting Arizona, southern Nevada, Mexico, and southern California that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. The STEP group has developed three projects resulting from the study efforts to upgrade the transmission path from Arizona to southern California and southern Nevada. The three projects will increase the transmission path capability by about 3,000 MW. The first set of upgrades was completed in 2006 and increased the transfer capacity by 505 MW. The second set of upgrades will increase the transfer capacity by 1,245 MW, and many of the upgrades have been completed. The final set of upgrades is the Palo Verde–Devers #2 500 kV transmission line (PVD2) addition. The final set of upgrades encountered complications in 2007 with the Arizona Corporation Commission's refusal to grant a permit for the construction of the PVD2 line. In May 2009, SCE dropped the

[287] CISO 2011-2012 Transmission Plan: http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf.

Arizona portion of the proposed line and announced that it would proceed to construct the California portion. During the years that the line has been proposed, the resource situation changed drastically, and SCE now believes that the California portion of the line is useful for central station solar projects being planned for the eastern portion of the state.[288]

For the Northwest subregion, additional time required for transmission permitting and construction requires recognition that network planners should focus on establishing a flexible interconnected transmission infrastructure. This is being accomplished with the goals of accommodating anticipated transfers among systems, addressing several areas of constraint within Washington, Oregon, Montana, northern Idaho, and other areas within the Assessment Area, and integrating new generation. Projects at various stages of planning and implementation include approximately 758 miles of 500 kV transmission lines.

Maintaining the capability to import power into the Northwest subregion during infrequent extreme cold weather periods continues to be an important component of transmission planning and operations. Under certain transmission system outage conditions, the Northwest subregion depends on an automatic Under-Frequency Load Shedding (UFLS) scheme to support maximum import transfer capabilities.

Some BAs have taken steps to help make the transmission queue assessment processes more efficient. For example, BPA instituted a process called the Network Open Season (NOS) for allowing resources placement in its transmission queue. Under the NOS, those seeking transmission capacity are asked to sign Precedent Transmission Service Agreements (PTSA) that commit them to taking service at a specified time and under specified terms. At one time, BPA's transmission queue was over 18,000 MW. After the first phase of the 2008 NOS, there were 6,410 MW worth of transmission requests made and PTSAs signed by customers. The PSTA contract is still contingent on BPA's ability to offer new service at its embedded cost rate and is subject to BPA's completion of the required environmental work prior to construction of new facilities.

Tri-State Generation and Transmission is proposing a project in southern Colorado called the San Luis Valley Electric System Improvement project. The project would involve the construction of an 80-mile 230 kV transmission line between the Walsenburg substation and the San Luis Valley substation. The San Luis Valley's existing electrical system has reached its limit due to continued residential and irrigation growth. One major concern is that the radial nature of the existing 230 kV transmission system does not provide the reliability benefits of redundant service. The other major problem currently experienced on the transmission system is a drop in voltage that occurs when the load on the electric system in the valley is above 65 MW. This line will provide the power delivery infrastructure to increase the reliability and capacity of the existing transmission system and support proposed renewable energy development in the area.

The Western Area Power Administration (WAPA) is upgrading several 115 kV transmission lines to 230 kV over the next several years to increase transfer capabilities and help maintain the operating transfer capability between southeastern Wyoming and northeastern Colorado.

There were no significant transmission additions in the WECC-Mexico subregion.

Vulnerability Assessment

Hydro systems within the Western Interconnection are exposed to drought conditions that may adversely impact electric power generation. The adverse impact includes both reduced energy generation and reduced operating flexibility in maximizing generation during high-peak demand periods. However, since the bulk of the river flows are driven by snowfall, system operators have sufficient time to prepare operational plans consistent with seasonal river runoff forecasts.

Due to the strength of the interconnected power grid, WECC has not experienced significant reliability issues related to long-term generator outages, and possible future long-term plant outages are not a concern relative to long-term reliability planning.

[288] Palo Verde-Devers: http://www.cpuc.ca.gov/environment/info/aspen/dpv2/dpv2.htm.

Renewable Portfolio Standards (RPS) have resulted in significant increases in installed wind-powered generation and planned wind and solar generation additions. WECC's TEPPC is actively evaluating long-term regional transmission needs that factor in the expanding role of these variable generation resources. Further information regarding that work is available on the WECC website.[289]

Due to limited size and program design, a lack of DR action during activation events has not been an issue and, due to the limited growth in such programs, is generally not expected to be a significant issue during the assessment period. It should be noted, however, that the CISO is actively engaging stakeholders in developing viable wholesale DR products with direct market participation capability. The CISO's website presents current information about its Demand Response initiative.[290]

Distributed generation has historically not been a significant resource in WECC. While the Assessment Area has experienced an increase in distributed solar generation, any associated impact has been essentially limited to the local power distribution facilities, and further expansion of solar-distributed generation is not expected to significantly impact the interconnected power system.

As noted in the preceding RPS discussion, entities within the Assessment Area are addressing long-term transmission effects related to increased variable generation. It is expected that processes to address other operational issues, such as over-generation during light load periods, will be addressed by affected entities on a when-needed and where-needed basis (e.g., Bonneville Power Administration's over-generation issue).[291]

After the July 2 and August 10, 1996 disturbances that caused cascading outages of transmission and generation and a widespread loss of customer load within WECC, the technical groups evaluating those events recommended a number of action items to enhance interconnected system reliability. One of those action items was that WECC member systems should evaluate the need for UVLS and report to WECC regarding the implementation of UVLS on their individual systems.

Other documents supporting the call for UVLS studies were the NERC report "Survey of Voltage Collapse Phenomenon (August 1991)," the NERC Planning Standards (approved September 1997) and the WECC "Policy Regarding Extreme Contingencies and Unplanned Events".[292] The WECC policy in particular places strong emphasis on the application of Safety Nets to protect the system from unplanned events outside the performance levels defined under the WECC Reliability Criteria. UVLS is one of the Safety Net schemes identified under the WECC policy.

To assist member systems on how to perform UVLS studies to comply with the WECC mandate, the Technical Studies Subcommittee (TSS) formed an Under-Voltage Load Shedding Task Force (UVLSTF) with a direction to:

- Develop guidelines for the member systems to determine if they would benefit from UVLS either as a Remedial Action Scheme or as a Safety Net
- Prepare application guidelines to design UVLS systems
- Develop methodologies to study and implement UVLS

WECC addressed the UVLS issue in the "Under-Voltage Load Shedding Guidelines" document approved by WECC's Technical Studies Subcommittee April 28, 2010.[293]

The power transfer capabilities of most major subregion transmission interconnections within WECC are limited by system stability constraints rather than by thermal limitations. These stability constraints are sensitive to system conditions and may often be increased significantly at nominal cost by applying SPS or remedial action scheme. The future use of such

[289] WECC Regional Transmission Expansion Planning: http://www.wecc.biz/Planning/TransmissionExpansion/RTEP/Pages/default.aspx.
[290] California ISO - Demand Response Initiative: http://www.caiso.com/1893/1893e350393b0.html.
[291] BPA Wind Activities: http://transmission.bpa.gov/wind/.
[292] Approved October 1997; see Appendix C.
[293] WECC Undervoltage Load Shedding Guidelines http://www.wecc.biz/library/Documentation%20Categorization%20Files/Guidelines/Undervoltage%20Load%20Shedding%20Guidelies%20-%20Guideline.pdf.

relatively inexpensive schemes in lieu of costly transmission facility additions, and whether they will be permanent or temporary additions, will depend on as-yet-undetermined system conditions.

WECC has not established a planning process that addresses high-impact, low-probability events. However, various entities within WECC do take such possibilities into consideration, depending on conditions most pertinent to their respective geographic areas. For example, transmission planners in northern areas consider loading on transmission lines under severe ice storm conditions. High-wind areas are also addressed in facility designs, as is earthquake potential, etc.

LSEs within WECC have been rapidly expanding the use of smart meters and the associated interface equipment. The impact of such facilities relative to power system reliability has not yet been quantified. Area entities are also taking steps to install and interface with equipment that may morph into full-fledged smart grid installations. The pace and extent of such changes is presently unknown. The CISO's website presents its smart grid initiatives, which are typical of activities within the assessment area.[294]

WECC's in-house power system disturbance investigations have identified relay protection misoperation as a factor in reduced system reliability. On June 22, 2011, WECC's Board of Directors approved PRC-003-WECC-CRT-1, Analysis, Reporting, and Mitigation of Transmission and Generation Protection Systems and Remedial Action Schemes Misoperations Procedure.[295] The procedure was developed to meet NERC Reliability Standard PRC-003-1, R1. It is expected that the mandatory compliance criteria will lead to a reduction in the adverse reliability effects related to relay protection misoperations.

WECC has not assessed the possible interconnection-wide effects of pending future environmental regulations. Several coal-fired plants have significant exposure to emissions limitations, and some have been or are scheduled to be shut down during the assessment period, while others are in discussion or litigation regarding emissions issues. In addition, several California power plants are subject to once-through cooling (OTC) limitations that may result in plant closures. The resource data used for this assessment reflect some capacity retirements due to existing clean air and once-through cooling initiatives but do not reflect possible retirements due to potential environmental regulations. California's OTC initiative includes provisions for stakeholder input regarding reliability issues associated with the plant shutdown scheduling, and it is expected that the initiative will be implemented on a schedule that will avoid any adverse reliability impact. It is not expected that long-term maintenance outages associated with coal-plant emissions equipment retrofits will affect reliability, and it is not expected that retrofit time schedules will lead to off-peak reliability issues. However, extended retrofit shutdowns coupled with unexpected, unseasonable severe weather could result in somewhat localized capacity issues.

Standing and Emerging Reliability Issues

The WECC LRS has identified four emerging reliability issues that may impact entity activities in the Western Interconnection. The Subcommittee has discussed the emerging issues in general terms but has not attempted to associate likelihood or consequences to the four issues, which vary by subregion. Since none of these issues have currently identified time frames associated with specific adverse consequences that cannot be mitigated in a reasonable manner, an impact on adverse reliability resource adequacy is not expected to occur. Due to the fluid nature of entity responses to these issues, the timing and locations of potential impact, if any, on transmission adequacy during the assessment period cannot be ascertained with a high level of certainty.

Impact of Federal and State Environmental Regulations

WECC contains a significant number of coal-fired power plants that may be affected by new emissions regulations. The overall impact of environmental regulations has not been studied by the subcommittee, but some information regarding

[294] California ISO - Smart Grid: http://www.caiso.com/green/greensmartgrid.html.

[295] WECC Relay Misoperation Criterion: http://www.wecc.biz/Standards/Development/WECC-0059/Shared%20Documents/Final%20to%20SC%20for%20Concurrent%20Posting/WECC-0059%20Relay%20Misoperation%20Criterion%20Effective%2010-1-2011.pdf.

the issue is available in the "Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations" section of the *2011 LTRA*[296]

In August 2011, the Canadian federal government published draft regulations that would require existing and new coal-fired units to reach CO_2 emissions levels equivalent to natural gas-fired combined-cycle plants. For existing plants the requirements would come into force once a plant reached the end of its useful life (approx. 45 years), and any new unit built after 2015 would need to reach the set emissions levels by 2025.

The two Canadian provinces within WECC, Alberta and British Columbia, will be impacted differently by this regulation. British Columbia has no coal-fired generation and will not be affected, as it has no plans to build new coal-fired facilities. However, this regulation will affect the retirement of existing units in Alberta as well as the addition of coal-fired capacity. In Alberta, about 1,000 MW of existing coal-fired capacity will reach the end of its useful life by 2020. The majority of this capacity is expected to retire, as retrofitting to meet the required emissions levels is currently prohibitively expensive. The Alberta market, however, is expected to manage the development of new generation to replace retired capacity over the next decade, and resource adequacy is not expected to be significantly reduced.

The WECC-Mexico subregion does not contain coal-fired power plants.

California State Water Resources Control Board policy on OTC mitigation is intended to cause a substantial amount of California capacity to retire or be re-fitted to reduce environmental impact. Mechanisms are built into the OTC policy to consider any reliability concerns of California state energy agencies or the CISO. The principal issues are associated with local reliability concerns that are not addressed in this WECC-wide assessment. In southern California, the air quality mandates imposed on the South Coast Air Quality Management District by the federal Clean Air Act continue to place constraints on new power plant development, and possibly on repowering of existing OTC facilities. The state energy agencies and CISO are assisting the California Air Resources Board to assess minimum capacity requirements of southern California and the need for offsets to facilitate permitting of these capacity additions. Such capacity additions are closely related to OTC policy-induced repowering or retirement of older OTC facilities. In summary, state environmental impact reduction policies are being implemented with an awareness of reliability concerns, and all of the appropriate entities are collaborating to conduct planning assessments aspiring to simultaneously achieve these goals.

Integration of Variable Resources

The WECC LRS discussed light load period minimum generation conflicts between northwest wind and hydro generation. The unique northwest condition, which was essentially an economic issue rather than a reliability issue, could occur in other WECC subregions if their wind resource penetration increases to a presently unidentified extent. Solar penetration is less problematic relative to low nighttime and weekend load issues and is not expected to be a concern within a foreseeable time period.

Delays in Transmission Siting

Transmission siting delay issues can relate to both new transmission lines and to reconstructions and/or upgrades to existing lines, and both may be driven by either demand growth or by generation delivery needs. Regardless, siting delays may have reliability implications that need to be addressed by the appropriate transmission planners and their associated governmental authorities. The "not in my back yard" philosophy coupled with firmly entrenched environmental study requirements essentially guarantees transmission development time frames that extend beyond those most desirable to developers and are expected to recur through the LTRA time frame. While siting delays may ultimately adversely impact resource development, evolving conditions relative to smart grid enhancements may significantly transform WECC's stability-limited transmission system. Additional transforming events may include ongoing building of new gas-fired generation closer to load centers and increased rooftop solar power generation.

[296] Resource Adequacy Impacts of Potential U.S. Environmental Regulations: http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf.

WECC Subregional Tables

Planning Reserve Margins – WECC-AESO

WECC-AESO-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		19.18%	19.59%	21.38%	28.39%	21.77%	17.80%	12.43%	8.95%	6.07%	8.50%
PROSPECTIVE		19.18%	19.59%	21.38%	28.39%	21.77%	17.80%	12.43%	8.95%	6.07%	8.50%
ADJUSTED POTENTIAL		19.18%	19.59%	21.38%	28.39%	21.77%	17.80%	12.43%	8.95%	6.07%	8.50%
NERC REFERENCE	-	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**

WECC-AESO-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		18.58%	28.97%	37.24%	34.83%	35.36%	25.99%	22.91%	23.64%	15.47%	13.32%
PROSPECTIVE		18.58%	28.97%	37.24%	34.83%	35.36%	25.99%	22.91%	23.64%	15.47%	13.32%
ADJUSTED POTENTIAL		18.58%	28.97%	37.24%	34.83%	35.36%	25.99%	22.91%	23.64%	15.47%	13.32%
NERC REFERENCE	-	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**

Planning Reserve Margins – WECC-BASN

WECC-BASN-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		27.53%	22.14%	19.81%	18.08%	15.30%	13.35%	10.44%	7.46%	6.59%	7.17%
PROSPECTIVE		27.53%	22.14%	19.81%	18.08%	15.30%	13.35%	10.44%	7.46%	6.59%	7.17%
ADJUSTED POTENTIAL		27.53%	25.57%	23.15%	23.72%	20.82%	18.78%	15.80%	14.07%	13.10%	13.96%
NERC REFERENCE	-	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**

WECC-BASN-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		26.91%	23.82%	22.78%	15.67%	14.79%	17.58%	16.71%	16.15%	11.57%	11.96%
PROSPECTIVE		26.91%	23.82%	22.78%	15.67%	14.79%	17.58%	16.71%	16.15%	11.57%	11.96%
ADJUSTED POTENTIAL		26.91%	27.91%	27.07%	22.48%	21.47%	24.20%	24.94%	25.79%	21.67%	20.10%
NERC REFERENCE	-	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**

Planning Reserve Margins – WECC-BC

WECC-BC-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		41.74%	40.70%	35.36%	33.62%	31.81%	36.03%	33.16%	23.33%	14.97%	13.91%
PROSPECTIVE		41.74%	40.70%	35.36%	33.62%	31.81%	36.03%	33.16%	23.33%	14.97%	13.91%
ADJUSTED POTENTIAL		41.74%	40.70%	35.36%	33.62%	31.81%	36.03%	33.16%	23.33%	14.97%	13.91%
NERC REFERENCE	-	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**

WECC-BC-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		17.24%	18.15%	19.90%	20.05%	19.44%	17.88%	16.98%	14.43%	13.64%	12.82%
PROSPECTIVE		17.24%	18.15%	19.90%	20.05%	19.44%	17.88%	16.98%	14.43%	13.64%	12.82%
ADJUSTED POTENTIAL		17.24%	18.15%	19.90%	20.05%	19.44%	17.88%	16.98%	14.43%	13.64%	12.82%
NERC REFERENCE	-	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**

Planning Reserve Margins – WECC-CALN

WECC-CALN-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		15.16%	14.82%	18.29%	16.01%	14.71%	13.53%	9.06%	9.49%	9.22%	7.90%
PROSPECTIVE		15.16%	14.82%	18.29%	16.01%	14.71%	13.53%	9.06%	9.49%	9.22%	7.90%
ADJUSTED POTENTIAL		15.16%	14.82%	18.29%	16.02%	14.72%	13.54%	9.07%	9.49%	9.22%	7.91%
NERC REFERENCE	-	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**

WECC-CALN-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		22.55%	30.81%	28.82%	21.49%	24.46%	23.91%	23.18%	20.34%	18.82%	15.38%
PROSPECTIVE		22.55%	30.81%	28.82%	21.49%	24.46%	23.91%	23.18%	20.34%	18.82%	15.38%
ADJUSTED POTENTIAL		22.55%	30.81%	28.82%	21.50%	24.47%	24.91%	24.17%	21.32%	19.31%	16.23%
NERC REFERENCE	-	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**

Planning Reserve Margins – WECC-CALS

WECC-CALS-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		16.04%	20.94%	19.07%	18.63%	17.74%	15.22%	15.22%	15.44%	15.19%	15.31%
PROSPECTIVE		16.04%	20.94%	19.07%	18.63%	17.74%	15.22%	15.22%	15.44%	15.19%	15.31%
ADJUSTED POTENTIAL		16.29%	21.19%	19.31%	19.21%	18.40%	16.19%	16.22%	16.74%	16.48%	16.59%
NERC REFERENCE	-	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**

WECC-CALS-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		54.57%	49.51%	46.42%	39.95%	38.76%	40.21%	31.60%	21.18%	27.20%	20.62%
PROSPECTIVE		54.57%	49.51%	46.42%	39.95%	38.76%	40.21%	31.60%	21.18%	27.20%	20.62%
ADJUSTED POTENTIAL		54.90%	49.83%	46.74%	40.71%	39.64%	41.49%	32.87%	22.84%	28.84%	22.25%
NERC REFERENCE	-	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**

Planning Reserve Margins – WECC-DSW

WECC-DSW-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		46.57%	43.51%	45.69%	47.93%	47.03%	46.07%	41.56%	34.72%	29.52%	29.09%
PROSPECTIVE		46.57%	43.51%	45.69%	47.93%	47.03%	46.07%	41.56%	34.72%	29.52%	29.09%
ADJUSTED POTENTIAL		47.24%	45.13%	47.75%	50.17%	50.05%	48.86%	45.71%	39.93%	34.90%	34.40%
NERC REFERENCE	-	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**

WECC-DSW-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		91.01%	90.09%	89.45%	86.95%	83.98%	82.77%	76.41%	79.46%	78.49%	77.75%

PROSPECTIVE		91.01%	90.09%	89.45%	86.95%	83.98%	82.77%	76.41%	79.46%	78.49%	77.75%
ADJUSTED POTENTIAL		91.95%	91.04%	89.57%	89.16%	87.25%	85.98%	83.57%	88.27%	82.91%	83.72%
NERC REFERENCE	-	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**

Planning Reserve Margins – WECC-MEXW

WECC-MEXW-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		19.89%	29.35%	26.17%	23.16%	20.27%	17.50%	14.86%	12.35%	9.94%	7.65%
PROSPECTIVE		19.89%	29.35%	26.17%	23.16%	20.27%	17.50%	14.86%	12.35%	9.94%	7.65%
ADJUSTED POTENTIAL		19.89%	29.35%	26.17%	37.50%	34.27%	31.18%	38.90%	35.85%	32.94%	30.17%
NERC REFERENCE	-	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**

WECC-MEXW-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		62.92%	70.84%	75.07%	80.27%	76.03%	57.02%	60.83%	57.05%	53.67%	50.59%
PROSPECTIVE		62.92%	70.84%	75.07%	80.27%	76.03%	57.02%	60.83%	57.05%	53.67%	50.59%
ADJUSTED POTENTIAL		62.92%	70.84%	75.07%	101.41%	96.69%	77.20%	96.29%	91.72%	87.59%	83.81%
NERC REFERENCE	-	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**

Planning Reserve Margins – WECC-NORW

WECC-NORW-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		18.96%	18.02%	19.06%	22.91%	19.86%	18.14%	18.14%	18.14%	18.13%	18.51%
PROSPECTIVE		18.96%	18.02%	19.06%	22.91%	19.86%	18.14%	18.14%	18.14%	18.13%	18.51%
ADJUSTED POTENTIAL		18.96%	18.02%	19.06%	22.91%	19.87%	18.14%	18.15%	18.14%	18.14%	18.51%
NERC REFERENCE	-	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**

WECC-NORW-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		20.08%	20.24%	20.80%	22.98%	20.35%	21.31%	18.80%	17.30%	15.67%	22.18%
PROSPECTIVE		20.08%	20.24%	20.80%	22.98%	20.35%	21.31%	18.80%	17.30%	15.67%	22.18%
ADJUSTED POTENTIAL		20.08%	20.25%	20.80%	22.98%	20.35%	21.31%	18.80%	17.31%	15.68%	22.18%
NERC REFERENCE	-	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**

Planning Reserve Margins – WECC-ROCK

WECC-ROCK-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		24.93%	21.91%	19.77%	18.04%	15.20%	13.38%	12.84%	15.56%	11.94%	8.02%
PROSPECTIVE		24.93%	21.91%	19.77%	18.04%	15.20%	13.38%	12.84%	15.56%	11.94%	8.02%
ADJUSTED POTENTIAL		24.96%	21.93%	19.83%	18.07%	15.24%	13.49%	12.97%	15.59%	11.97%	8.03%
NERC REFERENCE	-	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**

WECC-ROCK-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		46.61%	37.17%	33.54%	41.22%	43.12%	37.50%	35.35%	20.45%	26.85%	19.14%
PROSPECTIVE		46.61%	37.17%	33.54%	41.22%	43.12%	37.50%	35.35%	20.45%	26.85%	19.14%
ADJUSTED POTENTIAL		49.08%	40.39%	37.50%	43.00%	45.80%	42.18%	40.23%	24.35%	30.64%	19.27%
NERC REFERENCE	-	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**

Demand Outlook – WECC-AESO

WECC-AESO-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	10,903	15,093	4,190	38.4%	3.68%
Load-Modifying Demand Response	38	38	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**10,941**	**15,131**	**4,190**	**38.3%**	**3.67%**

WECC-AESO-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	11,664	15,994	4,330	37.1%	3.57%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**11,664**	**15,994**	**4,330**	**37.1%**	**3.57%**

Demand Outlook – WECC-BASN

WECC-BASN-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	12,667	14,756	2,089	16.5%	1.71%
Load-Modifying Demand Response	1,109	1,158	49	4.4%	0.48%
TOTAL INTERNAL DEMAND	**13,776**	**15,914**	**2,138**	**15.5%**	**1.62%**

WECC-BASN-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	10,842	12,132	1,290	11.9%	1.26%
Load-Modifying Demand Response	292	305	13	4.5%	0.49%
TOTAL INTERNAL DEMAND	**11,134**	**12,437**	**1,303**	**11.7%**	**1.24%**

Demand Outlook – WECC-BC

WECC-BC-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	8,449	9,670	1,221	14.5%	1.51%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**8,449**	**9,670**	**1,221**	**14.5%**	**1.51%**

WECC-BC-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	11,416	12,823	1,407	12.3%	1.30%

Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**11,416**	**12,823**	**1,407**	**12.3%**	**1.30%**

Demand Outlook – WECC-CALN

WECC-CALN-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	25,841	29,077	3,236	12.5%	1.32%
Load-Modifying Demand Response	804	835	31	3.9%	0.42%
TOTAL INTERNAL DEMAND	**26,645**	**29,912**	**3,267**	**12.3%**	**1.29%**

WECC-CALN-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	18,407	20,220	1,813	9.9%	1.05%
Load-Modifying Demand Response	257	278	21	8.2%	0.88%
TOTAL INTERNAL DEMAND	**18,664**	**20,498**	**1,834**	**9.8%**	**1.05%**

Demand Outlook – WECC-CALS

WECC-CALS-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	29,311	33,319	4,008	13.7%	1.43%
Load-Modifying Demand Response	2,008	2,296	288	14.3%	1.50%
TOTAL INTERNAL DEMAND	**31,319**	**35,615**	**4,296**	**13.7%**	**1.44%**

WECC-CALS-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	22,360	25,454	3,094	13.8%	1.45%
Load-Modifying Demand Response	869	1,153	284	32.7%	3.19%
TOTAL INTERNAL DEMAND	**23,229**	**26,607**	**3,378**	**14.5%**	**1.52%**

Demand Outlook – WECC-DSW

WECC-DSW-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	27,034	31,013	3,979	14.7%	1.54%
Load-Modifying Demand Response	542	589	47	8.7%	0.93%
TOTAL INTERNAL DEMAND	**27,576**	**31,602**	**4,026**	**14.6%**	**1.53%**

WECC-DSW-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	17,845	20,775	2,930	16.4%	1.70%
Load-Modifying Demand Response	279	290	11	3.9%	0.43%
TOTAL INTERNAL DEMAND	**18,124**	**21,065**	**2,941**	**16.2%**	**1.69%**

Demand Outlook – WECC-MEXW

WECC-MEXW-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	2,203	2,716	513	23.3%	2.35%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**2,203**	**2,716**	**513**	**23.3%**	**2.35%**

WECC-MEXW-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	1,494	1,841	347	23.2%	2.35%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**1,494**	**1,841**	**347**	**23.2%**	**2.35%**

Demand Outlook – WECC-NORW

WECC-NORW-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	24,310	26,711	2,401	9.9%	1.05%
Load-Modifying Demand Response	70	147	77	110.0%	8.59%
TOTAL INTERNAL DEMAND	**24,380**	**26,858**	**2,478**	**10.2%**	**1.08%**

WECC-NORW-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	30,217	32,638	2,420	8.0%	0.86%
Load-Modifying Demand Response	53	121	68	128.3%	9.61%
TOTAL INTERNAL DEMAND	**30,270**	**32,759**	**2,488**	**8.2%**	**0.88%**

Demand Outlook – WECC-ROCK

WECC-ROCK-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	11,434	13,251	1,817	15.9%	1.65%
Load-Modifying Demand Response	470	520	50	10.6%	1.13%
TOTAL INTERNAL DEMAND	**11,904**	**13,771**	**1,867**	**15.7%**	**1.63%**

WECC-ROCK-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	9,565	11,283	1,718	18.0%	1.85%
Load-Modifying Demand Response	268	238	-30	-11.2%	-1.31%
TOTAL INTERNAL DEMAND	**9,833**	**11,521**	**1,688**	**17.2%**	**1.78%**

Net Transactions – WECC-AESO

WECC-AESO	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	0	0	0	0	0	0	0	0	0	0

TOTAL IMPORTS	0	0	0	0	0	0	0	0	0	0
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	600	600	600	600	600	600	600	600	600	600
TOTAL EXPORTS	600	600	600	600	600	600	600	600	600	600
TOTAL NET CAPACITY TRANSACTIONS	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**

Net Transactions – WECC-BASN

WECC-BASN	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313
TOTAL IMPORTS	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760
TOTAL EXPORTS	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760
TOTAL NET CAPACITY TRANSACTIONS	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**

Net Transactions – WECC-BC

WECC-BC	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	600	600	600	600	600	600	600	600	600	600
TOTAL IMPORTS	600	600	600	600	600	600	600	600	600	600
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	800	800	800	800	800	800	800	800	800	800
TOTAL EXPORTS	800	800	800	800	800	800	800	800	800	800
TOTAL NET CAPACITY TRANSACTIONS	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**

Net Transactions – WECC-CALN

WECC-CALN	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	4,200	4,100	4,200	4,200	4,200	4,200	3,400	3,900	4,200	4,200
TOTAL IMPORTS	4,200	4,100	4,200	4,200	4,200	4,200	3,400	3,900	4,200	4,200
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	100	100	100	100	100	100	100	100	100	100
TOTAL EXPORTS	100	100	100	100	100	100	100	100	100	100
TOTAL NET CAPACITY TRANSACTIONS	**4,100**	**4,000**	**4,100**	**4,100**	**4,100**	**4,100**	**3,300**	**3,800**	**4,100**	**4,100**

Net Transactions – WECC-CALS

WECC-CALS	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	6,931	7,481	6,977	6,862	6,879	6,862	6,862	6,862	6,862	6,862
TOTAL IMPORTS	6,931	7,481	6,977	6,862	6,879	6,862	6,862	6,862	6,862	6,862
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	3,529	3,564	3,782	4,783	4,783	5,181	4,677	4,043	3,588	3,206
TOTAL EXPORTS	3,529	3,564	3,782	4,783	4,783	5,181	4,677	4,043	3,588	3,206
TOTAL NET CAPACITY TRANSACTIONS	**3,402**	**3,917**	**3,195**	**2,079**	**2,096**	**1,681**	**2,185**	**2,819**	**3,274**	**3,656**

Net Transactions – WECC-DSW

WECC-DSW	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	2,271	2,306	2,524	3,539	3,051	3,937	3,432	2,902	2,323	2,065
TOTAL IMPORTS	2,271	2,306	2,524	3,539	3,051	3,937	3,432	2,902	2,323	2,065
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	4,023	4,806	4,068	3,953	3,953	3,953	3,953	4,617	4,380	3,953
TOTAL EXPORTS	4,023	4,806	4,068	3,953	3,953	3,953	3,953	4,617	4,380	3,953
TOTAL NET CAPACITY TRANSACTIONS	**-1,752**	**-2,500**	**-1,544**	**-414**	**-902**	**-16**	**-521**	**-1,715**	**-2,057**	**-1,888**

Net Transactions – WECC-MEXW

WECC-MEXW	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	0	0	0	0	0	0	0	0	0	0
TOTAL IMPORTS	0	0	0	0	0	0	0	0	0	0
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Net Transactions – WECC-NORW

WECC-NORW	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	4,100	4,000	4,000	4,000	4,500	4,000	5,400	5,400	5,400	4,000
TOTAL IMPORTS	4,100	4,000	4,000	4,000	4,500	4,000	5,400	5,400	5,400	4,000
Expected Exports	0	0	0	0	0	0	0	0	0	0

Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**4,100**	**4,000**	**4,000**	**4,000**	**4,500**	**4,000**	**5,400**	**5,400**	**5,400**	**4,000**

Net Transactions – WECC-ROCK

WECC-ROCK	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	400	634	400	400	400	400	400	1,064	827	400
TOTAL IMPORTS	400	634	400	400	400	400	400	1,064	827	400
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	274	531	531	531	531	531	531	531	531	531
TOTAL EXPORTS	274	531	531	531	531	531	531	531	531	531
TOTAL NET CAPACITY TRANSACTIONS	**126**	**103**	**-131**	**-131**	**-131**	**-131**	**-131**	**533**	**296**	**-131**

Appendix I: NERC Reference Case –Annual Demand Tables

Annual Net Internal Demand - Summer

Assessment Area/Country	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Change		CAGR
ERCOT	65,649	68,403	71,692	73,957	75,360	76,483	76,769	78,524	79,682	80,694	15,045	22.92%	2.32%
FRCC	43,041	43,618	44,459	45,242	45,802	46,152	46,803	47,581	48,273	48,923	5,882	13.67%	1.43%
MISO	89,318	90,707	91,096	91,556	92,022	92,447	92,932	93,419	93,957	94,875	5,557	6.22%	0.67%
MRO-MAPP	4,904	5,024	5,135	5,406	5,461	5,543	5,643	5,735	5,821	5,906	1,002	20.44%	2.09%
NPCC-New England	26,629	26,877	27,193	27,520	27,797	27,973	28,111	28,257	28,414	28,583	1,954	7.34%	0.79%
NPCC-New York	33,696	33,914	34,151	34,345	34,550	34,868	35,204	35,526	35,913	36,230	2,534	7.52%	0.81%
PJM	145,254	146,642	149,968	152,491	154,233	155,832	157,660	159,593	161,438	163,220	17,966	12.37%	1.30%
SERC-E	41,805	42,412	42,750	43,235	43,707	44,103	44,636	45,200	45,848	46,386	4,581	10.96%	1.16%
SERC-N	43,808	44,387	44,952	45,537	45,987	46,504	47,044	47,653	48,167	48,778	4,970	11.35%	1.20%
SERC-SE	47,900	48,738	49,227	49,823	50,551	51,023	51,707	52,396	53,343	54,249	6,349	13.25%	1.39%
SERC-W	25,015	25,257	25,623	25,937	26,252	26,556	26,910	27,198	27,472	27,764	2,749	10.99%	1.17%
SPP	54,247	54,794	54,788	55,368	55,927	56,539	57,338	57,971	58,716	58,985	4,738	8.73%	0.93%
WECC-BASN	12,667	13,025	13,354	13,607	13,923	14,148	14,392	14,628	14,836	14,756	2,089	16.49%	1.71%
WECC-CALN	25,841	26,154	26,471	27,072	27,376	27,670	27,998	28,324	28,652	29,077	3,236	12.52%	1.32%
WECC-CALS	29,311	29,901	30,467	30,796	31,191	31,577	31,948	32,472	32,997	33,319	4,008	13.67%	1.43%
WECC-DSW	27,034	27,252	27,551	28,035	28,510	29,106	29,622	30,183	30,720	31,013	3,979	14.72%	1.54%
WECC-NORW	24,310	24,609	24,872	25,155	25,445	25,675	25,901	26,151	26,414	26,711	2,401	9.88%	1.05%
WECC-ROCK	11,434	11,619	11,827	12,048	12,235	12,431	12,626	12,840	13,093	13,251	1,817	15.89%	1.65%
TOTAL-UNITED STATES	751,862	763,332	775,577	787,129	796,328	804,630	813,244	823,652	833,758	842,721	90,859	12.08%	1.28%
MRO-Manitoba Hydro	3,210	3,238	3,207	3,244	3,286	3,221	3,271	3,348	3,428	3,474	264	8.24%	0.88%
MRO-SaskPower	3,184	3,335	3,444	3,533	3,630	3,618	3,665	3,716	3,784	3,847	663	20.81%	2.12%
NPCC-Maritimes	3,104	3,138	3,117	3,110	3,116	3,128	3,140	3,163	3,175	3,183	79	2.55%	0.28%
NPCC-Ontario	23,301	23,080	22,859	22,638	22,471	22,583	22,891	23,010	23,390	23,442	142	0.61%	0.07%
NPCC-Québec	21,115	21,550	21,642	21,883	22,008	22,125	22,307	22,503	22,662	22,818	1,704	8.07%	0.87%
WECC-AESO	10,903	11,510	12,039	12,604	13,108	13,522	13,936	14,336	14,727	15,093	4,190	38.43%	3.68%
WECC-BC	8,449	8,684	8,834	8,913	9,043	9,167	9,289	9,427	9,553	9,670	1,221	14.45%	1.51%
TOTAL-CANADA	73,266	74,535	75,142	75,925	76,663	77,364	78,498	79,504	80,719	81,528	8,262	11.28%	1.19%
WECC-MEXW	2,203	2,260	2,317	2,374	2,431	2,488	2,545	2,602	2,659	2,716	513	23.29%	2.35%
TOTAL-MÉXICO	2,203	2,260	2,317	2,374	2,431	2,488	2,545	2,602	2,659	2,716	513	23.29%	2.35%
TOTAL-NERC	**827,330**	**840,127**	**853,036**	**865,428**	**875,421**	**884,482**	**894,287**	**905,758**	**917,136**	**926,965**	**99,635**	**12.04%**	**1.27%**

Annual Net Internal Demand – Winter

Assessment Area/Country	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Change		CAGR
ERCOT	50,263	50,533	53,378	54,363	57,204	57,459	57,575	58,210	59,031	61,450	11,187	22.26%	2.26%
FRCC	43,049	44,228	44,790	45,297	45,752	46,305	46,910	47,509	48,169	48,656	5,607	13.02%	1.37%
MISO	69,663	74,965	75,354	75,854	76,172	76,692	77,174	77,498	78,022	78,789	9,126	13.10%	1.38%
MRO-MAPP	4,858	4,999	5,074	5,335	5,412	5,522	5,623	5,718	5,814	5,904	1,047	21.55%	2.19%
NPCC-New England	21,383	21,285	21,193	21,097	21,011	20,929	20,859	20,797	20,750	20,711	-672	-3.14%	-0.35%
NPCC-New York	24,929	24,999	25,053	25,149	25,153	25,265	25,422	25,627	25,794	25,908	979	3.93%	0.43%
PJM	121,160	121,571	123,711	125,367	126,462	127,644	128,818	130,219	131,636	132,916	11,756	9.70%	1.03%
SERC-E	42,042	42,408	42,934	43,395	43,879	44,382	45,016	45,557	46,144	46,730	4,688	11.15%	1.18%
SERC-N	43,734	44,212	44,685	45,226	45,723	46,176	46,697	47,211	47,891	48,256	4,522	10.34%	1.10%
SERC-SE	44,652	45,103	45,615	46,266	46,743	47,434	48,097	48,943	49,770	50,627	5,975	13.38%	1.41%
SERC-W	19,731	20,042	20,209	20,694	21,106	21,410	21,118	21,726	21,891	22,262	2,531	12.83%	1.35%
SPP	40,983	41,345	41,225	41,812	42,205	42,726	43,360	43,930	44,470	44,862	3,879	9.47%	1.01%
WECC-BASN	10,842	10,913	11,167	11,416	11,640	11,818	11,940	12,026	12,158	12,132	1,290	11.90%	1.26%
WECC-CALN	18,407	18,707	18,937	19,220	19,409	19,618	19,767	19,919	20,070	20,220	1,813	9.85%	1.05%
WECC-CALS	22,360	22,893	23,235	23,441	23,770	24,099	24,438	24,941	25,300	25,454	3,094	13.84%	1.45%
WECC-DSW	17,845	18,095	18,431	18,827	19,187	19,540	19,945	20,263	20,490	20,775	2,930	16.42%	1.70%
WECC-NORW	30,217	30,507	30,763	31,053	31,355	31,607	31,862	32,075	32,391	32,638	2,420	8.01%	0.86%
WECC-ROCK	9,565	9,709	9,918	10,214	10,398	10,602	10,796	10,922	11,165	11,283	1,718	17.96%	1.85%
TOTAL-UNITED STATES	635,683	646,514	655,672	664,025	672,581	679,228	685,417	693,092	700,956	709,572	73,889	11.62%	1.23%
MRO-Manitoba Hydro	4,661	4,712	4,723	4,781	4,845	4,801	4,878	4,981	5,089	5,162	501	10.76%	1.14%
MRO-SaskPower	3,580	3,738	3,859	3,959	4,068	4,054	4,107	4,164	4,239	4,310	730	20.39%	2.08%
NPCC-Maritimes	5,169	5,166	5,165	5,185	5,201	5,226	5,228	5,247	5,264	5,285	116	2.24%	0.25%
NPCC-Ontario	22,192	21,890	21,500	21,153	20,719	20,700	21,063	21,234	21,441	21,529	-663	-2.99%	-0.34%
NPCC-Québec	37,810	38,062	38,527	38,845	39,189	39,487	39,812	40,079	40,317	40,575	2,766	7.31%	0.79%
WECC-AESO	11,664	12,162	12,801	13,382	13,856	14,351	14,759	15,162	15,618	15,994	4,330	37.12%	3.57%
WECC-BC	11,416	11,738	11,943	12,050	12,073	12,223	12,373	12,523	12,673	12,823	1,407	12.32%	1.30%
TOTAL-CANADA	96,492	97,467	98,517	99,355	99,951	100,842	102,219	103,391	104,640	105,679	9,187	9.52%	1.02%
WECC-MEXW	1,494	1,532	1,571	1,610	1,648	1,687	1,725	1,764	1,803	1,841	347	23.23%	2.35%
TOTAL-MÉXICO	1,494	1,532	1,571	1,610	1,648	1,687	1,725	1,764	1,803	1,841	347	23.23%	2.35%
TOTAL-NERC	**733,669**	**745,513**	**755,760**	**764,990**	**774,180**	**781,757**	**789,361**	**798,246**	**807,399**	**817,092**	**83,423**	**11.37%**	**1.20%**

Annual Total Internal Demand – Summer

Assessment Area/Country	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Change		CAGR
ERCOT	66,928	69,721	73,054	75,366	76,821	78,002	78,351	80,176	81,410	82,507	15,579	23.28%	2.35%
FRCC	46,270	46,857	47,758	48,594	49,244	49,643	50,356	51,191	51,933	52,583	6,313	13.64%	1.43%
MISO	94,279	96,129	96,929	97,811	98,729	99,611	100,565	101,530	102,559	103,584	9,305	9.87%	1.05%
MRO-MAPP	4,995	5,117	5,230	5,503	5,560	5,643	5,746	5,840	5,928	6,015	1,020	20.42%	2.09%
NPCC-New England	27,765	28,275	28,840	29,400	29,895	30,275	30,605	30,930	31,255	31,583	3,818	13.75%	1.44%
NPCC-New York	33,696	33,914	34,151	34,345	34,550	34,868	35,204	35,526	35,913	36,230	2,534	7.52%	0.81%
PJM	156,254	159,842	163,168	165,691	167,433	169,032	170,860	172,793	174,638	176,420	20,166	12.91%	1.36%
SERC-E	43,733	44,457	44,903	45,436	45,939	46,358	46,908	47,487	48,149	48,697	4,964	11.35%	1.20%
SERC-N	45,750	46,542	47,303	47,974	48,660	49,288	50,090	50,868	51,345	52,038	6,288	13.74%	1.44%
SERC-SE	49,799	50,838	51,431	52,045	52,789	53,256	53,948	54,645	55,600	56,512	6,713	13.48%	1.42%
SERC-W	25,921	26,166	26,563	26,881	27,199	27,505	27,863	28,153	28,435	28,730	2,809	10.84%	1.15%
SPP	55,180	55,732	55,766	56,364	57,055	57,591	58,378	59,239	59,904	60,088	4,908	8.90%	0.95%
WECC-BASN	13,776	14,144	14,482	14,765	15,081	15,306	15,550	15,786	15,994	15,914	2,138	15.52%	1.62%
WECC-CALN	26,645	26,971	27,298	27,904	28,211	28,507	28,834	29,160	29,487	29,912	3,267	12.26%	1.29%
WECC-CALS	31,319	31,896	32,472	32,821	33,254	33,666	34,090	34,666	35,243	35,615	4,296	13.72%	1.44%
WECC-DSW	27,576	27,847	28,179	28,679	29,157	29,686	30,204	30,764	31,305	31,602	4,026	14.60%	1.53%
WECC-NORW	24,380	24,694	24,967	25,270	25,560	25,797	26,034	26,295	26,561	26,858	2,478	10.16%	1.08%
WECC-ROCK	11,904	12,107	12,330	12,563	12,763	12,970	13,176	13,404	13,615	13,771	1,867	15.68%	1.63%
TOTAL-UNITED STATES	786,170	801,249	814,823	827,411	837,899	847,005	856,761	868,453	879,275	888,660	102,490	13.04%	1.37%
MRO-Manitoba Hydro	3,210	3,238	3,207	3,244	3,286	3,221	3,271	3,348	3,428	3,474	264	8.24%	0.88%
MRO-SaskPower	3,275	3,426	3,535	3,624	3,721	3,709	3,756	3,807	3,875	3,938	663	20.24%	2.07%
NPCC-Maritimes	3,435	3,469	3,448	3,441	3,447	3,459	3,471	3,494	3,506	3,514	79	2.30%	0.25%
NPCC-Ontario	23,301	23,080	22,859	22,638	22,471	22,583	22,891	23,010	23,390	23,442	142	0.61%	0.07%
NPCC-Québec	21,115	21,550	21,642	21,883	22,008	22,125	22,307	22,503	22,662	22,818	1,704	8.07%	0.87%
WECC-AESO	10,941	11,548	12,077	12,642	13,146	13,560	13,974	14,374	14,765	15,131	4,190	38.30%	3.67%
WECC-BC	8,449	8,684	8,834	8,913	9,043	9,167	9,289	9,427	9,553	9,670	1,221	14.45%	1.51%
TOTAL-CANADA	73,726	74,995	75,602	76,385	77,123	77,824	78,958	79,964	81,179	81,988	8,262	11.21%	1.19%
WECC-MEXW	2,203	2,260	2,317	2,374	2,431	2,488	2,545	2,602	2,659	2,716	513	23.29%	2.35%
TOTAL-MÉXICO	2,203	2,260	2,317	2,374	2,431	2,488	2,545	2,602	2,659	2,716	513	23.29%	2.35%
TOTAL-NERC	**862,098**	**878,504**	**892,742**	**906,170**	**917,453**	**927,317**	**938,265**	**951,019**	**963,113**	**973,364**	**111,266**	**12.91%**	**1.36%**

Annual Total Internal Demand – Winter

Assessment Area/Country	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Change		CAGR
ERCOT	51,734	52,063	54,972	56,028	58,869	59,202	59,318	60,039	60,917	63,336	11,602	22.43%	2.27%
FRCC	46,367	47,568	48,172	48,797	49,298	49,908	50,570	51,218	51,921	52,408	6,041	13.03%	1.37%
MISO	72,572	78,143	78,773	79,521	80,104	80,891	81,649	82,252	83,064	83,894	11,322	15.60%	1.62%
MRO-MAPP	4,858	4,999	5,074	5,335	5,412	5,522	5,623	5,718	5,814	5,904	1,047	21.55%	2.19%
NPCC-New England	22,510	22,670	22,825	22,960	23,090	23,210	23,330	23,445	23,565	23,686	1,176	5.22%	0.57%
NPCC-New York	24,929	24,999	25,053	25,149	25,153	25,265	25,422	25,627	25,794	25,908	979	3.93%	0.43%
PJM	132,160	134,771	136,911	138,567	139,662	140,844	142,018	143,419	144,836	146,116	13,956	10.56%	1.12%
SERC-E	43,582	43,977	44,520	44,993	45,487	46,003	46,648	47,201	47,797	48,395	4,813	11.04%	1.17%
SERC-N	45,713	46,433	47,166	47,967	48,659	49,266	49,932	50,584	51,397	51,914	6,201	13.56%	1.42%
SERC-SE	46,534	47,197	47,814	48,485	48,978	49,665	50,338	51,193	52,029	52,894	6,360	13.67%	1.43%
SERC-W	20,497	20,835	20,992	21,493	21,908	22,215	21,923	22,539	22,707	23,082	2,585	12.61%	1.33%
SPP	41,714	42,010	42,040	42,644	43,069	43,590	44,223	44,794	45,334	45,726	4,012	9.62%	1.03%
WECC-BASN	11,134	11,215	11,472	11,721	11,945	12,123	12,245	12,331	12,463	12,437	1,303	11.70%	1.24%
WECC-CALN	18,664	18,977	19,212	19,498	19,689	19,898	20,048	20,198	20,348	20,498	1,834	9.83%	1.05%
WECC-CALS	23,229	23,753	24,106	24,332	24,697	25,051	25,440	25,994	26,403	26,607	3,378	14.54%	1.52%
WECC-DSW	18,124	18,380	18,721	19,117	19,477	19,830	20,235	20,553	20,780	21,065	2,941	16.23%	1.69%
WECC-NORW	30,270	30,577	30,843	31,148	31,450	31,705	31,971	32,195	32,512	32,759	2,488	8.22%	0.88%
WECC-ROCK	9,833	9,978	10,189	10,486	10,672	10,877	11,072	11,200	11,401	11,521	1,688	17.17%	1.78%
TOTAL-UNITED STATES	664,424	678,545	688,855	698,239	707,619	715,065	722,005	730,501	739,081	748,149	83,725	12.60%	1.33%
MRO-Manitoba Hydro	4,661	4,712	4,723	4,781	4,845	4,801	4,878	4,981	5,089	5,162	501	10.76%	1.14%
MRO-SaskPower	3,671	3,829	3,950	4,050	4,159	4,145	4,198	4,255	4,330	4,401	730	19.89%	2.04%
NPCC-Maritimes	5,421	5,420	5,419	5,444	5,462	5,489	5,492	5,513	5,530	5,552	131	2.42%	0.27%
NPCC-Ontario	22,192	21,890	21,500	21,153	20,719	20,700	21,063	21,234	21,441	21,529	-663	-2.99%	-0.34%
NPCC-Québec	37,810	38,062	38,527	38,845	39,189	39,487	39,812	40,079	40,317	40,575	2,766	7.31%	0.79%
WECC-AESO	11,664	12,162	12,801	13,382	13,856	14,351	14,759	15,162	15,618	15,994	4,330	37.12%	3.57%
WECC-BC	11,416	11,738	11,943	12,050	12,073	12,223	12,373	12,523	12,673	12,823	1,407	12.32%	1.30%
TOTAL-CANADA	96,835	97,812	98,863	99,706	100,303	101,196	102,575	103,747	104,997	106,037	9,202	9.50%	1.01%
WECC-MEXW	1,494	1,532	1,571	1,610	1,648	1,687	1,725	1,764	1,803	1,841	347	23.23%	2.35%
TOTAL-MÉXICO	1,494	1,532	1,571	1,610	1,648	1,687	1,725	1,764	1,803	1,841	347	23.23%	2.35%
TOTAL-NERC	**762,753**	**777,889**	**789,289**	**799,555**	**809,570**	**817,948**	**826,305**	**836,012**	**845,882**	**856,027**	**93,274**	**12.23%**	**1.29%**

Appendix II: NERC-Wide Transmission Additions, Upgrades, and Retirements

Table Notes

- Includes 100 kV and above transmission additions, upgrades, and retirements with in-service dates from 2012-2022, as reported by each NERC Assessment Area.
- Line length in circuit miles is presented in terms of net change; relining, rerating and other upgrades typically result in no change in line length, while retired lines result in negative circuit miles (unless otherwise noted).
- Project status categories are defined below:
    - UC: Project Under Construction
    - P: New Planned Project
    - U: Planned Upgrade of Existing Line
    - C: New Conceptual Project
    - R: Retirement of Existing Line

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
ERCOT	00TPIT0004	C	DeCordova	Benbrook	27.0	300-399	AC	Unknown	2018
ERCOT	00TPITno07	C	Loma Alta Substation	Rio Hondo Substation	35.0	300-399	AC	Unknown	2018
ERCOT	05TPIT0065	P	Highway 32	Wimberley	4.0	121-150	AC	Unknown	2014
ERCOT	06TPIT0036	C	Ennis Switch	Ennis	6.3	121-150	AC	Unknown	2018
ERCOT	06TPIT0042	C	Lake Wichita Switch	Wichitia Falls Switch	6.3	121-150	AC	Unknown	2018
ERCOT	06TPIT0043	C	Sherry	Liggett	13.0	121-150	AC	Unknown	2014
ERCOT	06TPIT0047	C	Elkton	Tyler	5.0	121-150	AC	Unknown	2018
ERCOT	06TPIT0068	C	Hamilton Road	Picacho	8.7	121-150	AC	Unknown	2018
ERCOT	06TPIT0082	C	Buena Vista	Picacho	3.0	121-150	AC	Unknown	2018
ERCOT	06TPIT0083	C	Del Rio	Buena Vista	3.0	121-150	AC	Unknown	2018
ERCOT	06TPIT0084	C	Hamilton Road	Del Rio	3.0	121-150	AC	Unknown	2018
ERCOT	06TPIT0112	P	Lakeway Substation	Lakeway Substation	0.9	121-150	AC	Unknown	2012
ERCOT	06TPIT0143	C	Temple Switch	Temple SE	4.4	121-150	AC	Unknown	2014
ERCOT	07TPIT0001	C	Liggett	Trinity Switch	12.8	300-399	AC	Unknown	2018
ERCOT	07TPIT0012	C	Trinity Switch	Richland	0.5	121-150	AC	Unknown	2018
ERCOT	07TPIT0014	C	Plano West	Richardson Tap	1.9	121-150	AC	Unknown	2020
ERCOT	07TPIT0017	C	Handley	Hurst	18.7	121-150	AC	Unknown	2012
ERCOT	07TPIT0027	UC	CPS Lytle	ETT Lytle	4.0	121-150	AC	Unknown	2012
ERCOT	07TPIT0050	P	Decker Switchyard	Techridge Substation	4.5	121-150	AC	Unknown	2013
ERCOT	07TPIT0060	P	Howard Lane Substation	Techridge Substation	1.7	121-150	AC	Unknown	2015
ERCOT	07TPIT0069	C	Sterrett	Sardis	2.0	121-150	AC	Unknown	2022
ERCOT	07TPIT0073	C	Venus	Webb	11.3	300-399	AC	Unknown	2020
ERCOT	07TPIT0083	C	Picacho	CFE	8.8	121-150	AC	Unknown	2018
ERCOT	07TPIT0115	C	Elgiin Switch	Taylor	11.4	121-150	AC	Unknown	2018
ERCOT	07TPIT0119	C	Lavon Switch	Allen Switch	8.9	121-150	AC	Unknown	2018
ERCOT	07TPIT0122	C	Royse	Dalrock	6.8	121-150	AC	Unknown	2018
ERCOT	07TPIT0126	P	Tricorner	Seagoville	9.4	300-399	AC	Unknown	2014
ERCOT	07TPIT0138	C	Oats (GPL)	Garland Bobtown Tap	1.5	121-150	AC	Unknown	2018
ERCOT	07TPIT0140	C	Trinidad	Watermill	52.0	300-399	AC	Unknown	2014
ERCOT	07TPIT0234	C	Collin Switch	NW. Carrollton	19.3	300-399	AC	Unknown	2022
ERCOT	07TPIT0236	C	N. Terrell Tap	Rose Hill	8.7	121-150	AC	Unknown	2014
ERCOT	08TPIT0007	C	Austin Ranch	Hebron	0.7	121-150	AC	Unknown	2018
ERCOT	08TPIT0018	UC	Uvalde	Castroville	77.5	121-150	AC	Unknown	2012
ERCOT	08TPIT0033	P	Gilleland Substation	Techridge Substation	8.0	300-399	AC	Unknown	2015
ERCOT	08TPIT0034	P	McNeil Substation	Summit Substation	2.0	121-150	AC	Unknown	2012
ERCOT	08TPIT0069	C	Lake Creek	East Waco	10.5	121-150	AC	Unknown	2018
ERCOT	08TPIT0097	UC	Rhome	Roanoke	16.6	121-150	AC	Unknown	2013
ERCOT	08TPIT0104	C	Elgin Switching Station	Elgin	5.9	121-150	AC	Unknown	2014
ERCOT	08TPIT0107	C	Leon	Flat Creek	19.5	121-150	AC	Unknown	2012
ERCOT	08TPIT0109	C	Payne	Collin Switching Station	31.8	121-150	AC	Unknown	2020
ERCOT	08TPIT0111	C	Lufkin Switching Station	Texas Foundries Tap	0.7	121-150	AC	Unknown	2018
ERCOT	08TPIT0153	C	Elkton	Athens North Tap	29.1	121-150	AC	Unknown	2014
ERCOT	09TPIT0011	C	Cagnon	Hill Country	19.5	300-399	AC	Unknown	2020
ERCOT	09TPIT0012	C	Hill Country	Skyline	11.0	300-399	AC	Unknown	2016
ERCOT	09TPIT0037	P	Blossom	Harmony Hills/Skyline	0.1	121-150	AC	Unknown	2014
ERCOT	09TPIT0043	C	Coppell	North Lake	4.8	121-150	AC	Unknown	2018
ERCOT	09TPIT0044	C	E. Richardson	Apollo	2.3	121-150	AC	Unknown	2013
ERCOT	09TPIT0046	C	N. Midlothian	Midlothian TXI Tap	6.2	121-150	AC	Unknown	2018
ERCOT	09TPIT0047	C	N. Waco	NE. Waco	1.9	121-150	AC	Unknown	2020
ERCOT	09TPIT0050	C	Rowlett	Garland Bobtown Tap	4.1	121-150	AC	Unknown	2018
ERCOT	09TPIT0051	C	Saldo Switch	Cedar Valley Switch	7.0	121-150	AC	Unknown	2018
ERCOT	09TPIT0066	C	Boggy Creek	Boggy Creek	3.5	121-150	AC	Unknown	2018
ERCOT	09TPIT0073	P	Switch 1377 at Jupiter	Switch 6612 at Apollo	2.0	121-150	AC	Unknown	2012
ERCOT	09TPIT0074	P	Switch 1378 at Jupiter	Switch 931 at Lawler Tap	1.5	121-150	AC	Unknown	2012
ERCOT	09TPIT0076	P	Switch 932atLawler Tap	Switch 6832 at College	2.0	121-150	AC	Unknown	2012
ERCOT	09TPIT0117	C	Stryker Creek	Dialville	15.2	121-150	AC	Unknown	2014
ERCOT	09TPIT0118	C	Fisher Road	Wichita Falls	1.5	121-150	AC	Unknown	2020
ERCOT	09TPIT0120	C	Sun Switch	Sacroc	12.8	121-150	AC	Unknown	2012
ERCOT	09TPIT0121	C	Sun Switch	Sacroc	1.8	121-150	AC	Unknown	2012
ERCOT	09TPIT0122	C	Shamburger	Tyler NW	6.3	121-150	AC	Unknown	2020
ERCOT	10TPIT0001	C	Trumbo	Leon Creek/Pleasanton	0.1	121-150	AC	Unknown	2016
ERCOT	10TPIT0009	C	Trinity Switch	Hurst	4.0	121-150	AC	Unknown	2018
ERCOT	10TPIT0010	C	Coppell	Roanoke	17.0	121-150	AC	Unknown	2012
ERCOT	10TPIT0013	C	Apollo	East Richardson	1.4	121-150	AC	Unknown	2013

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
ERCOT	10TPIT0017	C	Allen Switch	Collin Junction	9.0	121-150	AC	Unknown	2014
ERCOT	10TPIT0018	C	Austin Ranch	Colony	4.6	121-150	AC	Unknown	2012
ERCOT	10TPIT0019	C	Everman	Cleburne Switch	8.5	121-150	AC	Unknown	2020
ERCOT	10TPIT0020	P	Anna Switch	Krum W. Switch	140.0	300-399	AC	Unknown	2013
ERCOT	10TPIT0024	P	Stoney Ridge Substation	Stoney Ridge Substation	0.1	121-150	AC	Unknown	2012
ERCOT	10TPIT0025	P	Rinard Creek substation	Rinard Creek Substation	0.1	121-150	AC	Unknown	2015
ERCOT	10TPIT0028	C	Escondido	West Batesville	46.2	121-150	AC	Unknown	2018
ERCOT	10TPIT0032	C	Arco (TMPA)	Krugerville	5.6	121-150	AC	Unknown	2012
ERCOT	10TPIT0038	P	Switch 8832 at College	Switch 1364 at Brand	4.2	121-150	AC	Unknown	2013
ERCOT	10TPIT0041	P	Temple Switch	Salado Switch	15.2	300-399	AC	Unknown	2012
ERCOT	10TPIT0049	P	Koppe Bridge	Wellborn	5.8	121-150	AC	Unknown	2012
ERCOT	10TPIT0063	P	Geronimo	CMC	5.5	121-150	AC	Unknown	2014
ERCOT	10TPIT0086	P	East Abilene	Putnam	32.0	121-150	AC	Unknown	2012
ERCOT	10TPIT0091	C	Elm Mott	Waco Northcrest	3.6	121-150	AC	Unknown	2020
ERCOT	10TPIT0095	P	VH Braunig	Grandview	2.1	121-150	AC	Unknown	2012
ERCOT	11TPIT0001	P	Lobo	Rio Bravo	30.0	300-399	AC	Unknown	2016
ERCOT	11TPIT0002	P	Lobo	North Edinburg	163.0	300-399	AC	Unknown	2016
ERCOT	11TPIT0008	P	Rainey St Substation	Rainey St Substation	0.1	121-150	AC	Unknown	2017
ERCOT	11TPIT0009	P	Dunlap Substation	Dunlap Substation	0.1	121-150	AC	Unknown	2014
ERCOT	11TPIT0011	P	Northeast Substation	Northeast Substation	0.1	121-150	AC	Unknown	2017
ERCOT	11TPIT0012	C	Euless	Grapevine Ball Street	5.9	121-150	AC	Unknown	2020
ERCOT	11TPIT0015	C	Sherry	Grand Prairie	11.4	121-150	AC	Unknown	2015
ERCOT	11TPIT0024	C	various	various	5.8	121-150	AC	Unknown	2012
ERCOT	11TPIT0028	C	Allen Switch	West Plano Switch	3.5	121-150	AC	Unknown	2018
ERCOT	11TPIT0032	C	NW Carrollton	Collin	16.9	121-150	AC	Unknown	2014
ERCOT	11TPIT0033	C	Saginaw	American MFG Tap	1.4	121-150	AC	Unknown	2020
ERCOT	11TPIT0047	P	Twin Buttes	Brown	0.2	300-399	AC	Unknown	2012
ERCOT	11TPIT0050	C	Roanoke Switch	Elizabeth Creek	3.8	121-150	AC	Unknown	2015
ERCOT	11TPIT0050	C	Hicks Switch	Elizabeth Creek	10.0	121-150	AC	Unknown	2015
ERCOT	11TPIT0065	C	Ector Co. North Switch	Moss	20.5	121-150	AC	Unknown	2012
ERCOT	11TPIT0072a	UC	Garrott	Midtown	1.5	121-150	AC	Unknown	2012
ERCOT	11TPIT0072b	UC	Midtown	Polk	1.0	121-150	AC	Unknown	2012
ERCOT	11TPIT0076	P	Cottonwood	Dermott	74.2	300-399	AC	Unknown	2012
ERCOT	11TPIT0081	UC	Switch 7512 at Plastipak	Switch 8702 at Shiloh	1.5	121-150	AC	Unknown	2012
ERCOT	11TPIT0085	P	Doedyns	Sioux	5.5	121-150	AC	Unknown	2013
ERCOT	11TPIT0101	P	Reno	Rhome	13.9	121-150	AC	Unknown	2012
ERCOT	11TPIT0110b	P	Weslaco Switch	Valverde	4.5	121-150	AC	Unknown	2012
ERCOT	11TPIT0111	P	Thompson Creek	Koppe Bridge	17.0	121-150	AC	Unknown	2012
ERCOT	11TPIT0114	P	Alberta Switch	Doedyns	3.1	121-150	AC	Unknown	2013
ERCOT	11TPIT0179	C	Hicks Switch	Elizabeth Creek	10.0	121-150	AC	Unknown	2015
ERCOT	12TPIT0004	C	Sulpher Springs	OW Sommers/Kirby	0.1	121-150	AC	Unknown	2018
ERCOT	12TPIT0009	P	Masterson Rd.	Cagnon/Valley/Howard	20.0	121-150	AC	Unknown	2018
ERCOT	12TPIT0015	P	Barney Davis	Laguna	4.2	121-150	AC	Unknown	2014
ERCOT	12TPIT0026	P	Odessa	North McCamey	59.6	300-399	AC	Unknown	2013
ERCOT	12TPIT0027	P	Bakersfield	North McCamey	15.9	300-399	AC	Unknown	2013
ERCOT	12TPIT0028	P	Twin Buttes	Big Hill	31.0	300-399	AC	Unknown	2012
ERCOT	12TPIT0029	P	Big Hill	Kendall	274.0	300-399	AC	Unknown	2013
ERCOT	12TPIT0036	P	Brown	Newton	98.6	300-399	AC	Unknown	2012
ERCOT	12TPIT0037	P	Newton	Killeen Switch	27.9	300-399	AC	Unknown	2012
ERCOT	12TPIT0038	P	Brown	Killeen Switch	126.5	300-399	AC	Unknown	2012
ERCOT	12TPIT0043	UC	Bluff Creek	Brown	86.6	300-399	AC	Unknown	2012
ERCOT	12TPIT0044	UC	Central Bluff	Brown	96.1	300-399	AC	Unknown	2012
ERCOT	12TPIT0046	UC	ZENITH	Gertie	10.0	300-399	AC	Unknown	2012
ERCOT	12TPIT0047	UC	Kluge	Addicks	6.1	121-150	AC	Unknown	2012
ERCOT	12TPIT0047b	UC	ZENITH	ADDICKS	1.5	121-150	AC	Unknown	2012
ERCOT	12TPIT0047c	UC	CAMRON	KLUGE	4.6	121-150	AC	Unknown	2012
ERCOT	12TPIT0049	P	Cottonwood	Silverton	64.5	300-399	AC	Unknown	2013
ERCOT	12TPIT0051	P	Silverton	Nazareth	46.0	300-399	AC	Unknown	2013
ERCOT	12TPIT0052	P	Nazareth	Hereford	25.5	300-399	AC	Unknown	2013
ERCOT	12TPIT0056	P	Grelton	Long Draw	55.4	300-399	AC	Unknown	2013
ERCOT	12TPIT0057	P	Grelton	Odessa	49.9	300-399	AC	Unknown	2013
ERCOT	12TPIT0058	P	Long Draw	Scurry	50.7	300-399	AC	Unknown	2013
ERCOT	12TPIT0059	P	Sand Bluff	Divide	37.0	300-399	AC	Unknown	2013
ERCOT	12TPIT0060	P	Berkat	Sandbluff	28.9	300-399	AC	Unknown	2013
ERCOT	12TPIT0061	P	Sand Bluff	Long Draw	77.4	300-399	AC	Unknown	2013
ERCOT	12TPIT0068	C	South Bend Switch	Morris Sheppard	18.2	121-150	AC	Unknown	2013
ERCOT	12TPIT0072	P	Ferguson	Wirtz	4.0	121-150	AC	Unknown	2012

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
ERCOT	12TPIT0078	C	Southeast Nacogdoches	Lufkin Switch	13.0	300-399	AC	Unknown	2022
ERCOT	12TPIT0079	C	Roanoke Switch	Coppell	19.6	121-150	AC	Unknown	2013
ERCOT	12TPIT0081	P	Merida	Medina Base	0.1	121-150	AC	Unknown	2013
ERCOT	12TPIT0082	P	Hotwells	Ball Park/Deely	0.1	121-150	AC	Unknown	2012
ERCOT	12TPIT0083	P	S 8512 at Firewheel	Lookout	1.3	121-150	AC	Unknown	2012
ERCOT	12TPIT0085	P	Switch 8622 at Apollo	Lookout	2.8	121-150	AC	Unknown	2012
ERCOT	12TPIT0095b	UC	TXGULF	West Columbia	27.5	121-150	AC	Unknown	2012
ERCOT	12TPIT0115	P	Bullick Hollow	Marshall Ford/Balcones	2.3	121-150	AC	Unknown	2012
ERCOT	12TPIT0116	P	Scarscale	El Dorado/S.Houston	0.9	121-150	AC	Unknown	2012
ERCOT	12TPIT0118	C	Elkton	S Tyler	2.8	121-150	AC	Unknown	2012
ERCOT	12TPIT0128	P	WA Parish	Sienna	4.2	121-150	AC	Unknown	2012
ERCOT	12TPIT0134	P	St Jo	Capps Corner	8.6	121-150	AC	Unknown	2012
ERCOT	12TPIT0135	P	Spring	Bridgeport Switch	33.3	121-150	AC	Unknown	2013
ERCOT	12TPIT0136	UC	El Gato	Sioux	5.4	121-150	AC	Unknown	2012
ERCOT	12TPIT0141	C	Dinero	Dinero	0.5	121-150	AC	Unknown	2012
ERCOT	12TPIT0165	P	Fairbanks	Deihl	3.6	121-150	AC	Unknown	2012
ERCOT	12TPIT0165a	P	Deihl	White Oak	4.1	121-150	AC	Unknown	2012
ERCOT	12TPIT0167	P	Crockett	Northside	2.5	121-150	AC	Unknown	2012
ERCOT	12TPIT0169	P	Bellaire	Ulrich	3.4	121-150	AC	Unknown	2012
ERCOT	12TPIT0170	P	Airline	White Oak	3.0	121-150	AC	Unknown	2012
ERCOT	12TPIT0171	P	HO Clarke	Knight	3.9	121-150	AC	Unknown	2012
ERCOT	12TPIT0172	P	Western Dawson	Patricia	7.5	300-399	AC	Unknown	2012
ERCOT	12TPIT0173	P	Austin	Kirby	2.8	121-150	AC	Unknown	2012
ERCOT	12TPIT0178	P	EXTER	HASTINGS	0.1	121-150	AC	Unknown	2012
ERCOT	12TPIT0185	C	Airline	Cabaniss	5.5	121-150	AC	Unknown	2014
ERCOT	13TPIT0011	C	Palo Alto	Leon Creek/Chavaneaus	0.1	121-150	AC	Unknown	2013
ERCOT	13TPIT0016	P	Greens Prairie	Wellborn	4.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0018	P	Bakersfield	Big Hill	112.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0019	P	Riley	Edith Clarke	86.6	300-399	AC	Unknown	2013
ERCOT	13TPIT0020	P	Tesla	Edith Clarke	110.4	300-399	AC	Unknown	2013
ERCOT	13TPIT0021	P	Cottonwood	Edith Clarke	178.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0022	P	Tesla	Riley	131.2	300-399	AC	Unknown	2013
ERCOT	13TPIT0030	P	Dermott	Clear Crossing	180.6	300-399	AC	Unknown	2013
ERCOT	13TPIT0032	P	Edith Clarke	Clear Crossing	158.4	300-399	AC	Unknown	2013
ERCOT	13TPIT0033	P	Clear Crossing	West Shackleford	67.6	300-399	AC	Unknown	2013
ERCOT	13TPIT0035	P	Willow Creek	Dermott Switch	220.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0036	P	Krum West	Riley	322.8	300-399	AC	Unknown	2013
ERCOT	13TPIT0039	P	Hicks Switch	Willow Creek	80.4	300-399	AC	Unknown	2013
ERCOT	13TPIT0042	P	White Deer	Hereford	91.2	300-399	AC	Unknown	2013
ERCOT	13TPIT0045	P	Blumenthal	Kendall CTEC/Mt. Top	8.4	121-150	AC	Unknown	2017
ERCOT	13TPIT0046	P	Flatonia	Yoakum Gartner Road	27.7	121-150	AC	Unknown	2013
ERCOT	13TPIT0047	P	Parkway	EC Mornhinweg	8.0	121-150	AC	Unknown	2014
ERCOT	13TPIT0048	UC	Scurry County South	West Shackelford	204.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0049	UC	West Shackelford	C1 - Sam C2 Navarro	402.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0050	P	Silverton	White Deer	68.2	300-399	AC	Unknown	2013
ERCOT	13TPIT0051	P	Gray	Tesla	218.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0054	P	Gray	White Deer	80.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0055	P	Silverton	Tesla	170.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0058	P	Summit Substation	Williamson Substation	3.5	121-150	AC	Unknown	2014
ERCOT	13TPIT0059	C	Cedar Crest	Industrial	3.2	121-150	AC	Unknown	2020
ERCOT	13TPIT0060	C	Cedar Hill Switch	Mountain Creek	11.4	121-150	AC	Unknown	2014
ERCOT	13TPIT0061	C	Terrell Switch	North Terrell Tap	7.9	121-150	AC	Unknown	2015
ERCOT	13TPIT0066	P	GPI	EC Mornhinweg	2.7	121-150	AC	Unknown	2012
ERCOT	13TPIT0068	P	Helotes	Grissom	0.5	121-150	AC	Unknown	2012
ERCOT	13TPIT0069	P	Panther Springs	Hill Country/Stonegate	0.1	121-150	AC	Unknown	2013
ERCOT	13TPIT0077	P	Kendall	Paleface	56.9	121-150	AC	Unknown	2013
ERCOT	13TPIT0079	P	Alvin	North Alvin	2.1	121-150	AC	Unknown	2014
ERCOT	13TPIT0092	C	Killeen Switch	Harker Heights	15.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0094	C	Lamesa	Ackerly	21.5	121-150	AC	Unknown	2013
ERCOT	13TPIT0099	P	League City	Magnolia	3.6	121-150	AC	Unknown	2013
ERCOT	13TPIT0106	P	Killeen SS	Ding Dong	23.8	121-150	AC	Unknown	2013
ERCOT	13TPIT0108	P	Nelson Sharpe	Ajo	37.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0109	P	Ajo	Rio Hondo	66.7	300-399	AC	Unknown	2013
ERCOT	13TPIT0119	P	Vanderbilt	Ricebird	52.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0121	C	Tilden	TBD	48.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0129	P	George West	Tilden	20.6	121-150	AC	Unknown	2013
ERCOT	13TPIT0130	C	San Miguel	Fashing	20.6	121-150	AC	Unknown	2013

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
ERCOT	13TPIT0131	C	Oaks	Fashing	38.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0135	C	Holt Switch	Goldsmith Substation	5.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0137	C	Odessa North Switch	Goldsmith Substation	17.3	121-150	AC	Unknown	2013
ERCOT	13TPIT0139	C	Olinger	Greenville Interchange	25.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0141	P	NORTON	HACHER/ENPROD	2.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0143	P	El Campo Substation	Nada Substation	17.5	121-150	AC	Unknown	2013
ERCOT	13TPIT0149	P	Oaks	TBD	5.7	121-150	AC	Unknown	2013
ERCOT	13TPIT0152	C	Wink Switch	Loving	16.6	121-150	AC	Unknown	2013
ERCOT	13TPIT0153	C	Moss	Odessa EHV	14.2	121-150	AC	Unknown	2013
ERCOT	13TPIT0158	P	Bruni	MEC Bruni	0.6	121-150	AC	Unknown	2013
ERCOT	13TPIT0162	P	Colorado City	Oncor Breaker Station	2.1	121-150	AC	Unknown	2013
ERCOT	13TPIT0163	C	0	Jan-1900	0.3	121-150	AC	Unknown	2013
ERCOT	14TPIT0003	C	Ranchtown	Helotes/Menger Creek	0.1	121-150	AC	Unknown	2015
ERCOT	14TPIT0004	P	Highway 123	Cushman/New Berlin	6.2	121-150	AC	Unknown	2014
ERCOT	14TPIT0010	C	Handley	Pantego	3.8	121-150	AC	Unknown	2017
ERCOT	14TPIT0011	C	Midland East	Windwood	1.7	121-150	AC	Unknown	2020
ERCOT	14TPIT0012	C	Mountain Creek	Norwood	7.2	121-150	AC	Unknown	2014
ERCOT	14TPIT0013	C	Norwood	East Levee	6.6	121-150	AC	Unknown	2012
ERCOT	14TPIT0014	C	NW Carrollton	Lakepointe (TNMP)	2.1	121-150	AC	Unknown	2014
ERCOT	14TPIT0015	C	Troup	Tyler Grande	13.3	121-150	AC	Unknown	2012
ERCOT	14TPIT0016	C	West Mesquite	Prairie Creek	2.8	121-150	AC	Unknown	2014
ERCOT	14TPIT0020	P	SpencerInt.PSS/EBus982	Pockrus SubPSS/E Bus917	3.3	121-150	AC	Unknown	2015
ERCOT	14TPIT0021	P	Buttercup Substation	Whitestone Substation	2.3	121-150	AC	Unknown	2014
ERCOT	14TPIT0024	P	Lon Hill	Sand Dollar	11.5	300-399	AC	Unknown	2015
ERCOT	14TPIT0025	P	Nopalito	Sand Dollar	14.5	300-399	AC	Unknown	2016
ERCOT	14TPIT0026	P	Sand Dollar	Las Brisas	2.0	300-399	AC	Unknown	2015
ERCOT	14TPIT0029	C	Lake Creek	Robinson	8.3	121-150	AC	Unknown	2018
ERCOT	14TPIT0037	C	Martin Lake	Mount Enterprise	1.2	300-399	AC	Unknown	2012
ERCOT	14TPIT0038	P	Northland Substation	Mag Plant Substation	4.1	121-150	AC	Unknown	2014
ERCOT	14TPIT0040	P	Springwoods	Rayford/Louetta	3.1	121-150	AC	Unknown	2014
ERCOT	14TPIT0041	P	Coliseum	Kirby	4.2	121-150	AC	Unknown	2014
ERCOT	14TPIT0042	P	Five Points	Broadview	9.4	121-150	AC	Unknown	2014
ERCOT	14TPIT0043	C	Skyline	Tri_Conty/Wiederstein	0.1	121-150	AC	Unknown	2014
ERCOT	14TPIT0047	C	W.Denton,N Denton	Arco, Pockrus, Teasley	30.0	121-150	AC	Unknown	2014
ERCOT	14TPIT0050	P	Lon Hill	North Edinburg	122.9	300-399	AC	Unknown	2014
ERCOT	14TPIT0052	C	Midland East	Stanton East	18.6	121-150	AC	Unknown	2014
ERCOT	14TPIT0053	C	Moss	Westover	3.4	121-150	AC	Unknown	2014
ERCOT	14TPIT0054	C	Odessa	Odessa North	7.2	121-150	AC	Unknown	2020
ERCOT	14TPIT0055	C	Seagoville	Wilmer	10.9	121-150	AC	Unknown	2014
ERCOT	14TPIT0056	C	Northaven	Welch	6.0	121-150	AC	Unknown	2014
ERCOT	14TPIT0057	C	Cedar Hill Switch	Mayfield Tap North	4.3	121-150	AC	Unknown	2013
ERCOT	14TPIT0058c	P	JORDAN	BARHIL	0.9	121-150	AC	Unknown	2014
ERCOT	14TPIT0058d	P	JORDAN	NORTON	0.9	121-150	AC	Unknown	2014
ERCOT	14TPIT0058k	P	BENDER	DUNCAN	1.9	121-150	AC	Unknown	2013
ERCOT	14TPIT0058l	P	CROSBY	BENDER	7.9	121-150	AC	Unknown	2013
ERCOT	14TPIT0061	P	Atkins Substation	Briarcrest Substation	3.4	121-150	AC	Unknown	2014
ERCOT	14TPIT0070	P	LaPalma	Palo Alto	12.0	121-150	AC	Unknown	2014
ERCOT	15TPIT0003	P	Sand Dollar	Las Brisas	2.0	300-399	AC	Unknown	2016
ERCOT	15TPIT0004	C	Converse	Deely/Skyline	0.1	121-150	AC	Unknown	2015
ERCOT	15TPIT0007	C	Green Mountain	Stonegate	11.5	121-150	AC	Unknown	2015
ERCOT	15TPIT0015	P	Hastings	Friendswood	7.3	121-150	AC	Unknown	2014
ERCOT	15TPIT0018	P	Kerrville Stadium	Raymond F Barker	10.1	121-150	AC	Unknown	2015
ERCOT	15TPIT0021	P	PHRobinson	South Shore	5.6	121-150	AC	Unknown	2015
ERCOT	15TPIT0022	P	Dobbin	Highway 6	23.0	121-150	AC	Unknown	2015
ERCOT	15TPIT0024	P	Lon Hill	Nelson Sharpe	20.8	300-399	AC	Unknown	2015
ERCOT	15TPIT0025	C	Monticello SES	Monticello Tap	20.1	121-150	AC	Unknown	2015
ERCOT	15TPIT0026	P	Wellborn Susbstation	Millican Substation	3.6	121-150	AC	Unknown	2015
ERCOT	16TPIT0003	P	Longneck	Princeton	3.5	121-150	AC	Unknown	2016
ERCOT	16TPIT0005	P	Farm West	Princeton	7.5	121-150	AC	Unknown	2016
ERCOT	16TPIT0006	P	Climax	Longneck	7.5	121-150	AC	Unknown	2016
ERCOT	16TPIT0007	P	McNeil Substation	Mag Plant Substation	3.2	121-150	AC	Unknown	2016
ERCOT	16TPIT0009	P	Five Points	Westside	3.8	121-150	AC	Unknown	2016
ERCOT	16TPIT0010	C	Hill Country	Bulverde/Stonegate	0.1	121-150	AC	Unknown	2016
ERCOT	16TPIT0016	P	Dobbin	Fish Creek	15.5	121-150	AC	Unknown	2016
ERCOT	16TPIT0023	C	South McAllen	Stewart Road	9.8	121-150	AC	Unknown	2016
ERCOT	16TPIT0024	C	Hamilton Road	Uvalde	53.7	121-150	AC	Unknown	2016
ERCOT	16TPIT0030	P	Loma Alta	N Edinburgh	106.5	300-399	AC	Unknown	2016

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
FRCC	Manatee-Bobwhite	P	Manatee	Bob White	25.0	200-299	AC	1,195.0	2014
FRCC	Bunnell-St. Johns	P	St. Johns	Pellicer	21.5	200-299	AC	759.0	2016
FRCC	Myakka-Englewood	P	Myakka	Englewood	3.3	121-150	AC	357.0	2012
FRCC	Coconut Grove Injection	P	Galloway	Coconut Grove	3.0	121-150	AC	353.0	2020
FRCC	Buckingham 230kV injection	P	Orange River	Collier	1.0	200-299	AC	759.0	2017
FRCC	Garden-Gratigny	P	Gratigny	Country Club	4.5	121-150	AC	287.0	2016
FRCC	Line18Intercon GRECPlant-GVL	P	GREC Plant	Hague Switch Station	0.8	121-150	AC	282/282	2012
FRCC	Greenland Energy Center to Nocatee	P	Greenland Energy	Nocatee	4.4	200-299	AC	668/832	2017
FRCC	LCEC Lake Trafford - Lehigh South Tap	P	Lake Trafford	Lehigh South Tap	13.0	121-150	AC	277/326	2015
FRCC	LCEC Immokalee West - Immokalee	P	Immokalee West	Immokalee	2.7	121-150	AC	396/404	2016
FRCC	LCEC Ave Maria - Carnestown	P	Ave Maria	Carnestown	5.7	121-150	AC	396/404	2019
FRCC	Kathleen to Zephyrhills North	UC	Kathleen	Zephyrhills N	13.0	200-299	AC	919/1000	2013
FRCC	Intercession to Gifford	UC	Intercession City	Gifford	12.0	200-299	AC	1260/1370	2013
FRCC	Central Plaza to 51st St	UC	Central Plaza	51st St	1.8	100-120	AC	392/427	2012
FRCC	Brooksville W.-Brooksville (Rebuild)	UC	Brooksville West	Tangerine	5.1	100-120	AC	392/427	2012
FRCC	115 kV Line Rebuild	P	Havana	Bradfordville West	10.5	100-120	AC	Unknown	2013
FRCC	Atwater-Quincy - 115 kV Line Rebuild	P	Atwater	Quincy	10.9	100-120	AC	Unknown	2014
FRCC	Switch-115 kV Line Rebuild	P	Brooksville West	Weeki Wachee	3.3	100-120	AC	Unknown	2014
FRCC	Jasper-Wrights Chapel Rebuild	P	Jasper	Wrights Chapel	9.6	100-120	AC	460.0	2015
FRCC	115 kV Line Rebuilds	UC	Brooksville	Tangerine	4.0	100-120	AC	392/427	2016
FRCC	Lecanto - Inverness - New 115 kV Line	P	Lecanto	Inverness	11.0	100-120	AC	Unknown	2015
FRCC	Brooksville West - Brooksville - New	P	Brooksville West	Brooksville	0.0	200-299	AC	919/1000	2019
FRCC	Deltona to Orange City- New 115 kV	UC	DELTONA	ORANGE CITY	6.2	100-120	AC	392/427	2013
FRCC	Liberty to Brickyard Tap - new 115 kV	P	BRICKYARDTP1	LIBERTY	23.6	100-120	AC	392/427	2014
FRCC	23_1485_MXA	P	CASSADAGA	MONASTERY	3.3	100-120	AC	203/248	2013
FRCC	24_1485_MXA	P	DELTONA	MONASTERY	4.1	100-120	AC	203/248	2013
FRCC	72_1016_MXA	P	DELEON SPRGS	DELAND WEST	8.3	100-120	AC	300/326	2013
FRCC	236_1123_MXA	P	ORANGE CTY W	HIGHBANKS	3.0	100-120	AC	392/427	2015
FRCC	237_1123_MXA	P	DELTONA	HIGHBANKS	2.0	100-120	AC	300/326	2015
FRCC	278_1662_MXA	P	ORANGE CITY	ORANGE CTY W	1.5	100-120	AC	392/427	2015
FRCC	279_1662_MXA	P	DELTONA	ORANGE CTY W	5.0	100-120	AC	300/326	2015
FRCC	171_1099_MXA	P	DELAND EAST	LK WINNEMISS	3.6	100-120	AC	159/214	2016
FRCC	172_1099_MXA	P	LK HELEN	LK WINNEMISS	3.6	100-120	AC	218/262	2016
FRCC	269_1801T2_MJP	P	HIGGINS 115.00	MORGAN RD SW 115.00	17.0	100-120	AC	160/230	2017
FRCC	270_1801T2_MJP	P	GRIFFIN 115.00	MORGAN RD SW 115.00	27.8	100-120	AC	160/230	2017
FRCC	314_1801T2_MJP	P	MORGAN RD 115.00	MORGAN RD SW 115.00	5.5	100-120	AC	460.0	2015
FRCC	New 230 kV & Disston 230/115 kV	UC	DISSTON	NORTHEAST	4.2	200-299	AC	919/1000	2013
FRCC	88_2154_MXA	P	CITRUS CENT	INTERCESSION CITY	1.6	200-299	AC	1260/1370	2015
FRCC	91_2154_MXA	P	CITRUS CENT	DUNDEE	18.6	200-299	AC	1260/1370	2015
FRCC	Unnamed / Name Unknown	C	Gilchrist Gen Station	Gilchrist E. Switch	10.0	200-299	AC	1,195.0	2017
FRCC	PRECO SR. 70	P	S.R. 70	S.R. 70 Tap	3.0	121-150	AC	115.0	2014
FRCC	CEC Birley	P	Birley	Branford	6.0	100-120	AC	Uknown	2018
FRCC	CEC Brannan Field	P	Brannan Field	Black Creek	0.3	100-120	AC	Uknown	2020
FRCC	LCEC North Trail	P	North Trail	Lee	5.8	121-150	AC	Uknown	2014
FRCC	Unnamed	P	Sub 14 115	Sub 17 115	3.6	100-120	AC	230.0	2012
FRCC	Unnamed / Name Unknown	P	Sub 14 115	Sub 7 115	6.0	100-120	AC	232.0	2013
FRCC	Unnamed / Name Unknown	P	Hopkins-Crawfordville	Sub 5 230	8.0	200-299	AC	458.0	2013
FRCC	Unnamed / Name Unknown	P	Sub 21 115	Sub 17 115	6.0	100-120	AC	232.0	2012
FRCC	Polk 2-5 CC	C	Aspen	Polk	23.5	200-299	AC	1,119.0	2017
FRCC	Polk 2-5 CC	C	Aspen	Mines	15.0	200-299	AC	1,119.0	2017
FRCC	Polk 2-5 CC	C	Aspen	FishHawk (Circuit 1)	6.0	200-299	AC	1,195.0	2017
FRCC	Polk 2-5 CC	C	Aspen	FishHawk (Circuit 2)	6.0	200-299	AC	1,195.0	2017
FRCC	Polk 2-5 CC	C	Polk	Mines	12.0	200-299	AC	1,119.0	2017
FRCC	NO NAME OR NAME UNKNOWN	C	Bayside Power Station	Bayside Biomass	0.7	200-299	AC	729.0	2020
FRCC	Clearview-Himes 138kV circuit	P	Clearvw	Himes	8.2	121-150	AC	329.0	2018
FRCC	Wheeler Road to Thonotosassa	P	WHEELER	THONOTOSASSA	8.3	200-299	AC	1,119.0	2022
FRCC	Pebbledale to Willow Oak	P	PEBB	WILLOW	11.0	200-299	AC	1,119.0	2022
FRCC	Willow Oak to Wheeler Road	P	WILLOW	WHEELER	20.0	200-299	AC	1,093.0	2022
FRCC	Davis Rd-Dale Mabry	P	Davis Rd	Dlmbry	13.0	200-299	AC	1,119.0	2019
FRCC	Polk 2-5 CC	C	Aspen	FishHawk (Circuit 1)	6.0	200-299	AC	1,195.0	2017
FRCC	Polk 2-5 CC	C	Aspen	FishHawk (Circuit 2)	6.0	200-299	AC	1,195.0	2017
FRCC	Polk 2-5 CC	C	Polk	Mines	12.0	200-299	AC	1,119.0	2017
FRCC	Wheeler Road to Thonotosassa	P	WHEELER	THONOTOSASSA	8.3	200-299	AC	1,118.6	2016
FRCC	Clearview-Himes 138kV circuit	P	Clearvw	Himes	8.2	121-150	AC	329.0	2016
FRCC	Pebbledale to Willow Oak	P	PEBB	WILLOW	11.0	200-299	AC	1,118.6	2018
FRCC	Polk to FishHawk 230kV Ckt	P	POLKPLNT	FISHHAWK	30.5	200-299	AC	1,118.6	2018
FRCC	Willow Oak to Wheeler Road	P	WILLOW	WHEELER	20.0	200-299	AC	1,093.5	2018

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FRCC	Davis Rd-Dale Mabry	P	Davis Rd	Dlmbry	13.0	200-299	AC	1,118.6	2019
MISO	Canal-Dunn Road 138 kV	P	Canal	Dunn Road	7.6	121-150	AC	290	2012
MISO	Bemidji-Grand Rapids 230 kV Line	P	Boswell	Wilton	72.0	200-299	AC	495	2012
MISO	Fargo,NDStCloud-MonticelloMN area	UC	Alexandria SS	Quarry (St. Cloud)	65.0	300-399	AC	2085	2013
MISO	Fargo,NDStCloud-MonticelloMN area	UC	Bison	Alexandria SS	130.0	300-399	AC	2085	2015
MISO	Rockdale-West Middleton 345 kV	P	Cardinal (W Middleton)	Rockdale/Albion	35.0	300-399	AC	1,195.0	2013
MISO	Monroe County - Council Creek	P	Monroe County (XEL)	Council Creek (ATC)	17.3	151-199	AC	445	2013
MISO	Crooked Lake - Enterprise Park	P	Crooked Lake	Enterprise Park	4.0	100-120	AC	316	2012
MISO	LaSalle Area Development	P	N. LaSalle	Wedron Fox River	25.0	121-150	AC	266	2012
MISO	LaSalle Area Development	P	Ottawa	Wedron Fox River	8.0	121-150	AC	266	2013
MISO	New Northeast-Oak Grove	UC	Northeast	Oak Grove	5.0	121-150	AC	287/287	2012
MISO	SE Twin Cities-Rochester	P	Hampton Corner	North Rochester	36.0	300-399	AC	2050	2015
MISO	SE TwinCities-Rochester	P	North Rochester	Northern Hills	12.6	151-199	AC	400	2012
MISO	SE TwinCities-Rochester	P	North Rochester	Chester	14.0	151-199	AC	400	2015
MISO	SE TwinCities-Rochester	P	North Rochester	North La Crosse	82.0	300-399	AC	2050	2014
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Brookings County	Lyon County 345 kV	48.1	300-399	AC	2066	2015
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Lyon County	Cedar Mountain	51.9	300-399	AC	2066	2013
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Lyon County	Cedar Mountain	51.9	300-399	AC	2066	2013
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Cedar Mountain	Helena	62.2	300-399	AC	2066	2013
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Cedar Mountain	Helena	62.2	300-399	AC	2066	2013
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Helena	Lake Marion	26.6	300-399	AC	2066	2014
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Lake Marion	Hampton Corner	18.5	300-399	AC	2066	2014
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Lyon County	Hazel	23.5	300-399	AC	2066	2015
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Hazel	Minnesota Valley	6.0	200-299	AC	1558	2015
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Cedar Mountain	Franklin	5.0	100-120	AC	336	2014
MISO	Gibson (Cinergy)-AB Brown-Reid	UC	AB Brown(Vectren)	Reid (BREC)	25.7	300-399	AC	1430/1430	2012
MISO	Hazleton - Salem	P	Salem	Hazleton	81.0	300-399	AC	1195	2012
MISO	Lewis Fields	P	Lewis Fields	Hiawatha	8.5	151-199	AC	1.0	2012
MISO	Morgan Valley (Beverly)	P	Morgan Valley	Beverly	7.9	151-199	AC	335	2013
MISO	Ashland to Rochelle 138	P	Rochelle	Ridgeway	1.0	121-150	AC	282	2012
MISO	Ashland to Rochelle 138	P	Ridgeway	Ashland	1.3	121-150	AC	282	2012
MISO	Bloomington-Hanna 345 kV	C	Bloomington	Pritchard	15.0	300-399	AC	1386	2014
MISO	Bloomington-Hanna 345 kV	C	Pritchard	Franklin Twp	24.0	300-399	AC	956	2014
MISO	Bloomington-Hanna 345 kV	C	Franklin Twp	Hanna	2.8	300-399	AC	1386	2014
MISO	Qualitech to Pittsboro new 138kv line	P	Qualitech	Pittsboro Jct	3.3	121-150	AC	306	2013
MISO	Marshalltown-Franklin	P	Eldora	Iowa Falls Industrial	2.0	151-199	AC	1.0	2012
MISO	Tahoe	P	Tahoe	Wixom	2.6	100-120	AC	351.0	2013
MISO	Clear Lake-Woodmin 115 kV	P	Clear Lake	Woodmin	7.5	100-120	AC	175.0	2012
MISO	Required Gen Int. RequestG362	P	Pleasant Valley	Byron	25.0	151-199	AC	447.0	2012
MISO	AEP Sullivan to DEM Brookston 765	C	DEM Brookston	AEP Sullivan	126.0	600+	AC	4008	2018
MISO	DEM Brookston to Greentown 765	C	DEM Brookston	Greentown	66.0	600+	AC	3576	2018
MISO	Ellendale to Big Stone South	P	Big Stone South	Ellendale	145.0	300-399	AC	Unknown	2019
MISO	Big Stone South to Brookings	P	Big Stone South	Brookings 345 kV double	65.0	300-399	AC	Unknown	2017
MISO	Big Stone South to Brookings	P	Big Stone	Big Stone South	2.0	200-299	AC	Unknown	2017
MISO	Big Stone South to Brookings	P	Big Stone	Big Stone South	2.0	200-299	AC	Unknown	2017
MISO	Meradosia to Ipava	C	Meredosia	Ipava	43.0	300-399	AC	1793	2018
MISO	Meradosia to Pawnee	C	Meredosia	Pawnee	58.0	300-399	AC	1793	2018
MISO	Pana to Mt. Zion	C	Mt. Zion	Pana	30.0	300-399	AC	1793	2020
MISO	Mt. Zion to Kansas	C	Mt. Zion	Kansas	52.0	300-399	AC	1793	2020
MISO	Rising to Sidney 345 kV line	C	Rising	Sidney	27.0	300-399	AC	1793	2017
MISO	Kansas to Sugar Creek	C	Kansas	Sugar Creek	23.7	300-399	AC	1793	2020
MISO	Thomas Hill - Adair - Ottumwa 345	C	Ottumwa	Thomas Hill	105.0	300-399	AC	1793	2017
MISO	Beaver - Davis Besse #2 345kV Line	P	Beaver	Davis Besse	50.0	300-399	AC	Unknown	2014
MISO	Washington Street Substation	P	Line 1364 (new tap)	Washington Street Sub	0.2	121-150	AC	Unknown	2012
MISO	Nortwest Cape Area 345/161 kV Sub	C	Lutesville	Northwest Cape	11.0	300-399	AC	1793	2016
MISO	St. Cloud Loop	P	Benton Co	Mayhew Lake	4.0	100-120	AC	361.0	2012
MISO	New 345kV Supply at Fargo Sub	P	Fargo	Maple Ridge	20.0	300-399	AC	1793	2016
MISO	Essar	P	Boswell	Essar Mine Sub (Calumet)	16.0	200-299	AC	423	2012
MISO	Essar	P	Essar steel plant sub	Shannon	8.0	200-299	AC	423	2015
MISO	Essar	P	Blackberry	Essar Mine Sub (Calumet)	16.0	200-299	AC	465	2012
MISO	Essar	P	Essar Mine Sub)	Essar steel plant	2.5	200-299	AC	465	2012
MISO	Skibo	C	Skibo	Hoyt Lakes	3.0	121-150	AC	202	2012
MISO	Sartell (SEA) 3.0 mile, 115 kV line	P	Sartell	Le Sauk	3.0	100-120	AC	Unknown	2012
MISO	Northport (BENCO) 1 mile, dbl ckt	P	Northport	Northport Tap	1.0	100-120	AC	Unknown	2013
MISO	St. Lawrence Substation&Tap-MVEC	P	St. Lawrence	St. Lawrence Tap	0.5	100-120	AC	Unknown	2017
MISO	South Minneapolis	P	Hiawatha	Midtown	1.3	100-120	AC	360.0	2012
MISO	Dubuque Co -Spring Green 345 kV	C	Spring Green	Dubuque Co	75.1	300-399	AC	2110	2020

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
MISO	Dubuque Co - Spring Green 345 kV	C	Spring Green	Cardinal	28.0	300-399	AC	2110	2020
MISO	Ariel Substation (formerly Holland)	P	Ariel (formerly Holland)	Wheeler	0.1	100-120	AC	Unknown	2012
MISO	Ariel Substation (formerly Holland)	P	Ariel (formerly Holland)	Troy	0.1	100-120	AC	Unknown	2012
MISO	St Antoine-Essex #2 120 kV	C	St Antoine	Essex	5.1	100-120	AC	Unknown	2015
MISO	Raun-Sioux City 345 kV Line	C	Raun	WAPA Sioux City	23.0	300-399	AC	Unknown	2016
MISO	North Alton Substation Supply	P	Wood River-N. Staunton	Tap to Supply N.Alton	4.0	121-150	AC	240	2015
MISO	North Alton Substation Supply	P	Wood River-Stallings	Tap to Supply N. Alton	4.0	121-150	AC	240	2014
MISO	Warrenton-Lincoln Bulk 161 kV Line	C	Warrenton	Lincoln 138-34.5 kV Bulk	10.0	151-199	AC	280	2016
MISO	Bondville-S.W. Campus	P	Bondville	S.W. Campus	8.0	121-150	AC	411	2014
MISO	Quincy Area 345/138 kV Substation	C	Palmyra	Quincy	10.0	300-399	AC	1793	2017
MISO	Newton-Hutsonville-Merom 345 kV	C	Hutsonville Plant	Merom	12.0	300-399	AC	1793	2018
MISO	Quincy-Meredosia 345 kV Line	C	Quincy Area	Meredosia	40.0	300-399	AC	1793	2018
MISO	Fargo-Oak Grove 345 kV Line	C	Fargo	Oak Grove	70.0	300-399	AC	Unknown	2018
MISO	Dickinson 115 kV Loop	P	Dickinson Basin	Dickinson West	5.0	100-120	AC	120	2014
MISO	Dickinson 115 kV Loop	P	North Dickinson	Dickinson West	3.0	100-120	AC	120	2014
MISO	28L reroute	P	Boswell	Nashwaulk	7.5	100-120	AC	144	2012
MISO	N. Lake Geneva-S. Lake Geneva	C	South Lake Geneva	North Lake Geneva	5.0	121-150	AC	293.0	2016
MISO	N LaCrosse-N Madison-Cardinal 345	C	North LaCrosse	North Madison	136.3	300-399	AC	2110	2018
MISO	N LaCrosse-N Madison-Cardinal 345	P	North Madison	Cardinal	20.5	300-399	AC	2110	2018
MISO	Michigan Thumb Wind Zone	P	Rapson (formerly Wyatt)	Baker (formerly Reese)	56.0	300-399	AC	Unknown	2013
MISO	Michigan Thumb Wind Zone	P	Rapson (formerly Wyatt)	Baker (formerly Reese)	56.0	300-399	AC	Unknown	2013
MISO	Michigan Thumb Wind Zone	P	Rapson (formerly Wyatt)	Greenwood	65.0	300-399	AC	Unknown	2015
MISO	Michigan Thumb Wind Zone	P	Rapson (formerly Wyatt)	Greenwood	65.0	300-399	AC	Unknown	2015
MISO	Michigan Thumb Wind Zone	P	Greenwood	Fitz (formerly Saratoga)	19.0	300-399	AC	Unknown	2015
MISO	Michigan Thumb Wind Zone	P	Greenwood	Fitz (formerly Saratoga)	19.0	300-399	AC	Unknown	2015
MISO	West Adair-Palmyra Tap 345 kV Line	C	Adair	Palmyra Tap	63.4	300-399	AC	1793	2018
MISO	Sheldon - Webster 345 kV line	C	Sheldon	Webster	120.0	300-399	AC	1739	2016
MISO	Reqd. for Gen Interconnection	C	Barnhart	Plymouth #4	5.9	121-150	AC	348	2018
MISO	Reqd. for Gen Interconnection	C	Plymouth #4	Howards Grove	3.1	121-150	AC	348	2018
MISO	Reqd. for Gen Interconnection	C	Howards Grove	Erdman	6.6	121-150	AC	348	2018
MISO	Reqd. for Gen Interconnection	C	Barnhart	Branch River	35.5	300-399	AC	1096	2018
MISO	Reqd. for Gen Interconnection	C	Branch River	Forest Jct	12.9	300-399	AC	883	2018
MISO	Reqd. for Gen Interconnection	C	Branch River	Point Beach	1.0	300-399	AC	1096	2018
MISO	Reqd. for Gen Interconnection	C	Branch River	Sheboygan Energy Center	1.0	300-399	AC	1096	2018
MISO	Webster - Hazleton 345 kV line	C	Black Hawk	Webster	91.3	300-399	AC	1739	2015
MISO	Webster - Hazleton 345 kV line	C	Black Hawk	Hazleton	24.0	300-399	AC	1200	2018
Manitoba	Transcona 230-66 Station	P	R32V tap	Transcona	1.0	200-299	AC	658.1	2012
Manitoba	Canexus Upgrade	P	Brandon	Maple Leaf	3.9	100-120	AC	73.0	2012
Manitoba	Transcona 230-66 Station	P	R33V tap	Transcona	1.0	200-299	AC	658.1	2012
Manitoba	Cornwallis Bank Addition	P	Brandon G.S.	Cornwallis	0.2	100-120	AC	189.3	2013
Manitoba	Neepawa 230-66 Station	P	D54C tap	Neepawa 230/66 station	1.0	200-299	AC	564.5	2013
Manitoba	R1 Line Voltage Chng	P	Pointe du Bois	Slave Falls	0.0	121-150	AC	81.7	2014
Manitoba	R2 Line Voltage Chng	P	Pointe du Bois	Slave Falls	0.0	121-150	AC	81.7	2014
Manitoba	S1 Line Voltage Chng	P	Pointe du Bois	Slave Falls	0.0	121-150	AC	95.4	2014
Manitoba	S2 Line Voltage Chng	P	Pointe du Bois	Slave Falls	0.0	121-150	AC	95.4	2014
Manitoba	R1 Line Voltage Chng	P	Pointe du Bois	Slave Falls	6.3	100-120	AC	68.1	2014
Manitoba	R2 Line Voltage Chng	P	Pointe du Bois	Slave Falls	6.3	100-120	AC	68.1	2014
Manitoba	S1 Line Voltage Chng	P	Pointe du Bois	Slave Falls	86.3	100-120	AC	85.3	2014
Manitoba	S2 Line Voltage Chng	P	Pointe du Bois	Slave Falls	86.3	100-120	AC	85.3	2014
Manitoba	Dorsey-Portage 2nd T/L	P	Dorsey	Portage	43.5	200-299	AC	564.5	2015
Manitoba	Rockwood	P	Rockwood	CP17 tap	1.1	100-120	AC	170.3	2015
Manitoba	Rockwood	P	Rockwood	CP17 tap	1.1	100-120	AC	170.3	2015
Manitoba	Rockwood	P	Rockwood	RP16 tap	1.6	100-120	AC	170.3	2015
Manitoba	Pointe du Bois	P	Pointe du Bois	Whiteshell	34.0	100-120	AC	257.3	2015
Manitoba	Lett-St. Vital T/L	P	Letellier	St Vital	77.7	200-299	AC	658.1	2015
Manitoba	Manigotagan Station	P	Pine Falls	Manigotagan	49.7	100-120	AC	127.0	2015
Manitoba	Lav-St. Vital T/L	P	LaVerendrye	St Vital	21.1	200-299	AC	658.1	2015
Manitoba	Bipole 3 / Conawapa	P	Henday	Conawapa Constr Power	0.0	200-299	AC	768.8	2017
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Riel	833.3	400-599	DC	2,000.0	2018
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Henday	18.2	200-299	AC	768.8	2018
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Henday	18.2	200-299	AC	768.8	2018
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Henday	18.2	200-299	AC	768.8	2018
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Henday	18.2	200-299	AC	768.8	2018
Manitoba	Bipole 3 / Conawapa	P	Conawapa	Long Spruce	34.7	200-299	AC	1,029.2	2018
Manitoba	Keeyask	P	Radisson	Keeyask G.S.	23.6	121-150	AC	461.3	2018
Manitoba	Manitoba-US tie	P	Dorsey	Riel	30.9	400-599	AC	3,746.4	2019
Manitoba	Keeyask	P	Keeyask G.S.	Keeyask S.S.	2.0	121-150	AC	436.2	2019

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
Manitoba	Keeyask	P	Keeyask G.S.	Keeyask S.S.	2.0	121-150	AC	436.2	2019
Manitoba	Keeyask	P	Keeyask G.S.	Keeyask S.S.	2.0	121-150	AC	436.2	2019
Manitoba	Keeyask	P	Keeyask	Radisson	23.6	121-150	AC	461.3	2019
Manitoba	Keeyask	P	Keeyask	Radisson	23.6	121-150	AC	461.3	2019
Manitoba	St.Vital-Steinbach	P	St. Vital	Steinbach	27.8	200-299	AC	420.0	2020
Manitoba	Manitoba-US tie	C	Riel	Shannon	80.0	200-299	AC	1,732.0	2022
MAPP	AMES Plant - NE Ankeny 161 kV Line	C	AMES Plant 161 kV Sub.	NE Ankeny 161 kV Sub.	22.0	151-199	AC	332.0	2013
MAPP	AVS-NESET 345	P	AVS 345	NESET 345	190.0	300-399	AC	1,200.0	2016
MAPP	Snake Creek-Neset 115	P	Snake Creek 115	Neset 115	160.0	100-120	AC	140.0	2014
MAPP	Blaisdell-Berhold 115	P	Blaisdell 115	Berthold 115	15.0	100-120	AC	140.0	2013
MAPP	S.Gap-Watford City 115	C	S.Gap 115	Watford City 115	40.0	100-120	AC	140.0	2013
MAPP	Culbertson-Grenora	C	Culbertson 115	Grenora 115	45.0	100-120	AC	140.0	2014
MAPP	CapX	UC	Brookings County, SD	Hampton, MN	230.0	300-399	AC	1,000.0	2015
MAPP	CENTER-GRAND FORKS 345 KV LINE	P	CENTER 345 KV SUB	PRAIRIE 345 KV SUB	250.0	300-399	AC	1,206.0	2013
MAPP	BEMIDJI - CASS LAKE 230 KV LINE	P	WILTON 230 KV SUB	CASS LAKE 230 KV SUB	19.0	200-299	AC	641.0	2012
MAPP	CASS LAKE - BOSWELL 230 KV LINE	P	CASS LAKE 230 KV SUB	BOSWELL 230 KV SUB	51.0	200-299	AC	641.0	2012
MAPP	Big Bend-Lower Brule	P	Lower Brule dbl ckt	Big Bend	2.1	200-299	AC	Unknown	2016
MAPP	Big Bend-Lower Brule	P	Lower Brule	Fort Thompson	9.3	200-299	AC	Unknown	2016
MAPP	Big Bend-Lower Brule	P	Lower Brule	Reliance	19.5	200-299	AC	Unknown	2016
SaskPower	Unnamed / Name Unknown	P	Aberdeen Switch St.	Martinsville Switch St.	25.0	200-299	AC	765.0	2013
SaskPower	Unnamed / Name Unknown	P	Aberdeen Switch St.	Wolverine Switch St.	68.0	200-299	AC	765.0	2013
SaskPower	Unnamed / Name Unknown	P	Elstow Switch St.	Wolverine Switch St.	31.0	121-150	AC	382.0	2013
SaskPower	Unnamed / Name Unknown	P	Elstow Switch St.	Wolverine Switch St.	0.0	121-150	AC	166.0	2013
SaskPower	Unnamed / Name Unknown	P	Pasqua Switch Station	Swift Current Switch St.	140.0	200-299	AC	765.0	2016
SaskPower	Unnamed / Name Unknown	P	Pasqua Switch Station	Swift Current Switch St.	0.0	121-150	AC	134.0	2016
SaskPower	Unnamed / Name Unknown	P	Pasqua Switch Station	Swift Current Switch St.	140.0	121-150	AC	382.0	2016
SaskPower	Unnamed / Name Unknown	P	Peebles Switch St.	Tantallon Switch St.	84.0	200-299	AC	765.0	2013
SaskPower	Unnamed / Name Unknown	C	Beatty Switching Station	Wolverine Switch St.	99.0	200-299	AC	765.0	2016
SaskPower	Unnamed / Name Unknown	C	Condie Switching Station	Pasqua Switching Station	43.0	200-299	AC	765.0	2016
SaskPower	Unnamed / Name Unknown	C	Brada Switching Station	Martinsville Switch St.	80.0	200-299	AC	765.0	2016
Maritimes	Coleson Cove to Salisbury 345 kV	C	Coleson Cove	Salisbury	103.0	300-399	AC	1,076.0	2016
Maritimes	New Minas Sub	P	Canaan Road	Prospect Road	2.5	121-150	AC	170.0	2012
Maritimes	Harbour East	P	Dartmouth East	Eastern Passage	10.6	121-150	AC	170.0	2013
Maritimes	NS/NB Tie	C	Onslow	Salisbury	100.0	300-399	AC	1,076.0	2016
Maritimes	NS - NL Tie	C	Newfoundland	Nova Scotia	100.0	200-299	DC	Unknown	2018
Maritimes	Y-104	C	West Royalty	Church Road	50.0	121-150	AC	189.0	2017
New England	Rochester Area	P	Rochester Substation	North Rochester Sub.	6.9	100-120	AC	238.0	2015
New England	MPRP	P	Orrington	Coopers Mills	54.0	100-120	AC	380.0	2014
New England	MPRP	P	Larrabee Road	Middle St	5.7	100-120	AC	282.0	2014
New England	MPRP	P	Middle St	Lewiston Lower	1.2	100-120	AC	282.0	2014
New England	MPRP	P	Larrabee Road	Livermore Falls	24.1	100-120	AC	282.0	2013
New England	MPRP	P	Livermore Falls	Rumford IP	20.4	100-120	AC	282.0	2013
New England	Section 241 Somerset Co. Reinforce	P	Wyman Hydro	Rice Rips Tap	39.0	100-120	AC	282.0	2012
New England	Greater Rhode Island Upgrades	P	Brayton Point Station	Somerset	3.4	100-120	AC	Unknown	2014
New England	Central/Western MA upgrades	P	Millbury	Tower	6.9	100-120	AC	259.0	2013
New England	Merrimack Valley/North Shore	P	King St	West Amesbury	7.2	100-120	AC	232.0	2012
New England	Central/Western MA upgrades	P	Otter River	East Winchendon	5.7	100-120	AC	262.0	2016
New England	Worcester Area Upgrades	P	North Bloomingdale	Vernon	3.6	100-120	AC	179.0	2012
New England	Greater Rhode Island Upgrades	P	Somerset	Bell Rock	3.7	100-120	AC	Unknown	2014
New England	Boston Area Enhancements	P	West Walpole	Holbrook	0.0	100-120	AC	Unknown	2014
New England	Mid Cape Reliability Project	C	Canal	Barnstable	0.0	100-120	AC	Unknown	2013
New England	Greater Boston - North	C	Wakefield	Everett	0.0	100-120	AC	Unknown	2015
New England	Greater Boston - Western Suburbs	C	Woburn	Hartwell Ave	6.4	100-120	AC	Unknown	2015
New England	Pittsfield/Greenfield Area	P	Northfield Mt. Sub.	Erving Substation	1.2	100-120	AC	696.0	2014
New England	Stamford Area	C	Glenbrook Substation	Southend S/S	0.0	100-120	AC	Unknown	2022
New England	Lyman Substation	C	Holyoke Fairmont South	Lyman Substation	0.0	100-120	AC	Unknown	2022
New England	Granite/Middlesex	C	Granite S/S	Middlesex S/S	16.0	200-299	AC	496.0	2022
New England	Long Term Lower SEMA	P	Carver	Bourne	17.9	300-399	AC	2,169.0	2014
New England	NEEWs	P	West Farnum S/S	CT/RI Border	17.7	300-399	AC	2,172.0	2015
New England	NEEWs	P	Millbury S/S	West Farnum S/S	20.2	300-399	AC	2,172.0	2015
New England	NEEWs	UC	Kent County	West Farnum S/S	21.4	300-399	AC	1,353.0	2013
New England	NEEWs	P	Card S/S	Lake Road S/S	29.3	300-399	AC	2,420.0	2015
New England	NEEWs	P	Lake Road S/S	CT/RI Border	7.6	300-399	AC	2,420.0	2017
New England	NEEWs	P	Frost Bridge S/S	North Bloomfield S/S	35.4	300-399	AC	2,420.0	2016
New England	NEEWs	P	Manchester	Meekville Jct.	2.7	300-399	AC	2,420.0	2013
New England	NEEWs	P	North Bloomfield S/S	CT/MA Border	12.0	300-399	AC	2,420.0	2013
New England	NEEWs	UC	Agawam S/S	Ludlow S/S	16.9	300-399	AC	2,420.0	2013
New England	MPRP	UC	Orrington S/S	Albion Road S/S	59.0	300-399	AC	2,151.0	2013

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
New England	MPRP	UC	Albion Road S/S	Coopers Mills S/S	21.0	300-399	AC	2,151.0	2014
New England	MPRP	UC	Larrabee Road S/S	Coopers Mills S/S	34.3	300-399	AC	2,151.0	2014
New England	MPRP	UC	Larrabee Road S/S	Surowiec S/S	17.0	300-399	AC	2,151.0	2012
New England	MPRP	UC	Surowiec S/S	Raven Farm S/S	12.4	300-399	AC	2,151.0	2013
New England	MPRP	P	Maguire Road S/S	South Gorham S/S	21.0	300-399	AC	2,151.0	2012
New England	MPRP	P	Maguire Road S/S	Three Rivers Switchyard	19.2	300-399	AC	2,151.0	2013
New England	Greater Boston N-S. Central	P	Scobie S/S	PSNH/NGRID Border	10.8	300-399	AC	2,420.0	2016
New England	Northern Pass Transmission Project	C	Quebec/NH Border	Franklin	140.0	300-399	DC	Unknown	2016
New England	Northern Pass Transmission Project	C	Franklin	Deerfield	40.0	300-399	AC	Unknown	2016
New England	8300 Line Configuration	P	Grand Isle S/S	Mill River	0.1	100-120	AC	340.0	2013
New England	Lakewood Reinforcement	P	Lake Road S/S	Section 833B Tap	4.0	100-120	AC	282.0	2013
New England	Merrimack Valley/N.Shore Reliability	P	Mystic	Everett	0.5	100-120	AC	153.0	2012
New England	Greater Boston - South	P	Medway #65	Border with Milford	2.0	100-120	AC	325.0	2013
New England	Greater Boston - South	P	Border with Bellingham	Border with Milford	2.0	100-120	AC	325.0	2013
New England	NEEWs	P	ANP Blackstone	NEA Bellingham Tap	1.2	100-120	AC	Unknown	2012
New England	Greater Boston - North	C	Woburn	Tewsbury	0.0	300-399	AC	Unknown	2016
New England	Greater Boston - North	C	Woburn	N. Cambridge	0.0	100-120	AC	Unknown	2016
New England	Greater Boston - Western Suburbs	C	Woburn	Burlington	3.7	100-120	AC	Unknown	2013
New England	Greater Boston - Central	C	Mystic	Chelsea	0.0	100-120	AC	Unknown	2016
New England	Greater Boston - Central	C	Mystic	Woburn	0.0	100-120	AC	Unknown	2016
New England	Greater Boston - Central	C	Needham	Baker Street	0.0	100-120	AC	Unknown	2016
New England	Greater Boston - Western Suburbs	C	Sudbury	Hudson	0.0	100-120	AC	Unknown	2016
New England	Mid Cape Reliability Project	C	Bourne	Falmouth Tap	0.0	100-120	AC	Unknown	2015
New England	Mid Cape Reliability Project	C	Bourne	Oak Street	0.0	100-120	AC	Unknown	2015
New England	Mid Cape Reliability Project	C	Oak Street	Barnstable	0.0	100-120	AC	Unknown	2015
New England	Long Term Lower SEMA	P	Carver	Oak Street	30.7	300-399	AC	2,169.0	2012
New England	NEEWs	P	Agawam S/S	CT/MA Border	6.0	300-399	AC	2,420.0	2013
New England	Western New Hampshire Solution	C	Fitzwilliam S/S	Monadnock S/S	2.5	100-120	AC	Unknown	2016
New England	Southern New Hampshire Solution	C	Scobie S/S	Huse Rd. S/S	6.0	100-120	AC	Unknown	2016
New England	Seacost New Hampshire Solution	C	Madbury S/S	Portsmouth S/S	13.0	100-120	AC	Unknown	2016
New England	Seacost New Hampshire Solution	C	Scobie S/S	Chester S/S	6.0	100-120	AC	Unknown	2016
New England	SWCT Advanced Solutions	C	Glenbrook S/S	South End S/S	1.8	100-120	AC	Unknown	2022
New England	Line Configuration	P	Coopers Mills	Highland Substation	0.0	100-120	AC	Unknown	2013
New England	Central Vermont Solution	P	West Rutland	Coolidge	27.0	300-399	AC	Unknown	2016
New England	Cental Vermont Soluton	P	Coolidge	Ascutney	15.0	100-120	AC	Unknown	2016
New York	Unnamed / Name Unknown	P	Quebec - NY	Astoria Annex 345kV	0.0	300-399	DC	Unknown	2016
New York	Unnamed / Name Unknown	P	St. Pool	High Falls	5.6	100-120	AC	1,114.0	2020
New York	Unnamed / Name Unknown	P	High Falls	Kerhonkson	10.0	100-120	AC	1,114.0	2020
New York	Unnamed / Name Unknown	P	Kerhonkson	Honk Falls	9.9	100-120	AC	1,114.0	2020
New York	Unnamed / Name Unknown	P	Modena	Galeville	4.6	100-120	AC	1,114.0	2020
New York	Unnamed / Name Unknown	P	Galeville	Kerhonkson	9.0	100-120	AC	1,851.0	2013
New York	Unnamed / Name Unknown	P	Shoreham	Brookhaven	0.0	121-150	AC	1,851.0	2013
New York	Unnamed / Name Unknown	P	Shoreham	Wildwood	1.0	121-150	AC	1,851.0	2013
New York	Unnamed / Name Unknown	P	Wildwood	Brookhaven	6.3	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Holbrook	Holtsville GT	0.0	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Holbrook	West Bus	0.2	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	West Bus	Holtsville GT	0.1	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Sill Rd	Holtsville GT	0.0	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Sill Rd	West Bus	9.4	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	West Bus	Holtsville GT	0.1	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Pilgrim	Holtsville GT	0.0	121-150	AC	2,087.0	2013
New York	Unnamed / Name Unknown	P	Pilgrim	West Bus	11.7	121-150	AC	2,087.0	2013
New York	Unnamed / Name Unknown	P	Riverhead	Wildwood	10.6	121-150	AC	1,399.0	2014
New York	Unnamed / Name Unknown	P	Moses	Willis	0.0	200-299	AC	876.0	2013
New York	Unnamed / Name Unknown	P	Moses	Willis	37.1	200-299	AC	876.0	2013
New York	Unnamed / Name Unknown	P	Moses	Willis	37.1	200-299	AC	876.0	2013
New York	Unnamed / Name Unknown	P	Oakdale	Fraser	56.9	300-399	AC	2,100.0	2012
New York	Unnamed / Name Unknown	P	Oakdale	Clarks Corners	21.2	300-399	AC	2,020.0	2012
New York	Unnamed / Name Unknown	P	Spier	Rotterdam	32.7	100-120	AC	Unknown	2015
New York	Unnamed / Name Unknown	P	Burns	Corporate Drive	4.0	121-150	AC	Unknown	2014
New York	Unnamed / Name Unknown	P	BPS Station	Rochester	3.8	300-399	AC	2,177.0	2016
New York	Unnamed / Name Unknown	UC	Wood Street	Carmel	1.3	100-120	AC	Unknown	2012
New York	Unnamed / Name Unknown	UC	Wood Street	Katonah	11.7	100-120	AC	Unknown	2012
New York	Unnamed / Name Unknown	UC	Greenbush	Hudson	0.0	100-120	AC	Unknown	2012
New York	Unnamed / Name Unknown	UC	Greenbush	Klinekill Tap	20.3	100-120	AC	Unknown	2012
New York	Unnamed / Name Unknown	UC	Klinekill Tap	Hudson	6.1	100-120	AC	Unknown	2012
Ontario	Unnamed / Name Unknown	UC	Allanburg TS	Middleport TS	93.0	200-299	AC	964.0	2022

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
Ontario	East-West Tie	C	Lakehead TS	Wawa TS	240.0	200-299	AC	Unknown	2017
Ontario	London West	C	London	Sarnia/Chatham	43.0	200-299	AC	Unknown	2017
Ontario	Unnamed / Name Unknown	C	Dryden area	Pickle Lake	180.0	200-299	AC	Unknown	0
Québec	Eastmain-1-A - La Sarcelle	UC	La Sarcelle	Eastmain-1	63.4	300-399	AC	885.2	2012
Québec	Lac Alfred Wind Project	UC	Lac Alfred W.F.	Rimouski Tap	18.6	300-399	AC	1,454.2	2012
Québec	Bloom Lake Mining Project	UC	Mines Bloom Lake	Bloom Lake Tap	1.1	300-399	AC	1,115.0	2012
Québec	Des Moulins Wind Project	UC	Des Moulins W.F.	Antoine-Lemieux Tap	1.9	200-299	AC	594.1	2012
Québec	Line 2359 Dismantlement	UC	Francheville T.S.	Sorel T.S.	0.0	200-299	AC	Unknown	2012
Québec	Francheville 230 kV Project	UC	Francheville T.S.	L2356 Tower 6	2.0	200-299	AC	Unknown	2012
Québec	New Richmond Wind Project	UC	New Richmond W.F.	Cascapédia Tap	6.6	200-299	AC	701.7	2012
Québec	Limoilou 230/25 kV Project	UC	Québec/Stadacona	Limoilou T.S.	0.6	200-299	AC	470.0	2012
Québec	Eleonore Mining 120 kV Project	UC	Eastmain-1	Mines Opinaca	39.5	100-120	AC	195.4	2012
Québec	St-Robert-Bellarmin Wind Project	UC	St-Robert-Bellarmin W.F.	Bolduc T.S.	20.5	100-120	AC	313.0	2012
Québec	Montérégie Wind Project	UC	Montérégie W.F.	St-Rémi Tap	0.3	100-120	AC	Unknown	2012
Québec	Neubois 120/25 kV T.S. Project	UC	Ste-Marie	Neubois T.S.	29.8	100-120	AC	366.1	2012
Québec	Neubois 120/25 kV T.S. Project	UC	Ste-Marie T.S.	Scott T.S.	0.0	100-120	AC	Unknown	2012
Québec	De l'Érable Wind Project	UC	De l'Érable W.F.	Kingsey Tap	7.5	100-120	AC	Unknown	2012
Québec	Sheldrake Private Hydro Project	UC	Sheldrake G.S.	Sheldrake Tap	2.8	151-199	AC	309.7	2012
Québec	Québec Lithium	UC	Québec Lithium (HV)	Québec Lithium Tap	0.9	100-120	AC	255.0	2012
Québec	Seigneurie-de-Beaupré Wind	UC	Seigneurie-de-Beaupré	Beaupré Tap	9.3	300-399	AC	Uknown	2013
Québec	Charlevoix 315 kV T.S. Looping	UC	Charlevoix T.S.	Bersimis/Laurentides 315	3.7	300-399	AC	877.3	2013
Québec	St-Bruno 315/25 kV T.S. project	UC	St-Bruno T.S.	St-Bruno Tap	1.2	300-399	AC	1,107.8	2013
Québec	Bélanger 315/25 kV T.S. Project	P	Bélanger 315/25 T.S.	Bélanger Tap	2.5	300-399	AC	Unknown	2013
Québec	Bélanger 315/25 kV T.S. Project	R	Bélanger 120/25 T.S.	Montréal-Nord T.S.	0.0	100-120	AC	Unknown	2013
Québec	Charlesbourg 230/25 kV T.S. project	C	Charlesbourg T.S.	Charlesbourg Tap	7.5	200-299	AC	697.2	2013
Québec	Arnaud Mining Project	C	Mines Arnaud	Mines Arnaud Tap	0.6	151-199	AC	Unknown	2013
Québec	Massif-du-Sud Wind Project	UC	Massif-du-Sud	Massif-du-Sud Tap	13.0	100-120	AC	Unknown	2013
Québec	Joanna 120 kV Mining Project	C	Mines Joanna	Joanna Tap	0.9	100-120	AC	231.0	2013
Québec	St-Damase Wind Project (Third call)	P	St-Damase	St-Damase Tap	0.3	100-120	AC	Unknown	2013
Québec	Viger-Denonville Wind (3rd call)	P	Viger-Denonville	Denonville Tap	0.1	100-120	AC	Unknown	2013
Québec	Lachenaie 315/25 T.S. project	P	Lachenaie T.S.	Lachenaie Tap	0.6	300-399	AC	1,113.4	2013
Québec	Val-Jalbert Private Hydro Integration	P	Val-Jalbert G.S.	Val-Jalbert Tap	0.1	151-199	AC	Unknown	2013
Québec	Blainville 315/25 kV T.S. project	P	Blainville T.S.	Blainville Tap	7.2	300-399	AC	Unknown	2014
Québec	Pierre-Le Gardeur 315/120 kV Project	P	Pierre-Le Gardeur 315	Mauricie Tap	0.4	300-399	AC	1,113.4	2014
Québec	Pierre-Le Gardeur 315/120 kV Project	P	Pierre-Le Gardeur 120	120 kV system	1.0	100-120	AC	Unknown	2014
Québec	Mauricie-Lanaudière 315 kV Project	C	Lanaudière T.S.	Mauricie Tap	3.1	300-399	AC	Unknown	2014
Québec	Pierre-Le Gardeur 315/120 kV	C	Pierre-Legardeur120 T.S.	St-Sulpice 120 T.S.	17.4	100-120	AC	Unknown	2014
Québec	Lefrançois 315/25 kV T.S. Project	C	Lefrançois T.S.	Lefrançois Tap	2.5	300-399	AC	877.3	2014
Québec	Rivière-du-Moulin Wind Project	P	Rivière-du-Moulin	Rivière-du-Moulin Tap	15.5	300-399	AC	Unknown	2014
Québec	Romaine Complex Hydro Project	UC	La Romaine-2	Arnaud	162.2	300-399	AC	2,980.6	2014
Québec	Romaine Complex Hydro Project	UC	La Romaine-2	La Romaine-2 G.S.	1.7	300-399	AC	Unknown	2014
Québec	Aux Outardes 735 kV Project	P	Micoua	Aux Outardes	9.3	600+	AC	6,954.9	2014
Québec	Chigoubiche 161/25 kV T.S.	R	Chigoubiche T.S.	St-Félicien T.S.	0.0	151-199	AC	Unknown	2014
Québec	Black Rock Metal Project	C	Black Rock	Black Rock Tap	15.6	151-199	AC	310.0	2014
Québec	Obatogamau T.S. Retirement	R	Obatogamau T.S.	Obatogamau Tap	0.0	151-199	AC	Unknown	2014
Québec	Crevier Project	C	Normandin T.S.	Crevier (HV client)	49.4	151-199	AC	310.0	2014
Québec	Vent-du-Kempt Wind Project	P	Vent-du-Kempt	Vent-du-Kempt Tap	6.2	100-120	AC	230.8	2014
Québec	Bedford 230/120 kV Upgrade Project	C	St-Césaire 120 T.S.	Bedford 120 T.S.	43.5	100-120	AC	Unknown	2014
Québec	Temiscouata Wind Project (Third call)	P	Temiscouata	Temiscouata Tap	0.4	100-120	AC	Unknown	2014
Québec	Palmarolle 120 kV Reinforcement	UC	Palmarolle T.S.	Figuery T.S.	24.9	100-120	AC	366.1	2014
Québec	Alcoa Baie Comeau Aluminum Project	C	Alcoa	Hauterive T.S.	25.5	151-199	AC	570.3	2015
Québec	Duchesnay 315/25 kV T.S. Project	P	Duchesnay T.S.	Duchesnay Tap	6.2	300-399	AC	1,113.4	2015
Québec	Northern Pass Project	C	Des Cantons735/300 T.S.	Québec - US Border	93.2	300-399	DC	Unknown	2015
Québec	Limoilou 230/25 kV Project	C	Québec	Limoilou T.S.	5.3	200-299	AC	Unknown	2015
Québec	Limoilou 230/25 kV Project	C	Limoilou T.S.	Stadacona T.S.	0.5	200-299	AC	Unknown	2015
Québec	Alouette Phase 3 Aluminum Smelter	C	Alouette	Arnaud T.S.	17.5	151-199	AC	1,140.9	2015
Québec	Grande-Baie Project Rio Tinto Alcan	C	Saguenay T.S.	Grande-Baie	50.0	151-199	AC	570.0	2015
Québec	Renard Mining Project	C	Mines Renard	Nikamo T.S.	103.1	151-199	AC	195.0	2015
Québec	La lièvre 120/25 kV T.S. Project	C	High Falls (Brookfiled)	La lièvre T.S.	5.0	100-120	AC	Unknown	2015
Québec	Dumont Mining Project	C	Figuery T.S.	Mines Dumont	10.0	100-120	AC	366.1	2015
Québec	Waswanipi 315/25 kV T.S.	C	Waswanipi T.S.	Waswanipi Tap	1.2	300-399	AC	Unknown	2015
Québec	Romaine Complex Hydro Project	P	Romaine-1	Romaine-2	17.4	300-399	AC	Unknown	2016
Québec	Romaine Complex Hydro Project	P	Romaine-1	Romaine-1 G.S.	0.6	300-399	AC	Unknown	2016
Québec	Baie-St-Paul 315/25 kV T.S. Project	C	Baie-St-Paul T.S.	Baie-St-Paul Tap	6.2	300-399	AC	1,022.0	2016
Québec	Maniwaki-Paugan 120 kV Line Project	C	Maniwaki T.S.	Paugan G.S.	7.5	100-120	AC	Unknown	2016
Québec	Mont-Laurier-Maniwaki 120 kV Line	C	Maniwaki T.S.	Mont-Laurier T.S.	30.3	100-120	AC	Unknown	2016
Québec	St-Jérôme Project	C	Grand-Brûlé T.S.	St-Jérôme T.S.	49.7	100-120	AC	Unknown	2016

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
Québec	Chamouchouane-Montréal 735 kV	C	Chamouchouane 735 kV	Bout-de-l'Ile 735 kV	229.9	600+	AC	Unknown	2017
Québec	Romaine Complex Hydro Project	P	Montagnais T.S.	Romaine-4	108.7	300-399	AC	Unknown	2017
Québec	Romaine Complex Hydro Project	P	Romaine-3	Romaine-4	19.9	300-399	AC	Unknown	2017
Québec	Vimont 315/25 kV T.S. Project	C	Vimont 315 T.S.	Vimont Tap	0.4	300-399	AC	Unknown	2017
Québec	De Lorimier 315/25 kV T.S. Project	C	Viger	De Lorimier 315 T.S.	3.7	300-399	AC	Unknown	2017
Québec	De Lorimier 315/25 kV T.S. Project	C	Viger	De Lorimier 315 T.S.	3.7	300-399	AC	Unknown	2017
Québec	De Lorimier 315/25 kV T.S. Project	R	Notre-Dame 120 T.S.	De Lorimier 120 T.S.	0.0	100-120	AC	Unknown	2017
Québec	Fleury 315/25 kV T.S. Project	C	Fleury 315/25 T.S.	Charland T.S.	7.5	300-399	AC	Unknown	2017
Québec	Fleury 315/25 kV T.S. Project	C	Fleury 315/25 T.S.	Beaumont T.S.	2.5	300-399	AC	Unknown	2017
Québec	Fleury 315/25 kV T.S. Project	R	Fleury 120/25 T.S.	Reed T.S.	0.0	100-120	AC	Unknown	2017
Québec	Fleury 315/25 kV T.S. project	R	Fleury 120/25 T.S.	Charland T.S.	0.0	100-120	AC	Unknown	2017
Québec	Abitibi subregion reinforcement	C	Abitibi 735 kV	Duchemin 735/315 kV	88.2	600+	AC	2,980.6	2018
Québec	Abitibi subregion reinforcement	C	Duchemin 315 kV	Lebel 315 kV	11.2	300-399	AC	Unknown	2018
Québec	Abitibi subregion reinforcement	C	Lebel 315 kV	Poularies 315 kV	211.3	300-399	AC	Unknown	2018
Québec	Arnaud-2 project	C	Arnaud	Arnaud-2	9.3	600+	AC	2,980.6	2018
Québec	Alouette reinforcement	C	Arnaud-2	Alouette	15.5	300-399	AC	Unknown	2018
Québec	Alouette reinforcement	C	Arnaud-2	Alouette	0.0	151-199	AC	Unknown	2018
Québec	Alouette reinforcement	C	Arnaud-2	Alouette	15.5	300-399	AC	Unknown	2018
PJM	Capital Ave	C	Capital Ave	Capital Ave Substation	0.1	121-150	AC	159.0	2012
PJM	Chums Corner	C	Chums Corner Jct	Chums Corner Substation	1.1	121-150	AC	159.0	2012
PJM	Eagle's Landing	C	Eagle's Landing Jct	Eagle's Landing Sub.	0.1	121-150	AC	159.0	2012
PJM	Fausett	C	Fausett Jct	Fausett Substation	0.1	121-150	AC	159.0	2012
PJM	Hawthorne	C	Hawthorne Jct	Hawthorne Substation	0.0	121-150	AC	159.0	2012
PJM	Maines Rd	C	Maines Rd Jct	Maines Rd Substation	0.1	121-150	AC	159.0	2012
PJM	Ryno	C	Ryno Jct	Ryno Substation	0.1	121-150	AC	159.0	2012
PJM	Scenic Lake	C	Scenic Lake Jct	Scenic Lake Substation	0.1	121-150	AC	159.0	2012
PJM	Egan	C	Egan Jct	Egan Substation	2.5	121-150	AC	159.0	2012
PJM	Forest Grove	C	Forest Grove Jct	Forest Grove Substation	1.0	121-150	AC	159.0	2012
PJM	Haakwood	C	Haakwood Jct	Haakwood Substation	0.0	121-150	AC	159.0	2012
PJM	Snyder	C	Snyder Jct	Snyder Substation	0.0	121-150	AC	159.0	2012
PJM	Unnamed / Name Unknown	C	Wheatland	Bloomington	61.0	300-399	AC	1,200.0	2012
PJM	Unnamed / Name Unknown	C	Brookston	Frankfort	53.0	300-399	AC	1,793.0	2016
PJM	Unnamed / Name Unknown	C	Thorntown	Qualitech	23.0	300-399	AC	1,793.0	2016
PJM	Unnamed / Name Unknown	C	Brookston	Reynolds	0.5	300-399	AC	1,793.0	2016
PJM	Unnamed / Name Unknown	C	Avon Industrial Park	A new Distr. Sub.	2.6	300-399	AC	306.0	2020
PJM	St. Antoin - Essex #2	C	St Antoine	Essex #2	5.1	100-120	AC	240.0	2015
PJM	Quaker - Southfield #2	C	CTL 18	Southfield	0.4	100-120	AC	242.0	2015
PJM	n1174	C	Carlos Junction	Dans Mountain	5.0	121-150	AC	Unknown	2013
PJM	n1174	C	Ridgeley	Dans Mountain	5.0	121-150	AC	Unknown	2013
PJM	n1350	C	Sutton	Sutton Dam	0.1	121-150	AC	Unknown	2015
PJM	n1350	C	Sutton Hill	Sutton Dam	0.1	121-150	AC	Unknown	2015
PJM	Unnamed / Name Unknown	C	Broadview	Clark	5.0	121-150	AC	278/338	2019
PJM	Unnamed / Name Unknown	C	Broadview	East Springfield	3.5	121-150	AC	160/192	2019
PJM	Unnamed / Name Unknown	C	Broadview	Tangy	3.5	121-150	AC	160/192	2019
PJM	Unnamed / Name Unknown	C	Broadview	Urbana	5.0	121-150	AC	278/338	2019
PJM	Unnamed / Name Unknown	C	Midway	Wauseon	0.0	121-150	AC	151/166	2018
PJM	Unnamed / Name Unknown	C	Napoleon	Richland	0.0	121-150	AC	151/166	2018
PJM	Unnamed / Name Unknown	C	Richland	Stryker	0.0	121-150	AC	151/166	2018
PJM	Line 701 Upgrade	C	West Nyack	Harings Corner	0.3	121-150	AC	236.0	2018
PJM	Z75 Extension	C	Toytota	Scott	14.0	121-150	AC	287.0	2016
PJM	Quaker - Southfield #2	C	Quaker	CTL 18	7.1	100-120	AC	320.0	2015
PJM	Pere Marquette - Keystone 230	C	Pere Marquette	Keystone	75.0	200-299	AC	576.0	2015
PJM	n1647	C	U2-041	East Lima / Marysville	0.0	300-399	AC	Unknown	2012
PJM	n1397	C	Browns Run	Rhodes Lane	0.1	400-599	AC	Unknown	2015
PJM	n1397	C	Yukon	Rhodes Lane	0.1	400-599	AC	Unknown	2015
PJM	b1267.1	P	Coldspring	Erdman	10.3	100-120	AC	Unknown	2015
PJM	b1267.1	P	Coldspring	Erdman	10.3	100-120	AC	Unknown	2015
PJM	b0729	P	Perryman	Harford	0.4	100-120	AC	Unknown	2013
PJM	b0729	P	Perryman	Harford	0.4	100-120	AC	Unknown	2013
PJM	b1084	P	Deer Park	Northwest	3.0	100-120	AC	Unknown	2014
PJM	b1729	P	Burton	Oakwood	3.5	100-120	AC	Unknown	2014
PJM	Unnamed / Name Unknown	P	Rutland	Algonquin	5.5	121-150	AC	376.0	2012
PJM	Unnamed / Name Unknown	P	Rutland	Algonquin	5.5	121-150	AC	376.0	2012
PJM	Unnamed / Name Unknown	P	Qualitech	Pittsboro	3.3	121-150	AC	306.0	2013
PJM	Unnamed / Name Unknown	P	Ridgeway	Ashland	1.3	121-150	AC	282.0	2012
PJM	Unnamed / Name Unknown	P	Ridgeway	Rochelle	1.0	121-150	AC	282.0	2012
PJM	Unnamed / Name Unknown	P	Vincennes	Vigo Street	2.3	121-150	AC	287.0	2012

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
PJM	toi1340.2	P	Plum	Universal	7.3	121-150	AC	Unknown	2022
PJM	s0059	P	East Petersburg	Howmet	0.9	121-150	AC	193.0	2013
PJM	s0059	P	Dillersville	Howmet	1.6	121-150	AC	193.0	2013
PJM	b0210.1	P	Orchard	Cumberland	2.7	200-299	AC	Unknown	2013
PJM	b1172	P	Hopewell	Bull Hill	5.0	200-299	AC	Unknown	2012
PJM	s0169	P	Dickerson	Edwards Ferry	1.0	200-299	AC	Unknown	2013
PJM	s0169	P	Pleasant View	Edwards Ferry	1.0	200-299	AC	Unknown	2013
PJM	b1309	P	Lakeside	Northwest	11.5	200-299	AC	Unknown	2013
PJM	b1312	P	Charlottesville	Hollymeade	1.0	200-299	AC	Unknown	2014
PJM	b1312	P	Gordonsville	Hollymeade	1.0	200-299	AC	Unknown	2014
PJM	b1215	P	Trowbridge	Winfall	0.0	200-299	AC	Unknown	2014
PJM	b1332	P	Cannon Branch	Cloverhill	2.0	200-299	AC	Unknown	2015
PJM	b1332	P	Liberty	Cloverhill	5.8	200-299	AC	Unknown	2015
PJM	b1321	P	North Anna	Oak Green	28.2	200-299	AC	Unknown	2015
PJM	b1331	P	Shawboro	Aydlett	16.0	200-299	AC	Unknown	2015
PJM	b1508.1	P	Harrisonburg	Endless Caverns	19.8	200-299	AC	Unknown	2015
PJM	b1697	P	Idylwood	Clark	4.0	200-299	AC	Unknown	2016
PJM	b1794	P	Hornertown	Battleboro	33.0	200-299	AC	Unknown	2016
PJM	b1794	P	Rocky Mount	Battleboro	8.6	200-299	AC	Unknown	2016
PJM	b1125	P	Buzzard Point	Ritchie	10.8	200-299	AC	Unknown	2014
PJM	b1813.3	P	West Pocono	North Pocono	10.6	200-299	AC	648.0	2017
PJM	b1813.6	P	Jenkins	West Pocono	14.7	200-299	AC	648.0	2016
PJM	b1813.8	P	Paupack	North Pocono	21.9	200-299	AC	648.0	2015
PJM	n3053.4	P	Eldred	W3-022	0.0	200-299	AC	648.0	2014
PJM	Unnamed / Name Unknown	P	Speed	New Albany SW (LGEE)	1.9	300-399	AC	1,244.0	2012
PJM	Unnamed / Name Unknown	P	Sugar Creek	Kansas (NIPS)	35.0	300-399	AC	1,793.0	2019
PJM	Reynolds_BurrOak_Hiple_345kV_Line	P	Reynolds	Burr Oak	47.0	300-399	AC	1314-1773	2019
PJM	Reynolds_BurrOak_Hiple_345kV_Line	P	Burr Oak	Hiple	53.0	300-399	AC	1314-1773	2019
PJM	n1323	P	Mt. Storm	Bismark	1.0	400-599	AC	Uknown	2012
PJM	n1323	P	Doubs	Bismark	1.0	400-599	AC	Uknown	2012
PJM	b1188	P	Loudoun	Brambleton	1.0	400-599	AC	Uknown	2014
PJM	b1188	P	Pleasant View	Brambleton	1.0	400-599	AC	Uknown	2014
PJM	Unnamed / Name Unknown	P	Greentown	Reynold (NIPS)	66.0	600+	AC	3,576.0	2018
PJM	b1674	P	Englishtown	Wyckoff Street	15.0	100-120	AC	140.0	2013
PJM	b1608	P	Everets	Mainesburg	0.0	100-120	AC	Uknown	2015
PJM	b1608	P	Mansfield	Mainesburg	0.0	100-120	AC	Uknown	2015
PJM	b1277	P	Osterburg East	Bedford North	5.7	100-120	AC	229/278	2013
PJM	Michigan Region 4 Thumb Loop	P	Wyatt	Rapson 1	2.0	100-120	AC	196.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Rapson	Harbor Beach	2.0	100-120	AC	137.0	2015
PJM	b0838	P	Softshell	Bonnyman	24.0	121-150	AC	669.0	2014
PJM	b0840	P	Twin Branch	East Elkhart	18.0	121-150	AC	205.0	2013
PJM	b1032.2	P	Biers Run	Hopetown	3.0	121-150	AC	389.0	2015
PJM	b1032.2	P	Biers Run	Circleville	20.0	121-150	AC	389.0	2015
PJM	b1032.3	P	Hopetown	Delano	3.0	121-150	AC	389.0	2015
PJM	b1034.1	P	South Canton	West Canton	4.1	121-150	AC	251.0	2014
PJM	b1034.2	P	West Canton	Wayview	0.0	121-150	AC	251.0	2014
PJM	b1034.1	P	Wagenhals	Wayview	9.0	121-150	AC	251.0	2014
PJM	b1035	P	West Millersport	Gahanna	15.0	121-150	AC	359.0	2014
PJM	b1052	P	Hyatt	Sawmill	5.3	121-150	AC	388.0	2014
PJM	b1430	P	Benton Harbor	Riverside	0.0	121-150	AC	167.0	2015
PJM	b1430	P	East Watervliet	Benton Harbor / Hartford	5.0	121-150	AC	296.0	2015
PJM	b1466.1	P	Adams	Seaman / Waverly	0.0	121-150	AC	150.0	2014
PJM	b1466.5	P	Seaman	Highland	17.4	121-150	AC	223.0	2014
PJM	b1466.7	P	Hillsboro	Highland	3.0	121-150	AC	223.0	2014
PJM	b1467.2	P	Laporte Jct	Olive / Michigan City	0.0	121-150	AC	156.0	2015
PJM	b1470.1 /s0350	P	Sundial	Baileysville	6.4	121-150	AC	296.0	2015
PJM	b1470.3 /s0350	P	Sundial	Kanawha River	0.0	121-150	AC	223.0	2015
PJM	b1470.3 /s0350	P	Sundial	Baileysville	0.0	121-150	AC	223.0	2015
PJM	b1490	P	Robison Park	Auburn	15.0	121-150	AC	388.0	2015
PJM	b1490	P	Kendallville	Albion / Garrett North	0.0	121-150	AC	251.0	2015
PJM	b1662	P	Pemberton	Cherry Creek	4.0	121-150	AC	251.0	2015
PJM	b1663	P	Jacksons Ferry	Wythe	28.0	121-150	AC	388.0	2015
PJM	b1666	P	Findlay Tap	Fostoria Central	0.0	121-150	AC	150 / 167	2015
PJM	b1666	P	Findlay Tap	New Liberty / N.Findlay	0.0	121-150	AC	150 / 167	2015
PJM	b1666	P	Findlay Tap	Findlay Center/NE Findlay	0.0	121-150	AC	205.0	2015
PJM	b1667	P	Melmore	Tiffin Center	7.2	121-150	AC	Uknown	2015
PJM	b1667	P	Tiffin Center	Fremont Center	12.6	121-150	AC	Uknown	2015
PJM	b1667	P	Melmore	Greenlawn	0.0	121-150	AC	205.0	2015

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
PJM	b1667	P	Melmore	West End Fostoria	0.0	121-150	AC	167.0	2015
PJM	b1667	P	Melmore	Howard	0.0	121-150	AC	167.0	2015
PJM	b1781	P	Trail Fork	Baileysville	0.0	121-150	AC	302.0	2013
PJM	b1781	P	Trail Fork	Tazewell	0.0	121-150	AC	302.0	2013
PJM	b1783	P	Lonesome Pine	Tazewell / Bluefield	0.0	121-150	AC	251.0	2015
PJM	b1783	P	South Bluefield	S.Princeton / Bluefield	0.0	121-150	AC	205 / 251	2015
PJM	b1818	P	Lincoln	Allen	4.5	121-150	AC	Uknown	2016
PJM	b1818	P	Sterling	Allen	4.5	121-150	AC	Uknown	2016
PJM	b1818	P	Milan	Allen	4.5	121-150	AC	Uknown	2016
PJM	b1818	P	Timber Switch	Allen	4.5	121-150	AC	Uknown	2016
PJM	s0251	P	Vassell	Delaware	17.4	121-150	AC	251.0	2014
PJM	s0352	P	Ware Road	Waverly / Adams-Seaman	0.0	121-150	AC	150.0	2012
PJM	s0353	P	I. U. Purdue	Spy Run / Robison Park	6.5	121-150	AC	Uknown	2014
PJM	s0353.3	P	Industrial Park	Spy Run / McKinley	0.0	121-150	AC	296 /251	2014
PJM	b0873	P	Glasgow	Mount Pleasant	12.0	121-150	AC	Uknown	2013
PJM	b0879	P	Wye Mills	Church	7.0	121-150	AC	Uknown	2015
PJM	b0737	P	Indian River	Bishop	12.0	121-150	AC	Uknown	2012
PJM	toi355	P	Wye Mills	Easton	4.0	121-150	AC	Uknown	2018
PJM	s0198	P	Albright	Altamont	0.0	121-150	AC	Uknown	2014
PJM	s0180	P	Greenbrier	Harts Run	0.0	121-150	AC	Uknown	2013
PJM	s0198	P	Mt. Zion	Altamont	0.0	121-150	AC	Uknown	2014
PJM	b1023.3	P	Osage	502 Junction	7.0	121-150	AC	Uknown	2013
PJM	b0674	P	Osage	Whiteley	12.0	121-150	AC	Uknown	2013
PJM	s0110	P	Pursley	Holbrook	5.0	121-150	AC	Uknown	2016
PJM	s0180	P	Ronceverte	Harts Run	0.0	121-150	AC	Uknown	2013
PJM	b1023.3	P	Whiteley	502 Junction	6.0	121-150	AC	Uknown	2013
PJM	s0110	P	Whiteley	Holbrook	5.0	121-150	AC	Uknown	2016
PJM	0	P	Ashtabula	Stacy	10.0	121-150	AC	103/133	2013
PJM	b1281	P	Avery	Hayes	6.3	121-150	AC	149/194	2014
PJM	Unnamed / Name Unknown	P	Barberton	South Akron	8.1	121-150	AC	232/281	2017
PJM	Unnamed / Name Unknown	P	Bluebell	New Berlin Lake Area Sub	1.0	121-150	AC	102/132	2015
PJM	b1691	P	Bluebell	South Akron	31.6	121-150	AC	163/197	2016
PJM	Unnamed / Name Unknown	P	Chamberlin	Shalersville	2.5	121-150	AC	278/338	2014
PJM	Unnamed / Name Unknown	P	Delta	Fulton	1.0	121-150	AC	278/343	2013
PJM	b1692	P	East Akron	Knox	0.3	121-150	AC	185/189	2013
PJM	s0370	P	East Springfield	London	15.5	121-150	AC	199/240	2014
PJM	Unnamed / Name Unknown	P	Fulton	Swanton	1.0	121-150	AC	278/343	2013
PJM	b1585	P	Galion	Longview	0.0	121-150	AC	200/242	2012
PJM	b1281	P	Greenfield	Hayes	4.4	121-150	AC	149/194	2014
PJM	b1281	P	Greenfield	Hayes	4.4	121-150	AC	278/338	2014
PJM	s0369	P	London	Tangy	38.6	121-150	AC	199/240	2014
PJM	Unnamed / Name Unknown	P	Mayfield	Stacy	10.0	121-150	AC	103/133	2013
PJM	Unnamed / Name Unknown	P	Niles	New Berlin Lake Area Sub	1.0	121-150	AC	102/132	2015
PJM	b1290	P	Niles	Salt Springs #2	3.2	121-150	AC	278/339	2013
PJM	b1692	P	Sammis	Knox	0.3	121-150	AC	185/189	2013
PJM	b1398.3	P	Mickleton	Deptford	1.7	200-299	AC	Uknown	2015
PJM	b0497	P	Conastone	Graceton	8.6	200-299	AC	Uknown	2014
PJM	b0877	P	Vienna	Steele	28.0	200-299	AC	Uknown	2017
PJM	b0750	P	Vienna	Loretto	16.0	200-299	AC	Uknown	2018
PJM	b0750	P	Loretto	Piney Grove	6.0	200-299	AC	Uknown	2018
PJM	b0673	P	Elko	Carbon Center Jct	5.8	200-299	AC	Uknown	2016
PJM	b1153	P	Conemaugh	Seward	2.4	200-299	AC	719/882	2014
PJM	b0910	P	Jenkins	Stanton	8.6	200-299	AC	648.0	2014
PJM	b0717	P	Brunner Island	West Shore	16.0	200-299	AC	648.0	2013
PJM	b1154	P	West Orange	Roseland	4.5	200-299	AC	Uknown	2014
PJM	b1154	P	West Orange	Roseland	4.5	200-299	AC	Uknown	2014
PJM	b1154	P	Roseland	Sewaren	29.8	200-299	AC	Uknown	2014
PJM	b1155	P	Camden	Burlington	13.7	200-299	AC	Uknown	2014
PJM	b1155	P	Camden	Cuthbert Blvd.	4.5	200-299	AC	Uknown	2014
PJM	b1304.1	P	Hudson	Kearny	2.0	200-299	AC	Uknown	2014
PJM	b1304.1	P	Roseland	Kearny	21.9	200-299	AC	Uknown	2014
PJM	b1304.3	P	Bergen	Athenia	10.0	200-299	AC	Uknown	2015
PJM	b1398	P	Gloucester	Cuthbert Blvd.	4.5	200-299	AC	Uknown	2015
PJM	b1398.3	P	Mickleton	Gloucester	9.0	200-299	AC	Uknown	2015
PJM	b1787	P	Cox's Corner	Lumberton	4.3	200-299	AC	Uknown	2016
PJM	n1035	P	Athenia	Bergen	10.0	200-299	AC	Uknown	2014
PJM	b1032.1	P	Don Marquis	Biers Run	0.0	300-399	AC	1,219.0	2015

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PJM	b1032.1	P	Biers Run	Bixby	0.0	300-399	AC	1,235.0	2015
PJM	b1817	P	East Elkhart	Cook / Hiple	0.0	300-399	AC	1,409.0	2016
PJM	b1819	P	Robison Park	Sorenson	24.0	300-399	AC	Uknown	2016
PJM	s0251	P	Vassell	Hyatt	0.0	300-399	AC	1,409.0	2014
PJM	s0251	P	Vassell	Corridor	0.0	300-399	AC	1,235.0	2014
PJM	s0251	P	Vassell	Corridor	8.0	300-399	AC	1,409.0	2014
PJM	n1650	P	Kewanee	Nelson TSS155	51.0	300-399	AC	Uknown	2012
PJM	n1651	P	Kewanee	Collins	85.0	300-399	AC	Uknown	2012
PJM	Unnamed / Name Unknown	P	Allen Junction	Fulton	0.0	300-399	AC	1370/1646	2013
PJM	b1282	P	Beaver	Hayes	32.9	300-399	AC	1542/1878	2014
PJM	b1283	P	Chamberlin	Hanna	0.7	300-399	AC	1380/1646	2014
PJM	Unnamed / Name Unknown	P	Chamberlin	Shalersville	9.5	121-150	AC	617/751	2014
PJM	b1282	P	Davis Besse	Hayes	32.0	300-399	AC	1542/1878	2014
PJM	Unnamed / Name Unknown	P	Fulton	Midway	0.0	300-399	AC	1370/1646	2013
PJM	Unnamed / Name Unknown	P	Fulton	North Star Steel	0.0	300-399	AC	1370/1646	2013
PJM	n2176	P	G689	Highland	1.3	300-399	AC	1559/1899	2014
PJM	n2176	P	G689	Sammis	1.3	300-399	AC	1559/1899	2014
PJM	b1283	P	Hanna	Mansfield	0.7	300-399	AC	1380/1646	2014
PJM	Michigan Region 4 Thumb Loop	P	Baker	Rapson 1	63.9	300-399	AC	2,568.0	2013
PJM	Michigan Region 4 Thumb Loop	P	Baker	Rapson 2	63.9	300-399	AC	2,568.0	2013
PJM	Michigan Region 4 Thumb Loop	P	Rapson	Greenwood	55.0	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Rapson	Banner	33.2	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	SE Sandusky	Greenwood	21.8	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Greenwood	Fitz 2	13.2	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Greenwood	Fitz 3	13.2	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Belle River	Fitz 1	3.5	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Belle River	Fitz 2	3.5	300-399	AC	2,568.0	2015
PJM	s0104	P	Cranberry	Cabot	0.1	400-599	AC	2800/3600	2012
PJM	s0104	P	Cranberry	Wylie Ridge	0.1	400-599	AC	2800/3600	2012
PJM	b0284.1	P	Conemaugh	Jacks Mountain	0.0	400-599	AC	2,932.0	2017
PJM	b0284.1	P	Jacks Mountain	Juniata	0.0	400-599	AC	2,932.0	2017
PJM	b0284.1	P	Jacks Mountain	Juniata	0.0	400-599	AC	2,932.0	2017
PJM	b0284.1	P	Keystone	Jacks Mountain	0.0	400-599	AC	2,932.0	2017
PJM	b0478	P	Susquehanna	Roseland	146.0	400-599	AC	3,005.0	2015
PJM	b0478	P	Susquehanna	Roseland	146.0	400-599	AC	Uknown	2015
PJM	b1659.14	P	Dumont	Sorenson	7.0	600+	AC	6,249.0	2015
PJM	b1659.14	P	Marysville	Sorenson	7.0	600+	AC	6,249.0	2015
PJM	s0251	P	Vassell	Kammer / Maliszewski	0.0	600+	AC	4257/4174	2014
PJM	TOI152	P	Westport	Wilkens Ave	3.0	100-120	AC	Uknown	2014
PJM	Gratiot Wind Park	UC	Titibawassee	Begole	5.0	121-150	AC	394.0	2012
PJM	AB Brown to Reid 345kv	UC	Reid	Brown	24.5	300-399	AC	1,400.0	2012
PJM	s0356	UC	Wayman Switch	Sand Hill / Kammer	0.0	121-150	AC	205.0	2012
PJM	Birchwood	UC	Birchwood Jct	Birchwood Substation	0.0	121-150	AC	159.0	2012
PJM	Ratigan	UC	Ratigan Jct	Ratigan Substation	0.1	121-150	AC	159.0	2012
PJM	Unnamed / Name Unknown	UC	Noblesville Gen. Station	Geist	0.6	200-299	AC	319.0	2012
PJM	s0124	UC	Fredrickburg	Garrisonville	1.0	200-299	AC	Uknown	2012
PJM	s0124	UC	Possum Point	Garrisonville	1.0	200-299	AC	Uknown	2012
PJM	b1071	UC	Landstown	Virginia Beach	11.0	200-299	AC	Uknown	2012
PJM	b1096	UC	Loudoun	Middleburg	10.0	200-299	AC	Uknown	2013
PJM	s0121	UC	Loudoun	Cochran Mill	1.0	200-299	AC	Uknown	2014
PJM	s0121	UC	Pleasant View	Cochran Mill	1.0	200-299	AC	Uknown	2014
PJM	b0503	UC	Carson	Forbes	2.8	121-150	AC	Uknown	2012
PJM	b0503	UC	Oakland	Carson	2.0	121-150	AC	Uknown	2013
PJM	Unnamed / Name Unknown	UC	Cranberry	Hoytdale	2.2	121-150	AC	278/338	2012
PJM	Unnamed / Name Unknown	UC	Cranberry	Maple	0.6	121-150	AC	278/338	2012
PJM	Unnamed / Name Unknown	UC	Cranberry	Pine #1	2.2	121-150	AC	278/338	2012
PJM	Unnamed / Name Unknown	UC	Cranberry	Pine #2	0.6	121-150	AC	278/338	2012
PJM	b0814	UC	Essex	Kearny	2.0	121-150	AC	Uknown	2013
PJM	b1100	UC	Bayonne	Marion	4.4	121-150	AC	Uknown	2012
PJM	Simpson – Batavia	UC	Simpson	Batavia	22.3	121-150	AC	345.0	2012
PJM	s0178	UC	Bradford/Clay Tap	Clay	0.0	200-299	AC	328.0	2013
PJM	s0178	UC	Colora/Clay Tap	Clay	7.0	200-299	AC	463.0	2013
PJM	b0526	UC	Richie	Benning	5.3	200-299	AC	Uknown	2012
PJM	toi334.2	UC	Arsenal	Logans Ferry	12.0	300-399	AC	Uknown	2016
PJM	DWSD SubA Trf 3 Addition	P	Waterman Bus 3	Zug B Bus 102	1.0	100-120	AC	343.0	2013
PJM	Unnamed / Name Unknown	X	Somerset	O19	0.1	100-120	AC	Uknown	0
PJM	Unnamed / Name Unknown	X	Amos	Welton Spring	175.0	600+	AC	6,500.0	0

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PJM	Unnamed / Name Unknown	X	Welton Spring	Kemptown	100.0	600+	AC	6,500.0	0
PJM	Unnamed / Name Unknown	X	Amos	Welton Spring	175.0	600+	AC	6,500.0	0
PJM	Unnamed / Name Unknown	X	Welton Spring	Kemptown	100.0	600+	AC	6,500.0	0
SERC-E	Mull 100 kV Lines	U	Hickory Tie	Newton Tie Tap	0.0	100-120	AC	200.0	2012
SERC-E	Swain 161-66 kV Tie Station	UC	West Mill Tie	Swain Tie	17.0	151-199	AC	275.0	2013
SERC-E	Pinewood 100 kV Lines	U	Lawsons Fork Tie	Pinewood Ret Tap	0.0	100-120	AC	225.0	2014
SERC-E	Beulah 100 kV Lines	U	Stamey Tie	EU # 18 Tap	0.0	100-120	AC	375.0	2014
SERC-E	Mayo 100 kV Lines	U	Dan River Steam Sta	Madison Tie	0.0	100-120	AC	225.0	2013
SERC-E	Monroe 100 kV Lines	U	Lancaster Mn	Monroe Mn	0.0	100-120	AC	175.0	2014
SERC-E	Oaklawn 100 kV Lines	U	Lakewood Tie	Bancroft Ret Tap	0.0	100-120	AC	375.0	2014
SERC-E	Odell 100 kV Lines	U	Winecoff Tie	Westfork Sw Sta	0.0	100-120	AC	225.0	2014
SERC-E	Caesar 230 kV Lines (Pisgah - Shiloh)	U	Shiloh Sw Sta	Pisgah Tie	0.0	200-299	AC	850.0	2013
SERC-E	London Creek 230 kV Lines	U	Riverview Sw Sta	Peach Valley Tie	0.0	200-299	AC	750.0	2020
SERC-E	Oakvale 100 kV Lines	U	Oakvale Tie	Shady Grove Tie	0.0	100-120	AC	375.0	2018
SERC-E	Greenville-Kinston Dupont 230 kV	C	Greenville	Kinston DuPont	30.0	200-299	AC	615.0	2017
SERC-E	Harris - RTP 230 kV line	P	Harris	RTP	22.0	200-299	AC	1,195.0	2014
SERC-E	Asheboro-Asheboro East 115kV, S.	U	Asheboro	Asheboro East	0.0	100-120	AC	308.0	2016
SERC-E	Asheboro-Asheboro East 115kV, N.	U	Asheboro	Asheboro East (2)	0.0	100-120	AC	308.0	2019
SERC-E	Asheville-Enka 115 kV line	P	Asheville	Enka (2)	10.0	100-120	AC	320.0	2012
SERC-E	Folkstone 230 kV, Loop-in 230 kV line	P	Folkstone	Castle Hayne/Jacksonville	16.0	100-120	AC	308.0	2012
SERC-E	A M Williams-Cainhoy	P	A M Williams	Cainhoy	11.0	200-299	AC	352.0	2014
SERC-E	Urquhart-Graniteville	U	Urquhart	Graniteville (2)	0.0	200-299	AC	950.0	2016
SERC-E	VC Summer-Killian	P	VC Summer	Killian	38.0	200-299	AC	950.0	2015
SERC-E	VC Summer #2-Lake Murray	P	VC Summer #2	Lake Murray (2)	23.0	200-299	AC	950.0	2015
SERC-E	VC Summer-VC Summer #2	UC	VC Summer	VC Summer #2	1.0	200-299	AC	950.0	2013
SERC-E	VC Summer-VC Summer #2	UC	VC Summer	VC Summer #2 (2)	1.0	200-299	AC	950.0	2013
SERC-E	Lyles-Denny Terrace	P	Lyles	Denny Terrace	3.0	200-299	AC	950.0	2015
SERC-E	Pepperhill-Summerville	P	Pepperhill	Summerville	7.0	200-299	AC	950.0	2014
SERC-E	VC Summer #2-St. George	P	VC Summer #2	St. George	135.0	200-299	AC	950.0	2018
SERC-E	VC Summer-VC Summer #2	P	VC Summer	VC Summer #2 (3)	1.0	200-299	AC	950.0	2018
SERC-E	AM WIlliams-Cainhoy	P	AM WIlliams	Cainhoy (2)	9.0	200-299	AC	510.0	2017
SERC-E	Belvedere-Stevens Creek	R	Belvedere	Stevens Creek	0.0	100-120	AC	130.0	2013
SERC-E	Belvedere-Stevens Creek	P	Belvedere	Stevens Creek	8.0	100-120	AC	474.0	2013
SERC-E	VC Summer-Parr	R	VC Summer	Parr	0.0	200-299	AC	475.0	2013
SERC-E	VC Summer-Parr	R	VC Summer	Parr (2)	0.0	200-299	AC	475.0	2013
SERC-E	Canadys-St. George	R	Canadys	St. George	0.0	200-299	AC	352.0	2018
SERC-E	Canadys-St. George	P	Canadys	St. George	8.0	200-299	AC	950.0	2018
SERC-E	St. George-Summerville	U	St. George	Summerville	0.0	200-299	AC	950.0	2018
SERC-E	Saluda Hydro-Ga Pac	U	Saluda Hydro	Ga Pac	0.0	100-120	AC	474.0	2018
SERC-E	Lyles-Denny Terrace	R	Lyles	Denny Terrace	0.0	100-120	AC	187.0	2015
SERC-E	Lyles-Denny Terrace	R	Lyles	Denny Terrace	0.0	200-299	AC	510.0	2015
SERC-E	Lyles-Denny Terrace	P	Lyles	Denny Terrace	3.0	100-120	AC	377.0	2015
SERC-E	Lyles-Williams Street	U	Lyles	Williams Street	0.0	100-120	AC	237.0	2015
SERC-E	Killian-Blythewood	P	Killian	Blythewood	7.0	100-120	AC	472.0	2014
SERC-E	Lake Murray-Saluda Hydro	U	Lake Murray	Saluda Hydro	0.0	100-120	AC	236.0	2015
SERC-E	Lake Murray-McMeekin	U	Lake Murray	McMeekin	0.0	100-120	AC	236.0	2015
SERC-E	Pomaria-V C Summer	P	Pomaria	V C Summer (2)	8.0	200-299	AC	956.0	2014
SERC-E	V C Summer-Winnsboro	P	V C Summer	Winnsboro	14.0	200-299	AC	956.0	2013
SERC-E	Winnsboro-Richburg	P	Winnsboro	Richburg	27.0	200-299	AC	956.0	2014
SERC-E	Richburg-Flat Creek	P	Richburg	Flat Creek	32.0	200-299	AC	956.0	2015
SERC-E	Pomaria-Sandy Run	C	Pomaria	Sandy Run	55.0	200-299	AC	956.0	2016
SERC-E	Sandy Run-Orangeburg	C	Sandy Run	Orangeburg	34.0	200-299	AC	956.0	2017
SERC-E	Orangeburg-St. George	C	Orangeburg	St. George	26.0	200-299	AC	956.0	2018
SERC-E	St. George-Varnville	C	St. George	Varnville	38.0	200-299	AC	956.0	2019
SERC-E	Bucksville-Garden City	P	Bucksville	Garden City	15.0	100-120	AC	797.0	2016
SERC-E	Proposed Watauga 230kV Sub-Boone	P	Proposed Watauga	Boone Step-Down Sub	2.0	100-120	AC	156.0	2019
SERC-E	Boone Step-Down Sub-Blowing Rock	UC	Boone Step-Down Sub	Blowing Rock Sub (None)	6.0	100-120	AC	92.0	2014
SERC-E	Blowing Rock Sub-New Blowing Rock	P	Blowing Rock Sub	New Blowing Rock Sub	1.0	100-120	AC	102.0	2014
SERC-E	Horse Gap Sub-New Watauga 230kV	P	Horse Gap Sub	New Watauga 230kV Sub	17.0	200-299	AC	402.0	2020
SERC-E	Hudson Sub-Oak Hill Sub	P	Hudson Sub	Oak Hill Sub	4.0	100-120	AC	156.0	2016
SERC-E	Beaver Creek Sub-United Chemi-Con	P	Beaver Creek Sub	United Chemi-Con Sub	8.0	100-120	AC	92.0	2015
SERC-E	Boone Step-Down Sub-Boone	P	Boone Step-Down Sub	Boone Step-Down Sub	9.0	100-120	AC	92.0	2016
SERC-E	Elizabeth 100 kV Lines	U	Kenilworth Ret	N Charlotte	0.0	100-120	AC	425.0	2015
SERC-E	Lyles-Denny Terrace	P	Lyles	Denny Terrace	3.0	200-299	AC	950.0	2015
SERC-E	Charlotte Street-Hagood Junction	P	Charlotte Street	Hagood Junction	5.0	100-120	AC	237.0	2012
SERC-E	Hagood-Accabee	P	Hagood	Accabee	1.0	100-120	AC	176.0	2012
SERC-E	Charlotte Street-Hagood Junction	R	Charlotte Street	Hagood Junction	0.0	100-120	AC	176.0	2012
SERC-E	Hagood-Faber Place	P	Hagood	Faber Place (2)	6.0	100-120	AC	237.0	2017

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SERC-E	Winyah-Bucksville	C	Winyah	Bucksville	32.0	200-299	AC	956.0	2015
SERC-E	Cross-Wassamassaw	C	Cross	Wassamassaw (2)	18.0	200-299	AC	956.0	2018
SERC-E	Bucksville-Conway	C	Bucksville	Conway	7.0	200-299	AC	956.0	2018
SERC-E	Red Bluff-Nixons Crossroads	C	Red Bluff	Nixons Crossroads (2)	14.0	100-120	AC	239.0	2019
SERC-E	Wassamassaw-St. George	C	Wassamassaw	St. George	22.0	200-299	AC	956.0	2019
SERC-E	Aiken Hampton-Aiken #3	U	Aiken Hampton	Aiken #3	0.0	100-120	AC	227.0	2014
SERC-E	Aiken Hampton-Aiken Transmission	U	Aiken Hampton	Aiken Transmission	0.0	100-120	AC	237.0	2015
SERC-E	Mt Pleasant-Bayview	U	Mt Pleasant	Bayview	0.0	100-120	AC	237.0	2014
SERC-E	Yemassee-Burton	U	Yemassee	Burton (2)	0.0	100-120	AC	352.0	2015
SERC-E	St Andrews-Queensboro	U	St Andrews	Queensboro	0.0	100-120	AC	237.0	2015
SERC-E	Cherokee 100 kV Lines	U	Cliffside Steam Station	1st Tap	0.0	100-120	AC	182.0	2013
SERC-E	Faber Place - Hagood Junction 115kV	U	Faber Place	Hagood Junction	0.0	100-120	AC	237.0	2017
SERC-E	Faber Place - Hagood Junction 115kV	U	Faber Place	Hagood Junction	0.0	100-120	AC	237.0	2017
SERC-E	Hagood - Bee Street 115kV Upgrade	U	Hagood	Bee Street	0.0	100-120	AC	352.0	2014
SERC-E	Faber Place - Hagood 115kV Upgrade	U	Faber Place	Hagood	0.0	100-120	AC	237.0	2014
SERC-E	Faber Place - Hagood 115kV #2	P	Faber Place	Hagood (2)	5.0	100-120	AC	237.0	2017
SERC-E	Hagood Junction - Hagood 115kV	P	Hagood Junction	Hagood	0.5	100-120	AC	237.0	2012
SERC-E	Hamlin-Isle of Palms 115kV Sub.Cable	UC	Hamlin	Isle of Palms	8.0	100-120	AC	237.0	2013
SERC-E	Lyles - Saluda River 115 kV	U	Lyles	Saluda River	0.0	100-120	AC	237.0	2015
SERC-E	Lake Murray - Saluda River 115 kV	U	Lake Murray	Saluda River	0.0	100-120	AC	237.0	2015
SERC-E	Raeford 230 kV	P	Richmond Co. Plant	Ft.Bragg Woodruff St Sub.	6.0	200-299	AC	1,195.0	2018
SERC-N	Apache Flats-Scruggs	P	Apache Flats	Scruggs	2.0	151-199	AC	286.0	2015
SERC-N	Rogersville-Holman	P	Rogersville	Holman	7.0	151-199	AC	286.0	2013
SERC-N	Willow Springs-Summersville East	P	Willow Springs	Summersville East	0.0	151-199	AC	203.0	2013
SERC-N	Summersville East-Sweetwater	P	Summersville East	Sweetwater	0.0	151-199	AC	203.0	2013
SERC-N	Mansfield-Mountain Grove	UC	Mansfield	Mountain Grove	22.0	151-199	AC	286.0	2012
SERC-N	Cabool-Mountain Grove	UC	Cabool	Mountain Grove	10.0	151-199	AC	286.0	2012
SERC-N	Cabool-Willow Springs	UC	Cabool	Willow Springs	14.0	151-199	AC	286.0	2012
SERC-N	Blackberry-Neosho	UC	Blackberry	Neosho	0.0	300-399	AC	870.0	2013
SERC-N	Blackberry-Morgan	UC	Blackberry	Morgan	0.0	300-399	AC	870.0	2013
SERC-N	Blackberry-Sportsman Acres	UC	Blackberry	Sportsman Acres	93.0	300-399	AC	1,369.0	2013
SERC-N	Cedar Crest-Locust Grove	P	Cedar Crest	Locust Grove	0.0	151-199	AC	204.0	2012
SERC-N	Cedar Crest-Talequah	P	Cedar Crest	Talequah	0.0	151-199	AC	204.0	2012
SERC-N	Cedar Crest-Lowery	P	Cedar Crest	Lowery	12.0	151-199	AC	204.0	2012
SERC-N	Cedar Crest-Lowery	P	Cedar Crest	Lowery	12.0	151-199	AC	286.0	2012
SERC-N	Cedar Crest-Peggs	P	Cedar Crest	Peggs	4.0	151-199	AC	286.0	2012
SERC-N	Bristow-Okemah	UC	Bristow	Okemah	0.0	121-150	AC	174.0	2013
SERC-N	Pharoah-Okemah	UC	Pharoah	Okemah	0.0	121-150	AC	174.0	2013
SERC-N	Gypsy-Stroud	P	Gypsy	Stroud	21.1	121-150	AC	122.0	2014
SERC-N	Stroud-Warwick	P	Stroud	Warwick	12.0	121-150	AC	245.0	2014
SERC-N	Wheaton-Cassville	P	Wheaton	Cassville	15.0	151-199	AC	286.0	2015
SERC-N	Maries-Dixon	P	Maries	Dixon	5.0	151-199	AC	286.0	2018
SERC-N	Enon-Lake St. Louis	P	Enon	Lake St. Louis	5.0	151-199	AC	372.0	2014
SERC-N	Lake St Louis-Dardenne	P	Lake St Louis	Dardenne	3.0	151-199	AC	372.0	2014
SERC-N	Rolla (South)-Yancy Mills	P	Rolla (South)	Yancy Mills	7.0	100-120	AC	122.0	2012
SERC-N	Luther-Warwick Tap	P	Luther	Warwick Tap	7.4	121-150	AC	245.0	2013
SERC-N	Davidson-Pin Hook	U	Davidson	Pin Hook	0.0	400-599	AC	2,598.0	2013
SERC-N	Shelby-Lagoon Creek	U	Shelby	Lagoon Creek	0.0	400-599	AC	2,598.0	2012
SERC-N	Wilson-Pin Hook	U	Wilson	Pin Hook	0.0	400-599	AC	2,598.0	2013
SERC-N	Widows Creek-Oglethorpe	U	Widows Creek	Oglethorpe (2)	0.0	151-199	AC	299.0	2012
SERC-N	Widows Creek-Oglethorpe	U	Widows Creek	Oglethorpe (3)	0.0	151-199	AC	299.0	2012
SERC-N	Volunteer-East Knox	UC	Volunteer	East Knox	13.0	151-199	AC	450.0	2015
SERC-N	Gallatin-Angeltown	UC	Gallatin	Angeltown	19.0	151-199	AC	410.0	2012
SERC-N	Choctaw-French Camp	U	Choctaw	French Camp	0.0	400-599	AC	2,598.0	2015
SERC-N	Unionville-Rally Hill	UC	Unionville	Rally Hill	18.0	151-199	AC	299.0	2012
SERC-N	West Point-Clay	UC	West Point	Clay	0.0	400-599	AC	2,598.0	2012
SERC-N	MEC-Nucor	P	MEC	Nucor	2.0	151-199	AC	371.0	2015
SERC-N	Wolf Creek-Clinton County 161 kV	C	Wolf Creek	Clinton County	9.0	151-199	AC	292.0	2019
SERC-N	Grahamville-Joppa DOE C33	P	Grahamville	Joppa DOE C33 (2)	2.0	151-199	AC	346.0	2012
SERC-N	Hardin County-Elizabethtown	P	Hardin County	Elizabethtown (2)	1.0	121-150	AC	296.0	2014
SERC-N	Paddys West-Speed 345kV	C	Paddys West	Speed	11.0	300-399	AC	1,195.0	2012
SERC-N	2nd Grahamville-Wickliffe kV	C	Grahamville	Wickliffe (2)	20.0	151-199	AC	889.0	2017
SERC-N	Shelby-Cordova	UC	Shelby	Cordova (2)	23.0	400-599	AC	1,732.0	2012
SERC-N	Sub. 79-Sub. 86	UC	Sub. 79	Sub. 86	11.0	151-199	AC	421.0	2013
SERC-N	Airport-South	U	Airport	South	0.0	151-199	AC	532.0	2022
SERC-N	Airport-Murfreesboro Road	U	Airport	Murfreesboro Road	0.0	151-199	AC	532.0	2022
SERC-N	Battlefield-Craighead	P	Battlefield	Craighead	1.0	151-199	AC	532.0	2016

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SERC-N	Battlefield-Sharondale	P	Battlefield	Sharondale	3.0	151-199	AC	532.0	2016
SERC-N	Elza-Huntsville	U	Elza	Huntsville	0.0	151-199	AC	237.0	2012
SERC-N	Wheeler-Mt. Pleasant	U	Wheeler	Mt. Pleasant	0.0	151-199	AC	334.0	2012
SERC-N	Rebuild / Reconductor Line	UC	Farley	Guntersville	17.0	151-199	AC	367.0	2012
SERC-N	Marshall-Calvert	U	Marshall	Calvert	0.0	151-199	AC	697.0	2013
SERC-N	Marshall-Calvert	U	Marshall	Calvert (2)	0.0	151-199	AC	697.0	2013
SERC-N	Madison-Farley	U	Madison	Farley	0.0	121-150	AC	410.0	2012
SERC-N	ServerCorr-Clayton Village	UC	ServerCorr	Clayton Village	14.0	151-199	AC	423.0	2013
SERC-N	East Point-Arab	U	East Point	Arab	0.0	151-199	AC	318.0	2013
SERC-N	Johnsonville FP-Monsanto	U	Johnsonville FP	Monsanto	0.0	151-199	AC	208.0	2013
SERC-N	Marshall-C33	U	Marshall	C33	0.0	151-199	AC	237.0	2014
SERC-N	Ardmore-Park City	U	Ardmore	Fayetteville	0.0	151-199	AC	232.0	2014
SERC-N	Decatur-Priceville	U	Decatur	Guntersville	0.0	151-199	AC	334.0	2013
SERC-N	Guntersville-Goose Pond	U	Guntersville	Goose Pond	0.0	151-199	AC	334.0	2012
SERC-N	Calvert-South Calvert	U	Calvert	South Calvert (2)	0.0	151-199	AC	237.0	2012
SERC-N	Marshall-Benton	U	Marshall	Benton	0.0	151-199	AC	307.0	2013
SERC-N	Marshall-Mayfield	U	Marshall	Mayfield	0.0	151-199	AC	410.0	2014
SERC-N	Fayette-South Jessamine 138 kV Line	C	Fayette	South Jessamine	7.3	121-150	AC	267.0	2019
SERC-N	W. Berea-Three Links Junction 138 kV	P	West Berea	Three Links Junction	7.5	121-150	AC	267.0	2020
SERC-N	Starkville-Clayton Village	P	Starkville	Clayton Village	4.6	151-199	AC	371.0	2013
SERC-N	Matanzas	P	Matanzas	Ohio Co	0.0	121-150	AC	210.0	2013
SERC-N	Matanzas	P	Matanzas	Green River	0.0	121-150	AC	210.0	2013
SERC-N	New Albany 345kV	P	New Albany	Paddys West	0.3	300-399	AC	1,146.0	2013
SERC-N	New Albany 345kV	P	New Albany	Northside	0.3	300-399	AC	1,146.0	2013
SERC-N	Midway 138kV	C	Midway	Adams	0.0	121-150	AC	166.0	2015
SERC-N	Midway 138kV	C	Midway	Tyrone	0.0	121-150	AC	166.0	2015
SERC-N	Baldor-Westville	P	Baldor	Westville	4.0	151-199	AC	122.0	2012
SERC-N	Holman-Crossway	P	Holman	Crossway	9.0	151-199	AC	286.0	2012
SERC-N	Franks-Barnett	P	Franks	Barnett	50.0	300-399	AC	1,369.0	2016
SERC-N	Turkey Creek-Warsaw East	P	Turkey Creek	Warsaw East	7.0	151-199	AC	286.0	2014
SERC-N	March-Crossway	P	March	Crossway	12.0	151-199	AC	122.0	2013
SERC-N	St. Francis-St. Francis Tap	P	St. Francis	St. Francis Tap	4.3	300-399	AC	870.0	2013
SERC-N	Fredericktown-Lutesville	P	Fredericktown	Lutesville	16.2	151-199	AC	122.0	2014
SERC-N	Jasper-Lamar	P	Jasper	Lamar	13.0	151-199	AC	319.0	2012
SERC-N	Kingdom City-Mexico North	P	Kingdom City	Mexico North	20.0	151-199	AC	286.0	2015
SERC-N	Enon-Enon Tap	P	Enon	Enon Tap	0.3	300-399	AC	1,382.0	2016
SERC-N	Maries-Rolla North Wye	P	Maries	Rolla North Wye	20.8	151-199	AC	286.0	2014
SERC-N	Oak Ridge-Eufala	C	Oak Ridge	Eufala	10.0	121-150	AC	245.0	2015
SERC-N	Stillwell-Baldor	P	Stillwell	Baldor	15.3	151-199	AC	122.0	2012
SERC-N	Carthage-Philbert	C	Carthage	Philbert	3.5	151-199	AC	286.0	2019
SERC-N	Jasper-Philbert	C	Jasper	Philbert	16.7	151-199	AC	286.0	2019
SERC-N	Sedalia-Windsor Tap	P	Sedalia	Windsor Tap	1.0	151-199	AC	286.0	2013
SERC-N	Barnett-Eldon	P	Barnett	Eldon	0.0	151-199	AC	204.0	2016
SERC-N	Warwick Tap-Warwick	P	Warwick Tap	Warwick	7.4	121-150	AC	228.0	2013
SERC-N	Notch-Redwood	P	Notch	Redwood	30.0	151-199	AC	286.0	2013
SERC-SE	Barry-Chickasaw	U	Barry	Chickasaw	0.0	200-299	AC	1,243.0	2015
SERC-SE	Gaston-East Pelham	U	Gaston	East Pelham	0.0	200-299	AC	502.0	2022
SERC-SE	North Crichton S.S.-South Mobile	U	North Crichton S.S.	South Mobile	0.0	100-120	AC	184.0	2014
SERC-SE	North Crichton S.S.-South Mobile	U	North Crichton S.S.	South Mobile (2)	0.0	100-120	AC	184.0	2014
SERC-SE	Big Creek T.S.-Lynndell D.S.	P	Big Creek T.S.	Lynndell D.S.	8.0	100-120	AC	290.0	2014
SERC-SE	North Mobile-Crichton #1	U	North Mobile	Crichton #1	0.0	100-120	AC	290.0	2015
SERC-SE	Schillinger Road-Lott Road Tap	P	Schillinger Road	Lott Road Tap	2.0	100-120	AC	290.0	2014
SERC-SE	Leeds-Westbury	U	Leeds	Westbury	0.0	100-120	AC	270.0	2018
SERC-SE	North Brewton TS-North Brewton DS	P	North Brewton TS	North Brewton DS	6.0	100-120	AC	290.0	2020
SERC-SE	Wire Road-Wire Road Tap	P	Wire Road	Wire Road Tap	4.0	100-120	AC	216.0	2021
SERC-SE	Opelika #1-Opelika #3	U	Opelika #1	Opelika #3	0.0	100-120	AC	138.0	2021
SERC-SE	North Mobile-Racetrack D.S.	P	North Mobile	Racetrack D.S.	2.0	100-120	AC	290.0	2014
SERC-SE	Old Pascagoula Tap-Old Pascagoula	P	Old Pascagoula Tap	Old Pascagoula Rd	2.0	100-120	AC	138.0	2012
SERC-SE	Kimberly Clark-Blakeley Island	U	Kimberly Clark	Blakeley Island	0.0	100-120	AC	341.0	2019
SERC-SE	McIntosh-Jackson TS (New miles)	P	McIntosh	Jackson TS (New miles)	2.0	100-120	AC	216.0	2013
SERC-SE	Springdale D.S.-Springhill D.S.	U	Springdale D.S.	Springhill D.S.	0.0	100-120	AC	216.0	2016
SERC-SE	Michael Blvd D.S.-Michael Blvd Tap	U	Michael Blvd D.S.	Michael Blvd Tap	0.0	100-120	AC	138.0	2015
SERC-SE	Wolf Ridge D.S. Tap-Springhill D.S.	U	Wolf Ridge D.S. Tap	Springhill D.S.	0.0	100-120	AC	216.0	2015
SERC-SE	Barnwell Tap-Barnwell	U	Barnwell Tap	Barnwell	0.0	100-120	AC	216.0	2012
SERC-SE	Racetrack D.S.-Lott Road	P	Racetrack D.S.	Lott Road	4.0	100-120	AC	290.0	2014
SERC-SE	Anniston Tap-Golden Springs	U	Anniston Tap	Golden Springs	0.0	100-120	AC	216.0	2012
SERC-SE	Henry Dam-Cedar Bend	U	Henry Dam	Cedar Bend	0.0	100-120	AC	159.0	2015

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SERC-SE	So. Tuscaloosa-Holt	U	So. Tuscaloosa	Holt	0.0	100-120	AC	341.0	2016
SERC-SE	Anniston-Oxanna	U	Anniston	Oxanna	0.0	100-120	AC	216.0	2014
SERC-SE	Anniston-Greenbrier	P	Anniston	Greenbrier	1.0	100-120	AC	216.0	2014
SERC-SE	31st Avenue-South Tuscaloosa	U	31st Avenue	South Tuscaloosa	0.0	100-120	AC	341.0	2015
SERC-SE	Demopolis-Selma	U	Demopolis	Selma	0.0	100-120	AC	216.0	2019
SERC-SE	Barnwell Tap-Turkey Hill	P	Barnwell Tap	Turkey Hill	3.0	100-120	AC	216.0	2018
SERC-SE	Silverhill-Fish River Tap	U	Silverhill	Fish River Tap	0.0	100-120	AC	216.0	2018
SERC-SE	Plantation Pipeline (Akron)-Akron	P	Plantation Pipeline	Akron	1.0	100-120	AC	383.0	2014
SERC-SE	Colonial Pipeline Tap-Colonial	U	Colonial Pipeline Tap	Colonial Pipeline	0.0	100-120	AC	138.0	2019
SERC-SE	Pinckard TS-Slocomb TS	U	Pinckard TS	Slocomb TS	0.0	100-120	AC	336.0	2013
SERC-SE	North Selma-Inter Paper Tap	P	North Selma	Inter Paper Tap	7.0	100-120	AC	216.0	2014
SERC-SE	Slocomb TS-AL/FL State Line	U	Slocomb TS	AL/FL State Line	0.0	100-120	AC	336.0	2014
SERC-SE	Snowdoun TS-Pike Co	U	Snowdoun TS	Pike Co	0.0	200-299	AC	807.0	2014
SERC-SE	Autaugaville 6-Autaugaville 8	P	Autaugaville 6	Autaugaville 8	1.0	200-299	AC	1,614.0	2013
SERC-SE	South Montg-Pinedale	U	South Montg	Pinedale	0.0	100-120	AC	216.0	2013
SERC-SE	Pinedale-ECI Halstead	U	Pinedale	ECI Halstead	0.0	100-120	AC	216.0	2013
SERC-SE	Montg SS-South Montg	U	Montg SS	South Montg	0.0	200-299	AC	403.0	2013
SERC-SE	Cedar Bend-North Cedar Bend Tap	U	Cedar Bend	North Cedar Bend Tap	0.0	100-120	AC	138.0	2015
SERC-SE	Bynum-Anniston	U	Bynum	Anniston	0.0	100-120	AC	454.0	2014
SERC-SE	Tap 115kV TL from Fayette Highway	P	Fayette HW-Hunt Oil	Airport DS	2.0	100-120	AC	216.0	2017
SERC-SE	Bellamy SS-Cuba	U	Bellamy SS	Cuba	0.0	100-120	AC	154.0	2021
SERC-SE	Demopolis TS-Cemex	U	Demopolis TS	Cemex	0.0	100-120	AC	154.0	2021
SERC-SE	Big Sandy Tap-Englewood Tap	U	Big Sandy Tap	Englewood Tap	0.0	100-120	AC	138.0	2016
SERC-SE	Moundville-North Moundville	P	Moundville	North Moundville	5.0	100-120	AC	383.0	2015
SERC-SE	Englewood Tap-Moundville	P	Englewood Tap	Moundville	9.0	100-120	AC	383.0	2014
SERC-SE	Englewood Tap-South Tuscaloosa	P	Englewood Tap	South Tuscaloosa	18.0	100-120	AC	383.0	2016
SERC-SE	Moundville-Colonial Pipeline	P	Moundville	Colonial Pipeline	6.0	100-120	AC	383.0	2019
SERC-SE	Epes-Eutaw	P	Epes	Eutaw	23.0	100-120	AC	341.0	2014
SERC-SE	O'Hara-McDonough Primary	P	O'Hara	McDonough Primary	20.0	200-299	AC	602.0	2018
SERC-SE	South Dahlonega-Palmer Creek	P	South Dahlonega	Palmer Creek	10.0	200-299	AC	602.0	2019
SERC-SE	Vogtle-Thomson	P	Vogtle	Thomson	60.0	400-599	AC	2,701.0	2016
SERC-SE	Kraft-McIntosh (white)	U	Kraft	McIntosh (white)	0.0	200-299	AC	1,024.0	2012
SERC-SE	Blanford/Meldrim-McIntosh (white)	U	Blanford/Meldrim	McIntosh (white)	0.0	200-299	AC	1,024.0	2014
SERC-SE	Blanford/Meldrim-McIntosh (black)	U	Blanford/Meldrim	McIntosh (black) (2)	0.0	200-299	AC	1,024.0	2014
SERC-SE	Austin Drive-River Road	U	Austin Drive	River Road	0.0	100-120	AC	216.0	2016
SERC-SE	Bark Camp-Gainesville #1	U	Bark Camp	Gainesville #1	0.0	100-120	AC	216.0	2013
SERC-SE	Bremen-Possum Branch	U	Bremen	Possum Branch	0.0	100-120	AC	255.0	2019
SERC-SE	Brunswick-Stonewall Junct.	U	Brunswick	Stonewall Junct.	0.0	100-120	AC	216.0	2018
SERC-SE	Cornish Mountain-Sigman Road	U	Cornish Mountain	Sigman Road	0.0	100-120	AC	301.0	2018
SERC-SE	Daniel Siding-Little Ogeechee	U	Daniel Siding	Little Ogeechee	0.0	100-120	AC	369.0	2017
SERC-SE	Dawsonville-Leach Road	U	Dawsonville	Leach Road	0.0	100-120	AC	216.0	2013
SERC-SE	Decatur-Kirkland	U	Decatur	Kirkland	0.0	100-120	AC	188.0	2016
SERC-SE	Douglasville-Post Road	U	Douglasville	Post Road	0.0	100-120	AC	140.0	2016
SERC-SE	Douglasville-West Marietta	U	Douglasville	West Marietta	0.0	100-120	AC	255.0	2021
SERC-SE	East Social Circle-Social Circle	U	East Social Circle	Social Circle	0.0	100-120	AC	255.0	2020
SERC-SE	Hampton-McDonough Pri	U	Hampton	McDonough Pri	0.0	100-120	AC	301.0	2015
SERC-SE	Horse Creek-Ludowici	U	Horse Creek	Ludowici	0.0	100-120	AC	216.0	2017
SERC-SE	Jack McDonough-Northwest	U	Jack McDonough	Northwest	0.0	200-299	AC	602.0	2013
SERC-SE	Jack McDonough-Northwest	U	Jack McDonough	Northwest (2)	0.0	200-299	AC	602.0	2013
SERC-SE	Jack McDonough-West Marietta	P	Jack McDonough	West Marietta	4.0	100-120	AC	255.0	2018
SERC-SE	Jesup-Rayonier	U	Jesup	Rayonier	0.0	100-120	AC	216.0	2017
SERC-SE	McConnell Road-South Acworth	U	McConnell Road	South Acworth	0.0	100-120	AC	301.0	2021
SERC-SE	O'Hara-Corinth Road	U	O'Hara	Corinth Road	0.0	100-120	AC	255.0	2021
SERC-SE	Porterdale-S. Covington Tap	U	Porterdale	S. Covington Tap	0.0	100-120	AC	138.0	2013
SERC-SE	South Griffin-Jackson	U	South Griffin	Jackson	0.0	100-120	AC	216.0	2013
SERC-SE	W. Brunswick-Altamaha	P	W. Brunswick	Altamaha	8.0	100-120	AC	216.0	2016
SERC-SE	East Point-College Park #3	U	East Point	College Park #3	0.0	100-120	AC	255.0	2017
SERC-SE	Mountain View-Barnett Road	U	Mountain View	Barnett Road	0.0	100-120	AC	255.0	2021
SERC-SE	Morrow-Ellenwood	U	Morrow	Ellenwood	0.0	100-120	AC	417.0	2016
SERC-SE	Parkaire-Roswell	P	Parkaire	Roswell	5.0	100-120	AC	301.0	2018
SERC-SE	Berkeley Lake-Spruill Road	U	Berkeley Lake	Spruill Road	0.0	200-299	AC	682.0	2018
SERC-SE	Grady-Moreland Avenue	U	Grady	Moreland Avenue	0.0	100-120	AC	293.0	2012
SERC-SE	Northside Drive-Northwest	U	Northside Drive	Northwest	0.0	100-120	AC	301.0	2013
SERC-SE	Atkinson-Northside Drive	U	Atkinson	Northside Drive	0.0	100-120	AC	188.0	2013
SERC-SE	Northside Drive-Spring Street	U	Northside Drive	Spring Street	0.0	100-120	AC	269.0	2013
SERC-SE	North Americus-North Tifton	U	North Americus	North Tifton	0.0	100-120	AC	124.0	2014
SERC-SE	First Avenue-North Columbs	U	First Avenue	North Columbs	0.0	100-120	AC	216.0	2021

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SERC-SE	Bull Creek-Victory Drive	U	Bull Creek	Victory Drive	0.0	100-120	AC	216.0	2015
SERC-SE	Americus-North Americus	U	Americus	North Americus	0.0	100-120	AC	155.0	2021
SERC-SE	Blackshear Jct.-Offerman	U	Blackshear Jct.	Offerman	0.0	100-120	AC	216.0	2019
SERC-SE	Bemiss-Pine Grove Primary	U	Bemiss	Pine Grove Primary	0.0	100-120	AC	216.0	2021
SERC-SE	Lassiter Road-North Marietta	U	Lassiter Road	North Marietta	0.0	100-120	AC	341.0	2013
SERC-SE	Dean Forest-Kraft	U	Dean Forest	Kraft	0.0	200-299	AC	866.0	2015
SERC-SE	Dean Forest-GSW	P	Dean Forest	GSW	5.0	200-299	AC	1,018.0	2015
SERC-SE	Boulevard-Dean Forest	U	Boulevard	Dean Forest	0.0	100-120	AC	433.0	2015
SERC-SE	Boulevard-Dean Forest	U	Boulevard	Dean Forest (2)	0.0	200-299	AC	866.0	2015
SERC-SE	Dorchester-Little Ogeechee	U	Dorchester	Little Ogeechee	0.0	200-299	AC	1,205.0	2017
SERC-SE	Dorchester-West Brunswick	P	Dorchester	West Brunswick	45.0	200-299	AC	1,018.0	2017
SERC-SE	Dorchester-Walthoursville	P	Dorchester	Walthoursville	8.0	100-120	AC	216.0	2017
SERC-SE	Sylvania-Deal Branch	U	Sylvania	Deal Branch	0.0	100-120	AC	124.0	2019
SERC-SE	Bethabara-East Walton	P	Bethabara	East Walton	8.0	200-299	AC	602.0	2017
SERC-SE	Bostwick-East Walton	P	Bostwick	East Walton	4.0	200-299	AC	602.0	2017
SERC-SE	East Walton-Jack's Creek	P	East Walton	Jack's Creek	9.0	200-299	AC	602.0	2017
SERC-SE	East Walton-Rockville	P	East Walton	Rockville	40.0	400-599	AC	3,464.0	2017
SERC-SE	Cumming-Sharon Springs	P	Cumming	Sharon Springs	7.0	200-299	AC	602.0	2018
SERC-SE	Burnt Church-Tradeport Industrial	UC	Burnt Church	Tradeport Industrial	12.0	100-120	AC	216.0	2013
SERC-SE	Daniel Siding-Burnt Church	U	Daniel Siding	Burnt Church	0.0	100-120	AC	216.0	2016
SERC-SE	Lords-Toomsboro	P	Lords	Toomsboro	4.0	100-120	AC	124.0	2014
SERC-SE	Ingram-Peeksville	P	Ingram	Peeksville	7.0	100-120	AC	216.0	2018
SERC-SE	Barry-Crist	U	Barry	Crist	0.0	200-299	AC	693.0	2015
SERC-SE	Lansing Smith-Laguna Beach	P	Lansing Smith	Laguna Beach	14.0	200-299	AC	602.0	2013
SERC-SE	Laguna Beach-Santa Rosa	P	Laguna Beach	Santa Rosa	21.0	200-299	AC	602.0	2015
SERC-SE	Lansing Smith-Laguna Beach	U	Lansing Smith	Laguna Beach	0.0	100-120	AC	301.0	2012
SERC-SE	Champion-Molino	U	Champion	Molino	0.0	100-120	AC	251.0	2012
SERC-SE	Callaway-Gaskin	U	Callaway	Gaskin	0.0	100-120	AC	216.0	2022
SERC-SE	Pine Forest-Champion	U	Pine Forest	Champion	0.0	100-120	AC	251.0	2012
SERC-SE	Pinckard-Holmes Creek	U	Pinckard	Holmes Creek	0.0	100-120	AC	336.0	2013
SERC-SE	Laguna Beach-Santa Rosa	P	Laguna Beach	Santa Rosa (2)	21.0	200-299	AC	602.0	2015
SERC-SE	Bayou Marcus-Beach Haven	U	Bayou Marcus	Beach Haven	0.0	100-120	AC	124.0	2018
SERC-SE	Wright-Sullivan	U	Wright	Sullivan	0.0	100-120	AC	251.0	2022
SERC-SE	Wright-Fort Walton	U	Wright	Fort Walton	0.0	100-120	AC	251.0	2022
SERC-SE	Wiggins SS-Wiggins 5th Ave	U	Wiggins SS	Wiggins 5th Ave	0.0	100-120	AC	216.0	2017
SERC-SE	Hattiesburg SW-Hwy 11	U	Hattiesburg SW	Hwy 11	0.0	100-120	AC	216.0	2014
SERC-SE	Hattiesburg SW-West Hattiesburg	U	Hattiesburg SW	West Hattiesburg	0.0	100-120	AC	216.0	2014
SERC-SE	Orange Grove-Chevron PRCP	P	Orange Grove	Chevron PRCP	5.0	100-120	AC	251.0	2022
SERC-SE	Orange Grove-Bayou Casotte	U	Orange Grove	Bayou Casotte	0.0	100-120	AC	251.0	2022
SERC-SE	Kemper IGCC-Lauderdale East	UC	Kemper IGCC	Lauderdale East	18.0	200-299	AC	752.0	2012
SERC-SE	Kemper IGCC-Lauderdale West	UC	Kemper IGCC	Lauderdale West	20.0	200-299	AC	752.0	2013
SERC-SE	Lauderdale East-Vimville	UC	Lauderdale East	Vimville	6.0	200-299	AC	602.0	2013
SERC-SE	Vimville-Sweatt	UC	Vimville	Sweatt	14.0	200-299	AC	602.0	2013
SERC-SE	Sweatt-Stonewall	U	Sweatt	Stonewall	0.0	100-120	AC	216.0	2012
SERC-SE	Meridian NE-Vimville	UC	Meridian NE	Vimville	9.0	100-120	AC	216.0	2014
SERC-SE	Hurricane Creek-Wiggins SS	U	Hurricane Creek	Wiggins SS	0.0	100-120	AC	216.0	2016
SERC-SE	Laurel North Amaranth-Heidelberg	U	Laurel North Amaranth	Heidelberg	0.0	100-120	AC	216.0	2014
SERC-SE	Plant Daniel-Moss Point East	U	Plant Daniel	Moss Point East	0.0	200-299	AC	865.0	2012
SERC-SE	Orange Grove-Moss Point East	U	Orange Grove	Moss Point East	0.0	200-299	AC	752.0	2022
SERC-SE	Hattiesburg North-Petal George St.	U	Hattiesburg North	Petal George St.	0.0	100-120	AC	155.0	2014
SERC-SE	Goshen-Waynesboro	U	Goshen	Waynesboro	0.0	100-120	AC	255.0	2016
SERC-SE	North Marietta-Marietta #5	U	North Marietta	Marietta #5	0.0	100-120	AC	325.0	2013
SERC-SE	Crisp #2-Crisp #8	C	Crisp #2	Crisp #8	12.0	100-120	AC	216.0	2014
SERC-SE	Bonaire Primary-Fort Valley 115kV	U	Bonaire Primary	Peach Blossum	0.0	100-120	AC	216.0	2017
SERC-SE	Prentiss-Jeff Davis SS	UC	Prentiss	Jeff Davis SS	7.0	151-199	AC	296.0	2012
SERC-SE	Moselle-South Hoy	P	Moselle	South Hoy	23.0	151-199	AC	296.0	2013
SERC-SE	Miflin Switch-Josephine TP	P	Miflin Switch	Josephine TP	5.0	100-120	AC	300.0	2013
SERC-SE	Texasville Jct-Judson	UC	Texasville Jct	Judson	16.0	100-120	AC	210.0	2012
SERC-SE	Selma Jct-Selma	P	Selma Jct	Selma	1.0	100-120	AC	86.0	2012
SERC-SE	Wayne Farms Jct-Wayne Farms	C	Wayne Farms Jct	Wayne Farms	4.0	100-120	AC	86.0	2012
SERC-SE	Owls Head Jct-Owls Head	C	Owls Head Jct	Owls Head	2.0	100-120	AC	86.0	2012
SERC-SE	Gulf Coast Airport Jct-Gulf Coast	P	Gulf Coast Airport Jct	Gulf Coast Airport	1.0	100-120	AC	86.0	2012
SERC-SE	APAC Jct-APAC	C	APAC Jct	APAC	1.0	100-120	AC	86.0	2012
SERC-SE	Millers Crossroad Jct-Millers	C	Millers Crossroad Jct	Millers Crossroad	1.0	100-120	AC	86.0	2012
SERC-SE	Freeport 230-Freeport 115	C	Freeport 230	Freeport 115	1.0	200-299	AC	586.0	2013
SERC-SE	Oak Grove-Jay	P	Oak Grove	Jay	24.0	100-120	AC	218.0	2013
SERC-SE	Gantt 230-Dublin	C	Gantt 230	Dublin	37.0	100-120	AC	218.0	2013

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SERC-SE	Josephine TP-Florida Ave	P	Josephine TP	Florida Ave	1.0	100-120	AC	300.0	2013
SERC-SE	East Point - Willingham Dr. 115kV	U	East Point	Willingham	0.0	100-120	AC	255.0	2017
SERC-SE	McConnell Road-South Acworth	U	McConnell Road	South Acworth	0.0	100-120	AC	301.0	2020
SERC-SE	Dresden-Heard County	UC	Dresden	Heard County	6.0	400-599	AC	3,429.0	2014
SERC-SE	Barry-North Mobile	U	Barry	North Mobile (2)	0.0	100-120	AC	301.0	2016
SERC-SE	Fish River Tap-Fairhope	U	Fish River Tap	Fairhope	0.0	100-120	AC	216.0	2018
SERC-SE	Fairhope-Point Clear	U	Fairhope	Point Clear	0.0	100-120	AC	216.0	2018
SERC-SE	Ellicott TS-SSAB	P	Ellicott TS	SSAB	6.0	200-299	AC	807.0	2021
SERC-SE	SSAB-Kushla S.S.	U	SSAB	Kushla S.S.	0.0	200-299	AC	693.0	2021
SERC-SE	Ellicott TS-Georgetown D.S.	U	Ellicott TS	Georgetown D.S.	0.0	200-299	AC	693.0	2021
SERC-SE	Co line Rd-PSDF	U	Co line Rd	PSDF	0.0	200-299	AC	907.0	2019
SERC-SE	McIntosh-Yemassee	U	McIntosh	Yemassee (10)	0.0	100-120	AC	286.0	2019
SERC-SE	Vogtle-Wilson	U	Vogtle	Wilson	0.0	200-299	AC	1,018.0	2019
SERC-SE	Waynesboro-Wilson	U	Waynesboro	Wilson	0.0	200-299	AC	866.0	2020
SERC-SE	Wadley-Waynesboro	U	Wadley	Waynesboro	0.0	200-299	AC	718.0	2019
SERC-SE	East Point-Willingham Drive	U	East Point	Willingham Drive	0.0	100-120	AC	255.0	2017
SERC-SE	S. Columbus-Dawson Pri/Ft.Ben,AL	U	South Columbus	Dawson Pri/Ft. Ben, AL	0.0	100-120	AC	124.0	2015
SERC-SE	American Cyanamid-Avalon	P	American Cyanamid	Avalon	4.0	100-120	AC	251.0	2018
SERC-SE	Crist-Escambia Chemical Tap	U	Crist	Escambia Chemical Tap	0.0	100-120	AC	251.0	2013
SERC-SE	Escambia Chemical Tap-Air Products	U	Escambia Chemical Tap	Air Products	0.0	100-120	AC	251.0	2013
SERC-SE	Escambia Chemical Tap-American Cy	U	Escambia Chemical Tap	American Cyanamid	0.0	100-120	AC	251.0	2013
SERC-SE	Greenwood-Highland City	U	Greenwood	Highland City	0.0	100-120	AC	301.0	2022
SERC-SE	Highland City-Callaway	P	Highland City	Callaway	4.0	200-299	AC	602.0	2013
SERC-SE	Gaston-Yellowdirt	U	Gaston	Yellowdirt	0.0	200-299	AC	602.0	2012
SERC-SE	Bonaire-Waterford	U	Bonaire	Waterford	0.0	100-120	AC	216.0	2013
SERC-SE	Gaston-Roopville	U	Gaston	Roopville (2)	0.0	200-299	AC	602.0	2012
SERC-SE	Autaugaville 6-Autuagaville 8	P	Autaugaville 6	Autuagaville 8 (2)	1.0	200-299	AC	1,614.0	2013
SERC-SE	Enterprise-South Enterprise TS	P	Enterprise	South Enterprise TS	5.0	100-120	AC	216.0	2015
SERC-SE	Co Line Rd-ECI Prattville	P	Co Line Rd	ECI Prattville	7.0	100-120	AC	216.0	2021
SERC-SE	GKN Wesland-Hall Climate Tap	U	GKN Wesland	Hall Climate Tap	0.0	100-120	AC	216.0	2019
SERC-SE	Meridian NE-Hawkins Crossing	U	Meridian NE	Hawkins Crossing	0.0	100-120	AC	216.0	2012
SERC-SE	McManus-West Brunswick	U	McManus	West Brunswick	0.0	100-120	AC	301.0	2014
SERC-SE	Arnold Mill-Hopewell	P	Arnold Mill	Hopewell	12.0	200-299	AC	509.0	2021
SERC-SE	Highway 54 - Ebenezer Road	P	Highway 54	Ebenezer Road	6.0	100-120	AC	255.0	2019
SERC-SE	Highway 54-Tyrone	P	Highway 54	Tyrone	6.0	100-120	AC	255.0	2019
SERC-SE	Golden Springs-Cheaha Tap	U	Golden Springs	Cheaha Tap	0.0	100-120	AC	216.0	2017
SERC-SE	North Cedar Bend Tap-Rainbow City	U	North Cedar Bend Tap	Rainbow City	0.0	100-120	AC	159.0	2015
SERC-SE	Barnwell-Point Clear	U	Barnwell	Point Clear	0.0	100-120	AC	216.0	2014
SERC-SE	North Brewton TS-Crist S.P.	P	North Brewton TS	Crist S.P.	56.0	200-299	AC	907.0	2021
SERC-SE	Gorgas-Jaspter TS Tap	U	Gorgas	Jaspter TS Tap	0.0	151-199	AC	303.0	2017
SERC-SE	Jasper TS-Jasper SS	P	Jasper TS	Jasper SS	1.0	151-199	AC	303.0	2017
SERC-SE	Jasper TS-Parkland SS	U	Jasper TS	Parkland SS	0.0	151-199	AC	303.0	2017
SERC-SE	PSDF-County Line Rd	U	PSDF	County Line Rd	0.0	200-299	AC	577.0	2015
SERC-SE	PSDF-Gaston	U	PSDF	Gaston	0.0	200-299	AC	907.0	2019
SERC-SE	Greene County-North Selma	U	Greene County	North Selma	0.0	200-299	AC	907.0	2020
SERC-SE	Greenwood-Shipyard	U	Greenwood	Shipyard	0.0	100-120	AC	289.0	2021
SERC-SE	Marianna-Highland City	U	Marianna	Highland City	0.0	100-120	AC	251.0	2013
SERC-SE	Milligan Tap-Milligan	P	Milligan Tap	Milligan	1.0	100-120	AC	155.0	2012
SERC-SE	Sinai Cemetery-Woodruff Tap	U	Sinai Cemetery	Woodruff Tap	0.0	100-120	AC	320.0	2015
SERC-SE	South Crestview-Airport	P	South Crestview	Airport	5.0	100-120	AC	155.0	2013
SERC-SE	North Brewton-Crist SP	P	North Brewton	Crist SP	56.0	200-299	AC	907.0	2021
SERC-SE	Cairo #1 to Brumbley Creek	C	Cairo # 1	Brumbley Creek	4.1	100-120	AC	124.0	2013
SERC-SE	Elberton #1 to Elberton #2	C	Elberton #1	Elberton #2	2.6	100-120	AC	124.0	2014
SERC-SE	Griffin #1 to Griffin #2	C	Griffin #1	Griffin #2	1.6	100-120	AC	124.0	2014
SERC-SE	Alcovy Road to SKC	U	Alcovy Road	SKC	0.0	100-120	AC	255.0	2015
SERC-SE	Mitchell - Moultrie	U	Mitchell	Lester	0.0	100-120	AC	216.0	2015
SERC-SE	McIntosh Sw to McIntosh South	P	McIntosh Sw	McIntosh South	1.5	100-120	AC	218.0	2012
SERC-SE	Fortson to Talbot County #1	U	Fortson	Talbot County #1	0.0	200-299	AC	807.0	2016
SERC-SE	Athena to Union Point	U	Athena	Union Point	0.0	100-120	AC	216.0	2021
SERC-SE	Palmyra - Slappy Dr 115kV Line	U	Albany #2	Slappy Drive	0.0	100-120	AC	216.0	2021
SERC-SE	Bonaire-Peach Blossom	U	Bonaire	Peach Blossom	0.0	100-120	AC	216.0	2015
SERC-SE	Bowen-Cartersville	U	Bowen	Cartersville	0.0	100-120	AC	255.0	2014
SERC-SE	Cherokee Rd-Ujnion Point	U	Cherokee Rd	Ujnion Point	0.0	100-120	AC	216.0	2021
SERC-SE	Deal Branch-Sylvania	U	Deal Branch	Sylvania	0.0	100-120	AC	124.0	2016
SERC-SE	Doublas/Lakeland-Pine Grove	P	Doublas/Lakeland	Pine Grove	15.0	200-299	AC	602.0	2019
SERC-SE	Douglasville-Factory Shoals/Groover	U	Douglasville	Factory Shoals/Groover	0.0	100-120	AC	207.0	2021
SERC-SE	Douglasville-Post Road/Aneewakee	U	Douglasville	Post Road/Aneewakee	0.0	100-120	AC	255.0	2021

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SERC-SE	East Point-Camp Creek	U	East Point	Camp Creek	0.0	200-299	AC	596.0	2018
SERC-SE	First Avenue-Victory Drive	U	First Avenue	Victory Drive	0.0	100-120	AC	199.0	2015
SERC-SE	Fortson-Talbot #2	U	Fortson	Talbot #2	0.0	200-299	AC	433.0	2016
SERC-SE	Franklin Jct-Mulberry Jct	P	Franklin Jct	Mulberry Jct	14.0	200-299	AC	807.0	2015
SERC-SE	Hickory Level-W Villa Rica	U	Hickory Level	W Villa Rica	0.0	100-120	AC	216.0	2019
SERC-SE	Leach Road-Bark Camp	U	Leach Road	Bark Camp	0.0	100-120	AC	216.0	2013
SERC-SE	Ludowici Pri-West Brunswick	U	Ludowici Pri	West Brunswick	0.0	100-120	AC	216.0	2018
SERC-SE	Marietta/Roswell Rd.-Marietta #4	U	Marietta/Roswell Rd.	Marietta #4	0.0	100-120	AC	269.0	2021
SERC-SE	McIntosh-Jasper	U	McIntosh	Jasper	0.0	100-120	AC	301.0	2016
SERC-SE	Meldrim-River	U	Meldrim	River	0.0	100-120	AC	255.0	2018
SERC-SE	Statesboro Pri-Langston	U	Statesboro Pri	Langston	0.0	100-120	AC	216.0	2016
SERC-SE	Thalmann-West Brunswick	U	Thalmann	West Brunswick	0.0	200-299	AC	1,205.0	2018
SERC-SE	Thalmann SS J-Cypress Point	U	Thalmann SS J	Cypress Point	0.0	100-120	AC	216.0	2019
SERC-SE	Arnold Mill - Hopewell	P	Arnold Mill	Hopewell	12.0	200-299	AC	602.0	2021
SERC-SE	Danial Siding - Riceboro	U	Danial Siding	Riceboro	0.0	100-120	AC	216.0	2021
SERC-SE	South Acworth - Woodstock	U	South Acworth	Woodstock	0.0	100-120	AC	255.0	2020
SERC-SE	Lassiter Road - North Marietta	U	Lassiter Road	North Marietta	0.0	100-120	AC	255.0	2017
SERC-W	Acadiana Area Improvement-Phase 2	UC	Labbe	Sellers Road	15.0	200-299	AC	829.0	2012
SERC-W	Upgrade walnut Grove - Swartz	U	Walnut Grove	Swartz	0.0	100-120	AC	276.0	2012
SERC-W	Upgrade Sterlington to Log Cabin 115	U	Bastrop	Log Cabin	0.0	100-120	AC	259.0	2012
SERC-W	upgrade North Bastrop - Log Cabin	U	North Bastrop	Log Cabin	0.0	100-120	AC	178.0	2012
SERC-W	Tillatoba-South Grenada	UC	Tillatoba	South Grenada	19.0	200-299	AC	500.0	2012
SERC-W	Lakeover-Northpark	U	Lakeover	Northpark	0.0	100-120	AC	231.0	2012
SERC-W	Cedar Hill-Plantation	U	Cedar Hill	Plantation	0.0	121-150	AC	478.0	2013
SERC-W	Plantation-Conroe	U	Plantation	Conroe	0.0	121-150	AC	478.0	2013
SERC-W	Jasper-Sam Rayburn Dam	U	Jasper	Sam Rayburn Dam	0.0	121-150	AC	275.0	2013
SERC-W	Snakefarm - Kenner Upgrade Line	U	Snakefarm	Kenner	0.0	100-120	AC	360.0	2012
SERC-W	SE LA Coastal Improvement-Phase 3	P	Oakville	Alliance	10.0	200-299	AC	515.0	2012
SERC-W	Iron Man to Tezcuco 230 kV line	P	Bayou Steel	Tezcuco	10.0	200-299	AC	520.0	2018
SERC-W	Springridge Rd-Wynndale	P	Springridge Rd	Wynndale	25.0	100-120	AC	260.0	2013
SERC-W	Church Rd-Getwell	P	Church Rd	Getwell	16.0	200-299	AC	520.0	2013
SERC-W	Getwell-Senatobia Industrial	C	Getwell	Senatobia Industrial	26.0	200-299	AC	520.0	2016
SERC-W	Holland Bottoms-Hamlet	UC	Holland Bottoms	Hamlet	20.0	151-199	AC	558.0	2012
SERC-W	Jonesboro-Hergett	U	Jonesboro	Hergett	0.0	151-199	AC	246.0	2012
SERC-W	Benton North-Benton South	UC	Benton N	Benton S	6.0	100-120	AC	175.0	2012
SERC-W	Westar Transmission Service	U	Monette	Paragould	0.0	100-120	AC	246.0	2012
SERC-W	Nelson-Moss Bluff 230 kV	P	Nelson	Moss Bluff (2)	7.0	200-299	AC	779.0	2012
SERC-W	Hot Springs Hamilton-Bismarck	P	HS Hamilton	Carpenter	10.0	100-120	AC	260.0	2015
SERC-W	Arcadia-Sailes 230kV (Op.@115kV)	P	Arcadia	Sailes	15.0	100-120	AC	261.0	2019
SERC-W	Mt. Olive to Arcadia Project Phase 2	P	Mt. Olive	Arcadia	15.0	100-120	AC	261.0	2019
SERC-W	NE Louisiana Improvement - Phase 2	P	Oakridge	Dunn	15.0	100-120	AC	261.0	2013
SERC-W	Sterlington to Downsville 115 kV line	U	Sterlington	Downsville	0.0	100-120	AC	239.0	2019
SERC-W	Northeast LA Improvement - Phase 3	U	Sterlington	Dunn	0.0	100-120	AC	262.0	2017
SERC-W	NE Louisiana Improvement - Phase 1	P	Swartz	Oakridge	15.0	100-120	AC	260.0	2013
SERC-W	Golden Meadow-Leeville 115 kV	U	Golden Meadow	Leeville	0.0	100-120	AC	239.0	2013
SERC-W	Raceland	C	Raceland	Waterford	4.0	200-299	AC	519.0	2018
SERC-W	Terrabone-Humph230kV(Op.@115)	C	Terrebone	Humphrey	15.0	100-120	AC	239.0	2018
SERC-W	Valentine to Clovelly 115 kV upgrade	U	Valentine	Clovelly	0.0	100-120	AC	239.0	2017
SERC-W	Lakeover-Northpark	UC	Lakeover	Northpark (2)	12.0	100-120	AC	231.0	2012
SERC-W	China-Stowell	C	China	Stowell	18.0	121-150	AC	265.0	2018
SERC-W	China-Amelia	P	China	Amelia (2)	10.0	200-299	AC	797.0	2016
SERC-W	Eastgate-Dayton Bulk	U	Eastgate	Dayton Bulk	0.0	121-150	AC	422.0	2013
SERC-W	Grimes-Bentwater	U	Grimes	Bentwater	0.0	121-150	AC	422.0	2020
SERC-W	Grimes-Mt. Zion	U	Grimes	Mt. Zion	0.0	121-150	AC	339.0	2019
SERC-W	Mt. Zion-Huntsville	U	Mt. Zion	Huntsville	0.0	121-150	AC	340.0	2020
SERC-W	Hartburg-Chisholm Road	C	Hartburg	Chisholm Road	12.0	200-299	AC	1,039.0	2017
SERC-W	Hickory Ridge-Eastgate	U	Hickory Ridge	Eastgate	0.0	121-150	AC	422.0	2016
SERC-W	McLewis-Helbig	U	McLewis	Helbig	0.0	200-299	AC	685.0	2012
SERC-W	McLewis-Helbig	U	McLewis	Helbig	0.0	200-299	AC	785.0	2018
SERC-W	Sabine-Port Neches Bulk	U	Sabine	Port Neches Bulk	0.0	121-150	AC	422.0	2017
SERC-W	Sabine-Linde	U	Sabine	Linde	0.0	121-150	AC	422.0	2018
SERC-W	Splendora-Apollo	U	Splendora	Apollo	0.0	121-150	AC	478.0	2016
SERC-W	Toledo Bend-Newton Bulk	U	Toledo Bend	Newton Bulk	0.0	121-150	AC	265.0	2013
SERC-W	West Memphis - Birmingham Steel	U	West Memphis	Birmingham Steel	0.0	400-599	AC	2,598.0	2012
SERC-W	Sheridan South 500 kV FG Upgrade	U	Sheridan	Mabelvale	0.0	400-599	AC	2,598.0	2014
SERC-W	Sheridan South 500 kV FG Upgrade	U	Sheridan	White Bluff	0.0	400-599	AC	2,598.0	2014
SERC-W	Sheridan South 500 kV FG Upgrade	U	Sheridan	El Dorado	0.0	400-599	AC	2,598.0	2014
SERC-W	Pine Bluff Voltage Support	P	White Bluff	PB Arsenal D	0.0	200-299	AC	532.0	2015

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SERC-W	Pine Bluff Voltage Support	P	Woodward	PB Arsenal D	0.0	200-299	AC	532.0	2015
SERC-W	Jim Hill Area Upgrades	P	Doniphan	Datto	15.0	151-199	AC	364.0	2017
SERC-W	Trumann-Trumann West - Upgrade	U	Trumann	Trumann West	0.0	151-199	AC	335.0	2016
SERC-W	Norfork-Calico Rock : Upgrade 161 kV	U	Calico Rock	Norfork	0.0	151-199	AC	335.0	2016
SERC-W	NLR Westgate - NLR Levy:	U	NLR Westgate	NLR Levy	0.0	100-120	AC	239.0	2013
SERC-W	AECC L&D 2 to Gillett 115 kV	P	L&D #2	Gillett	30.0	100-120	AC	260.0	2016
SERC-W	Calico Rock-Melbourne	U	Calico Rock	Melbourne	0.0	151-199	AC	335.0	2014
SERC-W	Woodward-WestPine Bluff	U	Woodward	Pine Bluff West	0.0	100-120	AC	319.0	2015
SERC-W	Woodward - Pine Bluff W.	U	PB McCamant	Pine Bluff West	0.0	100-120	AC	319.0	2015
SERC-W	Camden McGuire -Camden N. 115 KV	P	Camden McGuire	Camden N	4.0	100-120	AC	260.0	2014
SERC-W	LV Bagby-Reed:230kV(operate @115)	P	LV Bagby	Reed S	260.0	100-120	AC	260.0	2014
SERC-W	HS EHV - HS Industrial: Upgrade	U	HS EHV	HS Industrial	0.0	100-120	AC	239.0	2015
SERC-W	HS Industrial-HS Union Carbide:	U	HS Industrial	HS Union Carbide	0.0	100-120	AC	239.0	2015
SERC-W	HS Union Carbide - HS East	U	HS Union Carbide	HS East	0.0	100-120	AC	239.0	2015
SERC-W	Woodward-Pine Bluff Watson Chapel	U	Woodward	PB Watson Chapel	0.0	100-120	AC	390.0	2014
SERC-W	Arklahoma No. 2 to HS EHV East	U	Arklahoma	HS EHV (2)	0.0	100-120	AC	390.0	2017
SERC-W	Arklahoma No. 1 to HS EHV West	U	Aklahoma	HS EHV	0.0	100-120	AC	390.0	2017
SERC-W	Quitman to Bee Branch	U	Quitman	Bee Branch	0.0	151-199	AC	223.0	2017
SERC-W	Mabelvale - LR Kanis 115 kV	U	Mabelvale	LR Kanis	0.0	100-120	AC	266.0	2018
SERC-W	Mayflower - Morgan 115 kV Line:	U	Mayflower	Morgan	0.0	100-120	AC	398.0	2019
SERC-W	Holland Bottoms-Jacksonville N.	U	Holland Bottoms	Jacksonville N	0.0	100-120	AC	398.0	2018
SERC-W	Russellville E-Russellville N.Recon.116	U	Russellville East	Russellville North	0.0	151-199	AC	446.0	2018
SERC-W	LR West - LR Palm: Recon. 115 kV	U	LR West	LR Palm	0.0	100-120	AC	239.0	2018
SERC-W	NLR Westgate-LRGaines: Recon.115	U	NLR Westgate	LR Gaines	0.0	100-120	AC	255.0	2018
SERC-W	Paragould-Paragould S: Recon 161kV	U	Paragould	Paragould South	0.0	151-199	AC	335.0	2020
SERC-W	LR Boyle Park-LR West: Upgrades	U	LR Boyle Park	LR West	0.0	100-120	AC	260.0	2020
SERC-W	LR Mann Road - LR Chicot: Upgrades	U	LR Mann Rd	LR Chicot	0.0	100-120	AC	319.0	2020
SERC-W	Mabelvale-Bryant: Reconductor 115	U	Mabelvale	Bryant	0.0	100-120	AC	239.0	2018
SERC-W	LR South-LR Rock Creek: upgrade	U	LR South	LR Rock Creek	0.0	100-120	AC	398.0	2018
SERC-W	Upgrade Cheetah-Hot Springs Village	U	Cheetah	HS Village	0.0	100-120	AC	239.0	2018
SERC-W	LR Kanis - LR Markham: Reconductor	U	LR Kanis	LR Markham	0.0	100-120	AC	319.0	2018
SERC-W	Gum Springs to Amity	C	Gum Springs	(add breakers)Amity	40.0	100-120	AC	260.0	2018
SERC-W	Jonesboro-Jonesboro SPA Reconduct	U	Jonesboro	Jonesboro SPA	0.0	151-199	AC	546.0	2020
SERC-W	Baxter Wilson-S.E. Vicksburg	U	Baxter Wilson	S.E. Vicksburg	0.0	100-120	AC	260.0	2015
SERC-W	Franklin-McComb	P	Franklin	McComb	24.0	100-120	AC	398.0	2017
SERC-W	McComb-Tylertown	U	McComb	Tylertown	0.0	100-120	AC	199.0	2017
SERC-W	Murphy Tap-Belzoni Tap	P	Murphy Tap	Belzoni Tap	7.6	100-120	AC	108.0	2015
SERC-W	Jacinto-Splendora	U	Jacinto	Splendora	0.0	121-150	AC	478.0	2015
SERC-W	Jacinto-Cleveland	U	Jacinto	Cleveland	0.0	121-150	AC	478.0	2017
SERC-W	Toledo Bend-Leach	U	Toledo Bend	Leach	0.0	121-150	AC	265.0	2017
SERC-W	Leach-Newton Bulk	U	Leach	Newton Bulk	0.0	121-150	AC	287.0	2018
SERC-W	Sabine-Big Three	U	Sabine	Big Three	0.0	200-299	AC	685.0	2017
SERC-W	Buna-Evadale	U	Buna	Evadale	0.0	121-150	AC	287.0	2020
SERC-W	Rayburn-Mill Creek	U	Rayburn	Mill Creek	0.0	121-150	AC	287.0	2020
SERC-W	Porter-Apollo	U	Porter	Apollo	0.0	121-150	AC	286.0	2021
SERC-W	New Caney-Hickory Ridge	U	New Caney	Hickory Ridge	0.0	121-150	AC	478.0	2022
SERC-W	Amelia Bulk-Helbig	U	Amelia Bulk	Helbig	0.0	200-299	AC	785.0	2021
SERC-W	Gulfway-VFW Park	U	Gulfway	VFW Park	0.0	200-299	AC	685.0	2018
SERC-W	Moril-Delcambre	U	Moril	Delcambre	0.0	121-150	AC	251.0	2017
SERC-W	Willow Glen-Webre	U	Willow Glen	Webre	0.0	400-599	AC	1,732.0	2012
SERC-W	Bloomfield-Bosco	P	Bloomfield	Bosco	4.0	121-150	AC	250.0	2013
SERC-W	Bloomfield-Colton	C	Bloomfield	Colton	3.0	121-150	AC	225.0	2019
SERC-W	Moril-Hopkins	U	Moril	Hopkins	0.0	121-150	AC	381.0	2013
SERC-W	Champagne-Plaisance	U	Champagne	Plaisance	0.0	121-150	AC	287.0	2013
SERC-W	Gonzales-Sorrento	U	Gonzales	Sorrento	0.0	121-150	AC	260.0	2014
SPP	Hitchland Project	P	Hitchland	Moore County	50.0	200-299	AC	452.0	2012
SPP	Channing Project	P	Channing	Potter County	70.0	100-120	AC	146.0	2012
SPP	Johnson Draw	P	Johnson Draw	Amfrac/Mapco	0.1	100-120	AC	146.0	2012
SPP	Johnson Draw	P	Johnson Draw	Gaines	4.8	100-120	AC	164.0	2012
SPP	Johnson Draw	P	Taylor Switch	Johnson Draw	4.8	100-120	AC	164.0	2012
SPP	Johnson Draw	P	Higg	Johnson Draw	0.1	100-120	AC	146.0	2012
SPP	Hitchland - Ochiltree Project	P	Hitchland	Ochiltree Intg.	32.0	200-299	AC	452.0	2012
SPP	Carlsbad Ocotillo	P	Pecos	Ocotillo	5.8	100-120	AC	146.0	2012
SPP	Leighton Area Reliability Project	U	57th & Garland	84th & Leighton	0.0	100-120	AC	372.0	2012
SPP	Broken Bow to Broken Bow Wind	UC	Broken Bow	Broken Bow Wind	9.0	100-120	AC	95.0	2012
SPP	OU SW to Canadian SW 138kV	UC	OU Switchyard	Canadian Switchyard	11.0	121-150	AC	183.0	2012
SPP	Roswell-Capitan	P	Roswell Intg	Capitan Substation	5.7	100-120	AC	146.0	2012

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SPP	Sooner to Cleveland	UC	Sooner	Cleveland	35.2	300-399	AC	1,793.0	2012
SPP	East Clovis Conversion	P	Pleasant Hill	Curry County	1.5	100-120	AC	146.0	2012
SPP	Anadarko SW 138 kV	UC	Anadarko SW	Georgia Tap	5.0	121-150	AC	212.0	2012
SPP	Sunnnyside to Hugo	UC	Sunnyside	Hugo	120.0	300-399	AC	1,793.0	2012
SPP	Johnston County	UC	Caney Creek	Johnston County	25.0	121-150	AC	287.0	2012
SPP	ALP	UC	Bonin	Labbe	1.4	200-299	AC	693.0	2012
SPP	Heizer to Mullegren	P	Heizer	Mullegren	0.3	100-120	AC	Uknown	2012
SPP	Clay Center Jct-New Clay Center	UC	Clay Center Jct	New Clay Center SS	8.8	100-120	AC	262.0	2012
SPP	KSU-North Manhattan-Wildcat 115kV	UC	KSU-Wildcat	North Manhattan	2.0	100-120	AC	262.0	2012
SPP	Turk to NW Texarkana	UC	Turk	NW Texarkana	33.0	300-399	AC	1,336.0	2012
SPP	Massard - Oak Park	UC	Massard	Oak Park	0.5	121-150	AC	194.0	2012
SPP	Franklin SW to OU SW 138kV	UC	Franklin Switchyard	OU Switchyard	22.0	121-150	AC	183.0	2012
SPP	Rose Hill-Sooner 345kV	UC	Rose Hill	Sooner	100.0	300-399	AC	1,882.0	2012
SPP	Twin Church to South Sioux City	UC	Twin Church	South Sioux City	11.0	100-120	AC	240.0	2012
SPP	Twin Church to South Sioux City	UC	Twin Church	South Sioux City	7.0	100-120	AC	240.0	2012
SPP	GI L1369	P	Substation F	St. Libory Junction	7.0	100-120	AC	180.0	2012
SPP	Gill W-Waco 138kV	UC	Gill W	Waco	1.9	121-150	AC	314.0	2012
SPP	Reeding to Twin Lakes	UC	Reeding	Twin Lakes Switchyard	7.0	121-150	AC	144.0	2012
SPP	Meeker to Hammett 138kV	P	Meeker Switchyard	Hammett Substation	10.0	121-150	AC	183.0	2013
SPP	Central Lincoln Reliability Project	UC	17th & Holdrege	21st & N	1.3	100-120	AC	179.0	2013
SPP	Central Lincoln Reliability Project	R	20th & Pioneers	29th & Leighton	0.0	100-120	AC	121.0	2013
SPP	Central Lincoln Reliability Project	UC	21st & N	30th & A	1.5	100-120	AC	179.0	2013
SPP	Central Lincoln Reliability Project	UC	30th & A	56th & Everett	2.5	100-120	AC	186.0	2013
SPP	Randall County Intg.	P	Randall County	Amarillo South	8.5	200-299	AC	452.0	2013
SPP	Cherry St. Intg.	P	Harrington	Cherry St. Intg.	5.3	200-299	AC	452.0	2013
SPP	Cherry St. Intg.	P	Nichols	Cherry St. Intg.	6.4	100-120	AC	146.0	2013
SPP	Cherry St. Intg.	P	Cherry St. Intg.	Cherry St. substation	0.1	100-120	AC	146.0	2013
SPP	Pleasant Hill	P	Pleasant Hill	Curry County	0.2	100-120	AC	146.0	2013
SPP	Pleasant Hill	P	Pleasant Hill	Curry County	3.0	100-120	AC	146.0	2013
SPP	McAlester City to Dustin	P	McAlester City	Dustin	6.0	121-150	AC	321.0	2013
SPP	Cherry St. Intg.	P	Cherry St. Intg.	Hastings	4.0	100-120	AC	146.0	2013
SPP	Cherry St. Intg.	P	East Plant	Hastings	4.9	100-120	AC	146.0	2013
SPP	Goodyear-MacVicar-17th&Fairlawn	P	Goodyear	MacVicar	4.0	100-120	AC	262.0	2013
SPP	Seminole to Muskogee	UC	Seminole	Muskogee	100.0	300-399	AC	1,793.0	2013
SPP	Newhart Intg.	P	Potter County	Newhart Intg.	68.0	200-299	AC	452.0	2013
SPP	Cherry St. Intg.	P	Cherry St. Intg.	Northwest	8.3	100-120	AC	146.0	2013
SPP	Pleasant Hill	P	Pleasant Hill	Norton	0.2	100-120	AC	146.0	2013
SPP	Osbourne to Osbourne Tap	P	Osbourne	Osbourne Tap	2.0	151-199	AC	512.0	2013
SPP	Fairfax-Pawnee	P	Fairfax KAMO	Pawnee Sw. Station	16.3	121-150	AC	305.0	2013
SPP	Newhart Intg.	P	Newhart Intg.	Plant X	36.0	200-299	AC	452.0	2013
SPP	Axtell to Post Rock	UC	Axtell	Post Rock	125.0	300-399	AC	1,792.0	2013
SPP	Cherry St. Intg.	P	Cherry St. Intg.	Potter County	6.0	200-299	AC	452.0	2013
SPP	OG&E Renfrow interconnect	P	Wakita	Renfrow	25.0	121-150	AC	106.0	2013
SPP	Muncie to Armourdale Line	P	Muncie Substation	Armourdale Substation	0.1	151-199	AC	318.0	2013
SPP	Muncie to Center City Line	P	Muncie Substation	Center City Substation	0.1	151-199	AC	318.0	2013
SPP	Clarks to Central City No.	P	Clarks	Central City No.	12.0	100-120	AC	80.0	2014
SPP	TransCanada-Burns 138kV	P	Burns Tap	TC-Burns	9.0	121-150	AC	314.0	2014
SPP	TransCanada-Riley 115kV	P	New Clay Center SS	TC-Riley	10.0	100-120	AC	262.0	2014
SPP	Pleasant Hill	P	Pleasant Hill	FEC Clovis (Intg. #3)	3.0	100-120	AC	146.0	2014
SPP	Newhart Intg.	P	Newhart	Kress	18.0	100-120	AC	146.0	2014
SPP	Goodyear-MacVicar-17th&Fairlawn	P	MacVicar	17th & Fairlawn	4.0	100-120	AC	262.0	2014
SPP	Woodward EHV to Border	P	Woodward EHV	Border	72.0	300-399	AC	1,793.0	2014
SPP	Plainview City	P	Plainview City	Cox	10.0	100-120	AC	146.0	2014
SPP	Shipe Road to E. Centerton	P	Shipe Road	E. Centerton	9.0	151-199	AC	512.0	2014
SPP	Border to Hitchland	P	Border Substation	Hitchland	220.0	300-399	AC	3,586.0	2014
SPP	Woodward EHV to Hitchland	P	Woodward EHV	Hitchland	13.5	300-399	AC	1,793.0	2014
SPP	Newhart Intg.	P	Newhart	Lamton	19.0	100-120	AC	146.0	2014
SPP	Woodward EHV to Medicine Lodge	P	Woodward EHV	Medicine Lodge	115.0	300-399	AC	1,793.0	2014
SPP	Valliant to NW Texarkana	P	Valliant	NW Texarkana	76.0	300-399	AC	1,793.0	2014
SPP	Hitchland-Woodward	P	Hitchland	OGE Woodward Sub.	30.0	300-399	AC	1,800.0	2014
SPP	TUCO-Woodward	P	TUCO	OGE Woodward Sub.	180.0	300-399	AC	1,355.0	2014
SPP	Plainview City	P	Kress Intg.	Plainview City	18.0	100-120	AC	146.0	2014
SPP	Flint Creek to Shipe Road	P	Flint Creek	Shipe Road	18.0	300-399	AC	1,336.0	2014
SPP	Newhart Intg.	P	Newhart Intg.	Swisher County	19.0	200-299	AC	452.0	2014
SPP	Newhart Intg.	P	Newhart	Castro	24.0	100-120	AC	146.0	2014
SPP	Wolcott to Nearman Line	P	Wolcott Substation	Nearman Substation	5.0	151-199	AC	1,170.0	2014
SPP	SW Reliability Project	P	SW 7th & Bennet	40th & Rokeby	5.4	100-120	AC	372.0	2015

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SPP	GREENWOOD-LONEJACK	P	GREENWOOD	LONE JACK	4.7	151-199	AC	233.0	2015
SPP	IATAN-NASHUA	P	IATAN	NASHUA	30.0	300-399	AC	2,546.0	2015
SPP	Stegall / WAPA to Stegall/BEPC	P	Stegall / WAPA	Stegall/ BEPC	3.3	200-299	AC	Unknown	2015
SPP	Kinsley	C	Kinsley	various options	35.0	100-120	AC	Unknown	2015
SPP	Monett	P	Monett Sub #383	South of Monett, MO	9.2	151-199	AC	268.0	2016
SPP	Shipe Road to E. Rogers	P	Shipe Road	E. Rogers	9.0	300-399	AC	1,336.0	2016
SPP	E. Rogers to Osage Creek	P	E. Rogers	Osage Creek	32.0	300-399	AC	1,336.0	2016
SPP	Fisher to Barber Substation	C	Fisher Substation	Barber Substation	2.5	151-199	AC	1,170.0	2016
SPP	Kaw to Barber Transmission Line	C	Kaw Substation	Barber Substation	2.0	151-199	AC	585.0	2016
SPP	Speaker to Kaw Transmission Line	C	Speaker Substation	Kaw Substation	3.0	151-199	AC	585.0	2016
SPP	Kaw-West to Speaker Line	C	Kaw-West Sub	Speaker Sub	4.0	151-199	AC	585.0	2016
SPP	CEDARNILES-CLARE	P	CEDAR NILES	CLARE	4.8	151-199	AC	293.0	2017
SPP	SIBLEY-MARYVILLE	P	SIBLEY	MARYVILLE	105.0	300-399	AC	1,792.0	2017
SPP	MARYVILLE-NEBRASKA	P	MARYVILLE	NEBRASKA	70.0	300-399	AC	1,792.0	2017
SPP	Speaker to Everett Transmission Line	C	Speaker Substation	Everett Substation	3.0	151-199	AC	585.0	2017
SPP	Everett to Quindaro Line	C	Everett Substation	Quindaro Substation	4.5	151-199	AC	585.0	2017
SPP	Woodward EHV to Woodring	C	Woodward EHV	Woodring	95.0	300-399	AC	1,793.0	2020
SPP	Twin Lakes to OG&E Crescent 138kV	UC	Twin Lakes Switchyard	OG&E Crescent Sub.	7.0	121-150	AC	183.0	2012
SPP	Anadarko SW to Washita	UC	Anadarko SW	Washita	1.0	121-150	AC	183.0	2012
SPP	Loco SW to Healdton-Butler Jct.	P	Loco SW	Healdton-Butler Jct.	13.0	121-150	AC	183.0	2013
SPP	Elk City to Russell SW 138kV	P	Elk City Substation	Russell Switchyard	46.0	121-150	AC	183.0	2015
SPP	Cache to Grandfield 138kV	P	Cache Switchyard	Grandfield Switchyard	58.0	121-150	AC	183.0	2016
SPP	Anadarko to OU	P	Anadarko Switchyard	OU Switchyard	11.1	121-150	AC	106.0	2016
SPP	Snyder SW to Paradise	P	Snyder Switchyard	Paradise Substation	9.9	121-150	AC	183.0	2016
SPP	South Joplin	P	Stateline #439	Reinmiller #393	12.0	151-199	AC	428.0	2017
SPP	Snyder SW to Russell	P	Snyder Switchyard	Russell Switchyard	44.0	121-150	AC	106.0	2017
SPP	Anadarko to Paradise	P	Anadarko Switchyard	Paradise Substation	40.0	121-150	AC	212.0	2018
WECC-US	Sundance–Pinal Central 230 kV Line	P	Coolidge	Coolidge	6.0	200-299	AC	1,200.0	2014
WECC-US	Sun Valley – Trilby Wash 230 kV Line	P	Buckeye AZ	Surprise AZ	15.0	200-299	AC	1,200.0	2014
WECC-US	TS2– Palm Valley 230 kV Line	P	Surprise AZ	Goodyear AZ	12.0	200-299	AC	1,200.0	2015
WECC-US	TS2– Trilby Wash 230 kV Line	P	Surprise AZ	Surprise AZ	12.0	200-299	AC	1,200.0	2015
WECC-US	North Gila - TS8 230 kV Line	P	Yuma AZ	Yuma AZ	11.0	200-299	AC	Unknown	2014
WECC-US	Delaney - Palo Verde 500 kV Line	P	Maricopa Co. AZ	Wintersburg AZ	15.0	400-599	AC	1,000.0	2013
WECC-US	Palo Verde - North Gila 500 kV line	P	Wintersburg AZ	Yuma AZ	115.0	400-599	AC	1,200.0	2014
WECC-US	Sun Valley – Morgan 500 kV Line	P	Buckeye AZ	Peoria AZ	40.0	400-599	AC	1,200.0	2016
WECC-US	Delaney - Sun Valley 500 kV Line	P	Maricopa Co. AZ	Buckeye AZ	28.0	400-599	AC	Unknown	2014
WECC-US	West Station-Portland #2 115	P	West Station 115 kV bus	Portland 115 kV bus	16.0	100-120	AC	222.0	2012
WECC-US	Reader-Rattlesnake Butte 115 kV Line	P	Reader 115 Sub	Rattlesnake Butte115Sub	36.0	100-120	AC	222.0	2012
WECC-US	Baculite Mesa-Overton 115kV rebuild	P	Baculite Mesa 115 kV	Overton 115 kV bus	4.0	100-120	AC	222.0	2012
WECC-US	Pueblo-West Station 115 kV Rebuild	P	Pueblo 115 kV bus	West Station 115 kV bus	5.0	100-120	AC	222.0	2013
WECC-US	Greenhorn-Reader 115 kV Rebuild	P	Greenhorn 115 kV bus	Reader 115 kV bus	5.0	100-120	AC	222.0	2013
WECC-US	La Junta Interconnect	P	La Junta BHCE 115 kV	La Junta TSGT 115 kV bus	1.0	100-120	AC	222.0	2014
WECC-US	Teckla-Osage 230 kV line	P	Teckla 230 kV bus	Osage 230 kV bus	60.0	200-299	AC	554.0	2014
WECC-US	Osage-Lange 230 kV line	P	Osage 230 kV bus	Lange 230 kV bus	75.0	200-299	AC	554.0	2015
WECC-US	Lower Monumental-Central Fer	P	Clyde, WA	Central Ferry, WA	38.0	400-599	AC	3949/4936	2022
WECC-US	Big Eddy-Knight 500kV	P	The Dalles, OR	Goldendale, WA	28.0	400-599	AC	3949/4936	2013
WECC-US	Castle Rock-Troutdale 500 kV line	P	Castle Rock, WA	Troutdale, OR	70.0	400-599	AC	Unknown	2015
WECC-US	Rocky Reach-Chelan #1 Rebuild	C	Rocky Reach	Chelan #1	29.0	100-120	AC	Unknown	2021
WECC-US	Entiat Valley Tap	P	Entiat	Crum Canyon	7.5	100-120	AC	281.0	2012
WECC-US	Happy Jack-North Range 115 kV Line	P	Happy Jack Sub	North Range Sub	1.0	100-120	AC	222.0	2012
WECC-US	Corlett-Swan Ranch 115 kV Line	P	Corlett Sub	Swan Ranch Sub	3.0	100-120	AC	222.0	2013
WECC-US	Swan Ranch-Cheyenne South 115 kV	P	Swan Ranch Sub	Cheyenne South Sub	6.0	100-120	AC	222.0	2013
WECC-US	Pump Station No.9	P	New Bowdoin Sub	Pump Station No. 9	48.0	100-120	AC	150.0	2012
WECC-US	Douglas-Rapids 230-kV Line	P	Douglas Switchyard	Rapids Switchyard	15.0	200-299	AC	555.0	2013
WECC-US	Afton-Airport-Jornada 115 kV Line	C	Las Cruces, NM	Las Cruces, NM	30.0	100-120	AC	156.6	2015
WECC-US	Santa Teresa-Montoya 115 kV Line	P	El Paso, Tx	El Paso,Tx	10.3	100-120	AC	156.6	2012
WECC-US	Organ (LE1)-Arroyo 115 kV Line	P	Las Cruces, NM	Las Cruces, NM	6.6	100-120	AC	156.6	2012
WECC-US	Organ (LE1)-Jornada 115 kV Line	P	Las Cruces, NM	Las Cruces, NM	6.6	100-120	AC	156.6	2012
WECC-US	Wheeler Rd Tap-Ruff Reconductor	C	Sand Dunes Larson	Ruff Tap	8.0	100-120	AC	202.0	2012
WECC-US	Rocky Ford Dover 115 kV	C	Rocky Ford	Larson (Dover)	8.5	100-120	AC	202.0	2014
WECC-US	Wanapum _ Priest Rapids Mid Way	C	Wanapum	Midway	23.9	200-299	AC	797.0	2018
WECC-US	Columbia Rocky Ford 230 kV line	C	Columbia	Larson	30.5	200-299	AC	797.0	2013
WECC-US	Hemingway-Boardman Transm	C	Walters Ferry, ID	Bowmont, ID	13.0	200-299	AC	565.0	2016
WECC-US	Gateway West Transm.	C	Shoshone, ID	Pocatello, ID	0.0	300-399	AC	1,386.0	2019
WECC-US	Gateway West Transm.	C	American Falls, ID	Pocatello, ID	32.0	300-399	AC	1,386.0	2019
WECC-US	Gateway West Transm.	C	Shoshone, ID	Pocatello, ID	0.0	300-399	AC	2,079.0	2019
WECC-US	Gateway West Transm.	C	Shoshone, ID	American Falls, ID	84.0	400-599	AC	3,000.0	2019

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
WECC-US	Gateway West Transm.	C	Shoshone, ID	Walters Ferry, ID	126.0	400-599	AC	3,000.0	2021
WECC-US	Gateway West Transm.	C	Hollister, ID	Shoshone, ID	34.0	400-599	AC	3,000.0	2019
WECC-US	Gateway West Transm.	C	Hollister, ID	Walters Ferry, ID	161.0	400-599	AC	3,000.0	2019
WECC-US	Gateway West Transm.	C	Downey, ID	American Falls, ID	55.0	400-599	AC	3,000.0	2019
WECC-US	Hemingway-Boardman Transm	C	Walters Ferry, ID	Boardman, OR	300.0	400-599	AC	3,000.0	2016
WECC-US	Midpoint-Boise Bench: Loop Justice	P	Midpoint, ID	DRAM, ID	0.0	200-299	AC	351.0	2012
WECC-US	Midpoint-Boise Bench: Loop Justice	P	Midpoint, ID	King, ID	24.0	200-299	AC	351.0	2012
WECC-US	Midpoint-Boise Bench: Loop Justice	P	King, ID	DRAM, ID	80.0	200-299	AC	351.0	2012
WECC-US	Langley Gulch Generation Project	UC	S. of New Plymouth, ID	Caldwell, ID	20.0	121-150	AC	339.0	2012
WECC-US	Barren Ridge Renewable	C	Barren Ridge CA	Rinaldi CA	76.0	200-299	AC	650.0	2015
WECC-US	Barren Ridge Renewable	C	Haskell CA	Castaic CA	12.0	200-299	AC	950.0	2015
WECC-US	Barren Ridge Renewable	C	Barren Ridge CA	Haskell CA	61.0	200-299	AC	950.0	2015
WECC-US	Scattergood-Olympic 230kV Line 1	P	Scattergood Gen St.	Olympic Receiving Station	12.0	200-299	AC	500.0	2014
WECC-US	Los Alamos Service Area Cap.Upgrade	C	Norton	STA	12.0	100-120	AC	285.0	2015
WECC-US	Hooper Springs-Lanes Creek 115 kV	P	Caribu County, ID	Caribu County, ID	32.0	121-150	AC	Unknown	2014
WECC-US	Montana Alberta Tie Line	P	120S	Montana	326.0	200-299	AC	300.0	2012
WECC-US	VARS (Thunderbird - Iron Mt. #1)	C	Las Vegas NV	Las Vegas NV	16.0	200-299	AC	810.0	2018
WECC-US	VARS (Harry Allen - NW fold #1)	C	Las Vegas NV	Las Vegas NV	1.0	200-299	AC	810.0	2018
WECC-US	VARS project (NW - Iron Mt. #1)	C	Las Vegas NV	Las Vegas NV	16.0	200-299	AC	810.0	2018
WECC-US	Mead - Amaragosa 500kV	C	Boulder City NV	Lathrop WellsNV	110.0	400-599	AC	3,000.0	2012
WECC-US	Harry Allen - Northwest #2 500kV	C	Las Vegas NV	Las Vegas NV	28.0	400-599	AC	3,000.0	2018
WECC-US	Northwest - Amargosa 500kV	C	Las Vegas NV	Lathrop WellsNV	75.0	400-599	AC	3,000.0	2014
WECC-US	VEA/NVE230kV Intercon@ NW	P	Las Vegas NV	Mercury NV	75.0	200-299	AC	1,200.0	2012
WECC-US	Sunrise500kV(Sunrise-Winterwood 1	P	Las Vegas NV	Las Vegas NV	1.0	200-299	AC	1,200.0	2018
WECC-US	Sunrise500kV(Sunrise-Winterwood 2	P	Las Vegas NV	Las Vegas NV	1.0	200-299	AC	1,200.0	2018
WECC-US	Sunrise 500kV(Sunrise - Equestrian #1	P	Las Vegas NV	Las Vegas NV	18.0	200-299	AC	810.0	2018
WECC-US	Sunrise 500kV(Sunrise - Equestrian #2	P	Las Vegas NV	Las Vegas NV	18.0	200-299	AC	810.0	2018
WECC-US	Sunrise 500kV(Sunrise - Clark #1)	P	Las Vegas NV	Las Vegas NV	4.0	200-299	AC	810.0	2018
WECC-US	Pecos - Brooks 230 kV Line	P	Las Vegas NV	Las Vegas NV	5.0	200-299	AC	810.0	2018
WECC-US	Sunrise 500 kV (Mead-HA fold #1)	P	Las Vegas NV	Las Vegas NV	8.0	400-599	AC	3,000.0	2018
WECC-US	Sunrise 500 kV (Mead - HA fold #2)	P	Las Vegas NV	Las Vegas NV	8.0	400-599	AC	3,000.0	2018
WECC-US	Harry Allen / Eldorado 500kV #1	P	Las Vegas NV	Las Vegas NV	0.0	400-599	AC	Unknown	2015
WECC-US	Harry Allen / Eldorado 500kV #3	P	Las Vegas NV	Las Vegas NV	0.0	400-599	AC	Unknown	2016
WECC-US	Path 18 46 MW Upgrade	P	Mill Creek, MT	AMPS Substation, ID	0.0	200-299	AC	337 - 383	2013
WECC-US	Mountain States Trans. Intertie(MSTI)	P	Townsend, MT	Midpoint, ID	460.0	400-599	AC	1,500.0	2017
WECC-US	500 kV Upgrade	P	Broadwater or Colstrip	Garrison- BPA Existing	0.0	400-599	AC	2200/3000	2017
WECC-US	Tonasket/Aeneas 115-KV Line	C	Tonasket Switchyard	Aeneas Substation	16.1	100-120	AC	100.0	2013
WECC-US	So. Pateros-Twisp 115-kV Line	P	Watson Draw Tap Switch	Gold Creek Substation	13.7	100-120	AC	100.0	2013
WECC-US	No. Pateros-Twisp 115-kV Line	P	Gold Creek Substation	Twisp Switchyard	14.5	100-120	AC	100.0	2013
WECC-US	Red Butte/Central to St George	P	Central, UT	St.George,UT	20.0	121-150	AC	600.0	2019
WECC-US	Windstar-Aeolus 230 kV #1 line	P	Windstar,WY	Carbon County, WY	76.0	200-299	AC	888.0	2015
WECC-US	Windstar-Aeolus 230 kV #2 line	P	Windstar,WY	Carbon County, WY	122.0	200-299	AC	888.0	2015
WECC-US	DJ-Aeolus 230 kV line rebuild w/1272	P	Aeolus, WY	Dave Johnston Sub.,WY	70.0	200-299	AC	888.0	2015
WECC-US	Three Peaks-Hurricane-St George 345	P	Sigurd, UT	Hurricane, Utah	170.0	300-399	AC	1,163.0	2019
WECC-US	Clover-Limber 500 kV at 345 kV	P	Mona, UT	Tooele County,UT	65.0	300-399	AC	3,681.5	2013
WECC-US	Limber-Oquirrh 2-345 kV lines	P	Tooele County, UT	South Jordan, UT	32.0	300-399	AC	1,396.0	2013
WECC-US	Sigurd-Red Butte 345 kV #2 line	P	Sigurd, UT	Central,UT	165.0	300-399	AC	1,163.0	2014
WECC-US	Oquirrh-Terminal 345 kV line	P	South Jordan, UT	SLC,UT	28.0	300-399	AC	1,332.0	2014
WECC-US	Aeolus-Clover 500 kV line#1	P	Carbon County, WY	Mona, UT	400.0	400-599	AC	3,681.5	2018
WECC-US	Aeolus-Anticline/Bridger 500 kV #1	P	Carbon County, WY	Rock Springs, WY	154.0	400-599	AC	3,681.5	2015
WECC-US	Anticline/Bridger-Populus 500 kV #1	P	Rock Springs, WY	Downey, ID	203.0	400-599	AC	3,681.5	2015
WECC-US	Wallula to McNary 230 kV Line	P	Wallula	McNary	30.0	200-299	AC	500.0	2013
WECC-US	Vantace to Pomona	P	Vantage	Pomona Heights	40.0	200-299	AC	500.0	2013
WECC-US	Embarcadero-Potrero 230kV (T1032)	C	Embarcadero	Potrero	3.0	200-299	AC	Unknown	2012
WECC-US	Midway-Morro Bay 230kV (T1093A)	C	Midway	San Luis Obispo Solar	68.0	200-299	AC	Unknown	2012
WECC-US	Rio Oso-Atlantic (T1001)	C	Rio Oso	Gold Hill	28.5	200-299	AC	Unknown	2012
WECC-US	Tesla-Newark 230kV Path (T670A)	C	Telsa Substation	Newark Substation	54.0	200-299	AC	1,366.0	2013
WECC-US	Bay Area Bulk Project (T073)	C	Collinsvills, CA	Pittsburg, CA	8.0	200-299	AC	800/2146	2016
WECC-US	Contra Costa - Moraga 230kV (T991)	C	Contra Costa Sub.	Moraga Substation	54.0	200-299	AC	683.0	2014
WECC-US	Pittsburg - Tesla 230kV (T984)	C	Pittsburg Substation	Telsa Substation (	62.0	200-299	AC	683.0	2014
WECC-US	Vaca Dixon - Lakeville 230kV (T603B)	C	Vaca Dixon (Vacaville)	Lakeville Sub. (Petaluma)	80.0	200-299	AC	658.0	2014
WECC-US	CAN/PAC NW– N Cal. (T1051)	C	Selkirk BC	Collinsville CA	2,500.0	400-599	AC	3,000.0	2016
WECC-US	Central California Clean Energy(T971)	C	Bakersfield, Ca	Fresno, Ca	280.0	400-599	AC	2,146.0	2017
WECC-US	Atwater-Merced Reliability (T1026)	P	Cressey	Gallo	12.0	100-120	AC	Unknown	2012
WECC-US	Bay Meadows 4/0 Cu (T249)	P	San Mateo	Bay Meadows	4.5	100-120	AC	Unknown	2012
WECC-US	Gold Hill - Horseshoe (T444D)	P	Placer	Horseshoe	16.0	100-120	AC	Unknown	2012
WECC-US	Midway - Renfro 115 kV (T1090)	P	Midway	Renfro	33.0	100-120	AC	Unknown	2012
WECC-US	Missouri Flat - Gold Hill (T444C)	P	Missouri Flat	Gold Hill	25.0	100-120	AC	Unknown	2012

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
WECC-US	S. San Matero Cap Increase (T920A)	P	Ames	Ravenswood&San Matero	44.0	100-120	AC	Unknown	2014
WECC-US	Newark - Ravenwood (T982)	P	Newark Substation)	Ravenswood Substation	18.0	200-299	AC	1,366.0	2014
WECC-US	Horizon Phase 1	P	Horizon	Keeler	1.5	200-299	AC	900.0	2012
WECC-US	Blue Lake - Gresham 230 kV Line	P	Blue Lake	Gresham	6.1	200-299	AC	900.0	2017
WECC-US	Cascade Crossing	P	Coyote Springs	Bethel	200.0	400-599	AC	1,500.0	2017
WECC-US	Sandia-North Line	C	North	Montano	2.3	100-120	AC	200.0	2014
WECC-US	Rio Puerco P. 2 bisection@Rio Puerco	P	San Juan	B-A	0.0	300-399	AC	Unknown	2014
WECC-US	Dixon - Horseshoe 230 kV Line	UC	Fort Collins CO	Loveland CO	10.0	200-299	AC	472.0	2012
WECC-US	Eldorado - Plainview 115kV	P	Eldorado	Plainview	4.0	100-120	AC	150.0	2013
WECC-US	Niwot - Gunbarrel 230kV	P	Niwot	Gunbarrel	2.3	200-299	AC	Unknown	2012
WECC-US	Rifle - Parachute	P	Rifle	Parachute	21.0	200-299	AC	576.0	2015
WECC-US	Pawnee - Daniels Park 345kV	P	Pawnee	Daniels Park	124.0	300-399	AC	1,200.0	2018
WECC-US	Kitsap County	P	Manchester WA	Long Lake WA	0.3	100-120	AC	320.0	2012
WECC-US	Pierce County	P	Sumner WA	Puyallup WA	3.0	100-120	AC	Unknown	2012
WECC-US	Kitsap County	P	Manchester WA	Poulsbo WA	15.0	100-120	AC	Unknown	2018
WECC-US	Whatcom County	P	Sumas WA	Everson WA	10.0	100-120	AC	314.0	2018
WECC-US	Whatcom County	P	Ferndale WA	Custer WA	8.0	100-120	AC	Unknown	2018
WECC-US	King County	P	Kenmore WA	Kirkland WA	4.0	100-120	AC	Unknown	2021
WECC-US	North King County	P	Kirkland WA	Sammamish WA	5.2	100-120	AC	314.0	2013
WECC-US	South King County	P	Sumner WA	Auburn WA	2.3	100-120	AC	314.0	2017
WECC-US	South King County	P	Sumner WA	Auburn WA	2.5	100-120	AC	314.0	2017
WECC-US	South King County	P	Federal Way WA	Puyallup WA	6.3	100-120	AC	314.0	2017
WECC-US	South King County	P	Berrydale WA	Enumclaw WA	18.0	100-120	AC	314.0	2017
WECC-US	Pierce and Thurston Counties	P	Puyallup WA	Lacey WA	15.0	100-120	AC	314.0	2015
WECC-US	Thurston County	P	Lacey WA	Yelm WA	15.0	100-120	AC	Unknown	2015
WECC-US	King County	P	Renton WA	Bellevue WA	7.0	100-120	AC	314.0	2017
WECC-US	King County	P	Berrydale WA	Snoqualmie WA	10.0	100-120	AC	314.0	2017
WECC-US	Thurston County	P	Lacey WA	Lacey WA	10.0	200-299	AC	Unknown	2013
WECC-US	Pierce County	P	Sumner WA	Puyallup WA	8.0	200-299	AC	733.0	2014
WECC-US	King County	P	Sammamish WA	Renton WA	16.0	200-299	AC	Unknown	2017
WECC-US	Kitmat Kemano (35%) Series Comp.	P	Kitimat, BC	Kemano, BC	0.0	200-299	AC	Unknown	2014
WECC-US	Devers - Mirage 230 kV	C	Palm Springs CA	Mirage CA	15.0	200-299	AC	1,240.0	2019
WECC-US	Eldorado-Ivanpah Transmission (EITP)	C	Boulder City NV	Primm NV	35.0	200-299	AC	Unknown	2013
WECC-US	Colorado River - Devers 500 kV	C	Colorado River CA	Devers CA	115.0	400-599	AC	2,700.0	2013
WECC-US	Devers - Valley 500 kV	C	Valley CA	Devers CA	42.0	400-599	AC		2013
WECC-US	San Joaquin Cross Valley Loop	P	Rector CA	Springville CA	38.0	200-299	AC	3,230.0	2014
WECC-US	Tehachapi Renewable Segments 4-11	P	Tehachapi CA	Mira Loma CA	250.0	400-599	AC	3,950.0	2015
WECC-US	Sunrise Powerlink (-Sycamore 230kV)	UC	Suncrest	Sycamore Canyon	28.0	200-299	AC	1,326.0	2012
WECC-US	Sunrise Powerlink	UC	Suncrest	Sycamore Canyon	28.0	200-299	AC	1,326.0	2012
WECC-US	Sunrise Powerlink (IV-Central 500kV)	UC	Imperial Valley	Suncrest	91.0	400-599	AC	2,598.0	2012
WECC-US	Dixie-Oreana RTI Zone1 Collector 345	C			301.0	300-399	AC	1,000.0	2016
WECC-US	Blackhawk - Amaragosa 500kV	C	Carson City, NV	Las Vegas NV	265.0	400-599	AC	3,000.0	2018
WECC-US	Robinson - Midpoint 500kV (GBT)	C	Twin Falls ID	Ely NV	280.0	400-599	AC	3,000.0	2014
WECC-US	Cal Sub - Bordertown 120kV	P	Bordertown, NV	Verdi, CA	12.0	100-120	AC	200.0	2014
WECC-US	Carson Lake	P	Carson Lake, NV	Fallon, NV	20.0	200-299	AC	200.0	2013
WECC-US	East Tracy – Blackhawk 345 kV Line	P	Reno NV	Dayton NV	17.0	300-399	AC	600.0	2012
WECC-US	Tracy-Ft. Sage 345 kV Line	P	Reno NV	Doyle CA	50.0	300-399	AC	600.0	2018
WECC-US	Robinson - Harry Allen 500 kV Line	P	Ely NV	Las Vegas NV	250.0	400-599	AC	3,000.0	2013
WECC-US	Robinson - Eldorado 500kV Line (GBT)	P	Ely NV	Boulder City NV	230.0	400-599	AC	3,000.0	2014
WECC-US	Blackhawk- Mira Loma 345 kV Line	P	Dayton NV	Reno NV	15.0	300-399	AC	600.0	2018
WECC-US	Ball to Pfister	P	Gilbert AZ	Queen Creek AZ	8.0	200-299	AC	875.0	2019
WECC-US	Southeast Valley Project	P	Maricopa AZ	Mesa AZ	0.0	200-299	AC	1,405.0	2014
WECC-US	Pfister to Abel	P	Queen Creek AZ	Florence AZ	12.0	200-299	AC	875.0	2014
WECC-US	Desert Basin-Pinal South Project	P	Casa Grande, AZ	Coolidge AZ	21.0	200-299	AC	833.0	2014
WECC-US	Southeast Valley Project	P	Maricopa AZ	Mesa AZ	87.0	400-599	AC	1,405.0	2014
WECC-US	SUNZIA SOUTHWEST TRANSMISSION	P	Corona, NM	Coolidge, AZ	500.0	400-599	AC	3,000.0	2016
WECC-US	Vail - Irvington 345 kV	C	Vail, AZ	Tucson, AZ	11.0	300-399	AC	1,195.0	2022
WECC-US	Irvington - South 345 kV	C	Tucson, AZ	Sahuarita, AZ	16.0	300-399	AC	1,195.0	2022
WECC-US	Tortolita - North Loop 345 kV	C	Red Rock, AZ	Marana, AZ	15.0	300-399	AC	1,195.0	2022
WECC-US	Vail - South 345 kV	C	Vail, AZ	Sahuarita, AZ	14.0	300-399	AC	1,195.0	2022
WECC-US	Springerville - Greenlee 345 kV	C	Springerville, AZ	Greenlee, AZ	110.0	300-399	AC	1,195.0	2022
WECC-US	Tortolita - South 345 kV	C	Red Rock, AZ	Sahuarita, AZ	68.0	300-399	AC	1,195.0	2022
WECC-US	Tortolita - Winchester 500 kV	C	Red Rock, AZ	Benson, AZ	80.0	400-599	AC	Unknown	2022
WECC-US	Westwing - South #2	C	Phoenix, AZ	Sahuarita, AZ	68.0	400-599	AC	Unknown	2022
WECC-US	Pinal Central - Tortolita 500 kV	P	Nine Mile Corner, AZ	Red Rock, AZ	38.0	400-599	AC	1,732.0	2014
WECC-US	Hughson-Grayson	P	Hughson	Grayson	11.5	100-120	AC	163.0	2012
WECC-US	Hughson-Grayson	P	Grayson	Taylor	16.0	100-120	AC	163.0	2012
WECC-US	Almond 2 PP	UC	Almond	Grayson	0.3	100-120	AC	163.0	2012

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
WECC-US	Pagosa-Ignacio 115 kV Line	C	Pagosa Springs, CO	To Be Determined	37.0	100-120	AC	166.0	2016
WECC-US	East Montrose-South Canal 115 kV	C	Montrose, CO	Montrose County, CO	8.0	100-120	AC	166.0	2016
WECC-US	Santa Rosa-Gladstone 230kV Tie Line	C	So. of Gladstone, NM	Santa Rosa, NM	80.0	200-299	AC	Unknown	2018
WECC-US	Lamar - Front Range Transmission	C	Lamar, CO area	Denver, CO area	500.0	300-399	AC	Unknown	2018
WECC-US	Lamar - Front Range Transmission	C	Lamar, CO area	Denver, CO area	500.0	300-399	AC	Unknown	2018
WECC-US	Oneok 115 kV Project	P	Yuma County, CO	To Be Determined	20.0	100-120	AC	166.0	2012
WECC-US	Bromley-Prairie Center 115 kV Line	P	Brighton, CO	Brighton, CO	4.0	100-120	AC	166.0	2012
WECC-US	Plaza - Waverly 69-115kV conversion	P	Plaza, CO	Waverly, CO	30.5	100-120	AC	Unknown	2013
WECC-US	Big Sandy-Lincoln-Midway 230kV Line	P	Limon, CO	S. of Colorado Springs, CO	56.0	200-299	AC	Unknown	2013
WECC-US	Shiprock-Kiffen Canyon 230 kV Line	P	Shiprock, NM	La Plata County, CO	40.0	200-299	AC	613.0	2015
WECC-US	Shiprock-Kiffen Canyon 230 kV Line	P	Shiprock, NM	La Plata County, CO	40.0	200-299	AC	613.0	2015
WECC-US	Calumet-Walsenburg 230 kV Line	P	Huerfano County, CO	Pueblo, CO	7.0	200-299	AC	613.0	2015
WECC-US	San Luis Valley-Calumet 230 kV Line	P	Alamosa County, CO	Huerfano County, CO	93.0	200-299	AC	(2) 613	2017
WECC-US	San Luis Valley-Calumet 230 kV Line	P	Alamosa County, CO	Huerfano County, CO	93.0	200-299	AC	(2) 613	2017
WECC-US	Sidney-Peetz Logan 230kV Line	P	Sidney, NB	Peetz, CO	5.0	200-299	AC	Unknown	2017
WECC-US	Sidney-Peetz Logan 230kV Line	P	Sidney, NB	Peetz, CO	5.0	200-299	AC	Unknown	2017
WECC-US	Big Sandy - Calhan 230 kV	P	Limon, CO	Calhan, CO	55.0	200-299	AC	Unknown	2017
WECC-US	Big Sandy - Calhan 230 kV	P	Limon, CO	Calhan, CO	55.0	200-299	AC	Unknown	2017
WECC-US	Burlington-Wray 230 kV Line	P	Burlington, CO	Wray, CO	56.0	200-299	AC	613.0	2015
WECC-US	Calumet-Comanche 345 kV Line	P	Huerfano County, CO	Pueblo, CO	43.0	300-399	AC	(2) 1700	2015
WECC-US	Richard Lake - Waverly 115 kV Line	UC	Richard Lake CO	Wellington CO	8.0	100-120	AC	166.0	2012
WECC-US	Valley Farms-Oracle	C	Valley Farms	Oracle	39.5	100-120	AC	Unknown	2018
WECC-US	Tucson-Nogales	C	Tucson	Nogales	20.4	100-120	AC	Unknown	2020
WECC-US	Saguaro-Tucson	C	Saguaro	Tucson	35.4	100-120	AC	Unknown	2021
WECC-US	Nogales-Apache	C	Nogales	Apache	59.2	100-120	AC	Unknown	2022
WECC-US	Saguaro-Oracle	C	Saguaro	Oracle	0.0	100-120	AC	Unknown	2022
WECC-US	Coolidge-Valley Farms	C	Coolidge	Valley Farms	5.2	100-120	AC	Unknown	2015
WECC-US	ED5-Saguaro Northern	C	ED5	Saguaro	17.1	100-120	AC	Unknown	2016
WECC-US	ED5-Saguaro Southern	C	ED5	Saguaro	17.0	100-120	AC	Unknown	2016
WECC-US	Parker-Headgate Rock	C	Parker	Headgate Rock	14.0	151-199	AC	Unknown	2016
WECC-US	Headgate Rock-Bouse	C	Headgate Rock	Bouse	18.0	151-199	AC	Unknown	2016
WECC-US	Empire-ED5	P	Empire	ED5	9.2	100-120	AC	Unknown	2012
WECC-US	ED4-ED5	P	ED4	ED5	9.1	100-120	AC	Unknown	2013
WECC-US	ED4-ED2	P	ED4	ED2	9.2	100-120	AC	Unknown	2014
WECC-US	Thornton Road-Empire	UC	Casa Grande	Empire	13.2	100-120	AC	Unknown	2012
WECC-CAN	Hanna Area Reinforcement	P	28S	132S	23.0	200-299	AC	1,275.0	2012
WECC-CAN	Heartland Reinforcement	P	12S	13S	17.0	200-299	AC	754.0	2013
WECC-CAN	Hanna Area Reinforcement	P	946S	801S	4.0	200-299	AC	1,103.0	2013
WECC-CAN	Hanna Area Reinforcement	P	946S	963S	22.0	200-299	AC	1,103.0	2013
WECC-CAN	Hanna Area Reinforcement	P	650S	932S	37.0	200-299	AC	1,103.0	2013
WECC-CAN	Hanna Area Reinforcement	P	932S	959S	42.0	200-299	AC	1,103.0	2013
WECC-CAN	Hanna Area Reinforcement	P	959S	946S	54.0	200-299	AC	1,103.0	2013
WECC-CAN	South Alberta Reinforcement	P	59S	237S	150.0	200-299	AC	Unknown	2015
WECC-CAN	South Alberta Reinforcement	P	Whitla	244S	55.0	200-299	AC	1,275.0	2014
WECC-CAN	South Alberta Reinforcement	P	324S	244S	85.0	200-299	AC	1,275.0	2014
WECC-CAN	South Alberta Reinforcement	P	103S	Journault	19.0	200-299	AC	1,103.0	2016
WECC-CAN	South Alberta Reinforcement	P	491S	312S	24.0	200-299	AC	1,275.0	2016
WECC-CAN	South Alberta Reinforcement	P	312S	103S	24.0	200-299	AC	1,275.0	2016
WECC-CAN	South Alberta Reinforcement	P	Journault	Whitla	60.0	200-299	AC	1,103.0	2015
WECC-CAN	South Alberta Reinforcement	P	Journault	120S	32.0	200-299	AC	1,103.0	2014
WECC-CAN	Foothills Area Development	P	SS-65	74S	11.0	200-299	AC	Unknown	2015
WECC-CAN	Foothills Area Development	P	237S	SS-65	29.0	200-299	AC	Unknown	2015
WECC-CAN	Foothills Area Development	P	237S	42S	60.9	200-299	AC	Unknown	2017
WECC-CAN	Heartland Reinforcement	P	12S	89S	50.0	400-599	AC	3,500.0	2013
WECC-CAN	Fort McMurray Reinforcement	P	GENESEE AB	939S	304.0	400-599	AC	3,500.0	2017
WECC-CAN	Fort McMurray Reinforcement	P	939S	951S	304.0	400-599	AC	3,500.0	2017
WECC-CAN	Edmonton to Calgary Reinforcement	P	12S	28S	310.0	400-599	DC	3,000.0	2014
WECC-CAN	Edmonton to Calgary Reinforcement	P	GENESEE AB	102S	225.0	400-599	DC	3,000.0	2014
WECC-CAN	Invermere to Goldon 230 kV line	P	Invermere, BC	Kicking Horse	120.0	200-299	AC	1,357.0	2012
WECC-CAN	Vancouver City Central(2L20 & 2L44)	P	Cathedral Square	Sperling (via Mt Pleasant)	8.2	200-299	AC		2012
WECC-CAN	West End Substation	P	Horne Payne	West End	10.4	200-299	AC		2019
WECC-CAN	Metro North Reinforcement	P	Como Lake	Murrin (via Horne Payne)	26.8	200-299	AC		2018
WECC-CAN	Dawson Creek / Chetwynd(DCAT)	P	Sundance, BC	Bear Mountain, BC	60.2	200-299	AC	2,386.0	2013
WECC-CAN	Northwest Transmission Line (NTL)	P	Skeena, BC	Bob Quinn, BC	340.0	200-299	AC	3,004.0	2014
WECC-CAN	Fraser Valley W Reinforcement	P	Ingledow, BC	Mclellan (via Fleetwood)	16.0	200-299	AC		2014
WECC-CAN	5L91 (50%) Series Compensation	P	Ashton Creek, BC	Selkirk, BC	0.0	400-599	AC		2018
WECC-CAN	5L98 (50%) Series Compensation	P	Nichola, BC	Vassuax Lake, BC	0.0	400-599	AC		2018
WECC-CAN	5L5 and 5L6 (Site C to PCN)	P	Site C, BC	Peace Canyon	0.0	400-599	AC		2020

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
WECC-CAN	500 kV Line (5L83) Project	P	Nicola BC	Meridian BC	153.0	400-599	AC	3,000.0	2014
WECC-CAN	5L71 & 5L72 (50%) Series Comp.	P	Mica, BC	Nicola, BC	0.0	400-599	AC		2014
WECC-MX	La Jovita	P	La Jovita MX	Presidente Juarz MX	38.0	200-299	AC	430.0	2012
WECC-MX	Valle de Puebla	P	Valle de Puebla	Tecnologico MX	5.8	200-299	AC	388.0	2012
WECC-MX	Valle de Puebla	P	Valle de Puebla	Sanchez Taboada MX	12.3	200-299	AC	388.0	2012
WECC-MX	Parque Industrial	P	Parque Industrial	Cerro Prieto II MX	33.6	200-299	AC	388.0	2012
WECC-MX	La Jovita	P	La Jovita MX	Lomas MX	30.0	200-299	AC	430.0	2018
WECC-MX	El Cañon	P	El Cañon MX	El Ciprés MX	52.0	200-299	AC	430.0	2018
WECC-MX	La Jovita	P	La Jovita MX	El Ciprés MX	35.0	200-299	AC	430.0	2013
WECC-MX	El Centenario	P	El Centenario MX	La Rosita MX	8.0	200-299	AC	388.0	2013
WECC-MX	El Centenario	P	El Centenario MX	Sanchez Taboada MX	8.0	200-299	AC	388.0	2013
WECC-MX	La Jovita	P	La Jovita MX	La Herradura MX	50.0	200-299	AC	430.0	2015
WECC-MX	Cucapah	P	Cucapah	Mexicali MX	14.3	200-299	AC	388.0	2014
WECC-MX	Cucapah	P	Cucapah	Sanchez Taboada MX	14.3	200-299	AC	388.0	2014
WECC-MX	Cucapah	P	Cucapah	Cerro Prieto II MX	14.9	200-299	AC	388.0	2014
WECC-MX	Cucapah	P	Cucapah	La Rosita MX	20.5	200-299	AC	388.0	2014
WECC-MX	Ensenada	P	Ensenada	La Herradura MX	49.7	400-599	AC	800.0	2018

Appendix III: NERC-Wide Projected Transformer Projects

Table Notes

- Includes transformer projects that are under construction, planned, or conceptual, with in-service dates from 2012-2022, as reported by each NERC Assessment Area.

Appendix III: NERC-Wide Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
ERCOT	Wellborn Switching Sub	138	69	Sep-2013	Install (3) Breaker ring to include (2) 138 lines and (1) 138/69 auto transformer relocated from Greens Prairie
ERCOT	Mountain Top-Blanco-Devil's Hill	138	69	Dec-2012	Close the 69-kV switch (SW 458) at the Blanco substation(7482) to loop the load located at the Blanco substation. Upgrade the capacity of the 138-69-kV auto-transformer (T2) at the Devil's Hill substation(7493) from 20-MVA to 45-MVA.
ERCOT	Oran 138/69 kV autotransformer	138	69	Dec-2012	Install second 138/69 kV autotransformer
ERCOT	Cumby Switch	138	69	May-2013	Replace existing 138/69 kV autotransformer
ERCOT	Melon Creek: Install 138/69 KV Auto	138	69	Mar-2015	Construct Melon Creek substation on Airco to Rincon 138 kV line with 138/69 kV, 93 MVA, auto. Build new 69 kV line from Melon Creek to Tatton. Rebuild 69 kV line from Refugio to Tatton.
ERCOT	Whitney 2nd Auto	138	69	Oct-2012	Replace 60 MVA, 138/69 kV auto with 75 MVA auto
ERCOT	Illinois #4, Build new three breaker ring bus & add 138/69 kV auto	138	69	Feb-2012	Rebuild 69 kV line from Ft. Lancaster to Hamilton Rd. with 795 ACSS, double circuit capable as alternative to CREZ project of rebuilding Sonora to Hamilton 138 kV line
ERCOT	Lytle: Add 138/69 kV Auto	138	69	Dec-2012	Add CPS Lytle to ETT Lytle 795 ACSR 138 kV line and 93 MVA 69/138 kV autotransformer at Lytle
ERCOT	Seaton Auto	138	69	Jun-2015	Upgrade 138/69 kV auto to 100 MVA
ERCOT	Bonham Switching Station 138/69 kV autotransformer replacement	138	69	May-2018	Replace existing 138/69 kV autotransformer
ERCOT	Leon Switch #2 138/69 kV autotransformer replacement	138	69	May-2018	Replace existing 138/69 kV autotransformer
ERCOT	Pleasant Valley second 138/69 kV autotransformer	138	69	May-2019	Install second 138/69 kV autotransformer
ERCOT	Royse 138/69 kV autotransformer	138	69	May-2020	Install larger autotransformer
ERCOT	Choate Station and Autotransformer	138	69	Jan-2013	Build new Choate substation where Pawnee to Four Corners 138 kV and Kenedy to Charco 69 kV lines cross and add a 150 MVA 139/69 kV autotransformer
ERCOT	Fashing Autotransformer	138	69	Mar-2013	Expand Fashing station to have 138 kV and add a 150 MVA 138/69 kV autotransformer at Fashing.
ERCOT	Magruder: Add 138/69 kV, 187 MVA, auto, 3 breaker 138 kV ringbus, 1 69 kV lowside breaker	138	69	Sep-2014	Reconductor Victoria to North Victoria and North Victoria to Magruder 69 kV line to 1590 ACSR. Install 138/69 kV, 187 MVA, autotransformer at Magruder on the Victoria to Thomaston 138kV line.
ERCOT	Ranchito: Build 138 kV station with 138 KV Auto and Ring Bus	138	69	Dec-2017	Construct 345 kV line from LaPalma to Ranchito to South McAllen and add 345/138/69 kV substation adjacent to existing Cavazos 69 kV substation with 600 MVA 345/138 kV autotransformer
ERCOT	Pearsall auto upgrade	138	69	May-2012	Upgrade the 50 MVA138/69 kV autotransformer.
ERCOT	Laguna: Add 138/69 kV Auto	138	69	Mar-2014	Construct new 138 kV line and add tranformation at Laguna to remove contingency overloads during off-peak maintenance
ERCOT	Greens Bayou Autotransformer Upgrade	345	138	May-2013	Replace existing 400MVA Greens Bayou autotransformer A2 with 800MVA autotransformer.
ERCOT	Obrien Autotransformer Upgrade	345	138	May-2013	Replace existing 400MVA Obrien autotransformer A3 with 800MVA autotransformer.
ERCOT	Zorn Autotransformer Addition	345	138	May-2013	Add a new 345-138 kV 478 MVA autotransformer at the Zorn substation (7042).
ERCOT	Cedar Hill Switch second 345/138 kV autotransformer	345	138	May-2019	Install autotransformer
ERCOT	PH Robinson Autotransformer A3	345	138	Mar-2012	Install temporary 600MVA Autotransformer A3 at PH Robinson
ERCOT	Anna Switch 345/138 kV autotransformer replacement	345	138	May-2012	Replace #1 autotransformer
ERCOT	Southeast Nacogdoches 345/138 kV autotransformer	345	138	May-2012	Replace existing 345/138 kV autotransformer with larger autotransformer

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
ERCOT	Cagnon - Install a Third 345kV Autotransformer	345	138	Sep-2012	Install one 600 MVA autotransformer.
ERCOT	Killeen Switch	345	138	Dec-2012	Install circuit breakers and second 345/138 kV autotransformer
ERCOT	Willow Valley Switch	345	138	Jun-2013	Install 345/138 kV autotransformer
ERCOT	Forney Sw. Sta. Second 600 MVA, 345/138 kV Autotransformer	345	138	May-2014	Add second 345/138 autotransformer
ERCOT	Cagnon - Install a Fourth 345kV Autotransformer	345	138	Jun-2014	Install one 600 MVA autotransformer.
ERCOT	Hicks Switch Autotransformer	345	138	May-2015	Install 345/138 kV autotransformer
ERCOT	Collin 345/138 kV autotransformer	345	138	May-2016	Install second 345/138 kV autotransformer
ERCOT	Sargent Road 345/138 kV autotransformer	345	138	May-2016	Install second 345/138 kV autotransformer
ERCOT	Norwood Switch autotransformer	345	138	May-2016	Replace #1 345/138 kV autotransformer
ERCOT	Loma Alta 345kV station and autotransformer	345	138	May-2018	Construct a 345 substation and connect to the existing Loma Alta 138 substation.
ERCOT	Trinity Switch 345/138 kV autotransformer	345	138	May-2018	Create Trinity Switch and install a 600 MVA 345/138 kV autotransformer
ERCOT	Lavon 345/138 kV Switching Station	345	138	May-2018	Construct 345/138 kV switching station
ERCOT	North Lake 345/138 kV autotransformer	345	138	May-2018	Install a 345/138 kV autotransformer
ERCOT	Renner	345	138	May-2020	Replace existing 345/138 kV autotransformer with larger autotransformer
ERCOT	Kendall Autotransformer Addition	345	138	Jul-2012	Replace the existing 345-138 kV 478MVA autotransformer with an 672 MVA autotransformer at the Kendall substation (7150).
ERCOT	Dunlap 138/345kV Autotransformer Project	345	138	Mar-2013	Install a 138/345 kV 672 MVA autoxfmr at Dunlap, configuring a Dunlap to Lost Pines 345 kV circuit, add a new 345kV line from Dunlap to Austrop and combine 138kv Dunlap to Decker and Decker to Techridge into one single circuit bypassing Decker.
ERCOT	Frontera: Build 345 kV station with 345/138 kV	345	138	Oct-2017	Construct 345 kV line from Frontera to Del Sol
ERCOT	Ranchito, New SS with 345/138 kV autotransformer	345	138	Dec-2017	Construct 345 kV line from LaPalma to Ranchito to South McAllen and add 345/138/69 kV substation adjacent to existing Cavazos 69 kV substation with 600 MVA 345/138 kV autotransformer
ERCOT	South McAllen, new SS with 345/138 kV autotransformer	345	138	Dec-2017	Add Frontera to South McAllen 345 kV line with bundled 1590 ACSR and double circuit capable structures and 345/138 kV substations at Frontera and South McAllen
ERCOT	2nd Lewisville Auto	345	138	Mar-2012	Install (2nd) 345/138 kV autotransformer at Lewisville station
ERCOT	Jack County Auto	345	138	Jun-2013	Install 345/138 kV, 700 MVA auto at Jack County
ERCOT	Dobbin switching station	345	138	Feb-2015	Construct 345/138 kV switching station in CNP's Roans Prairie to Kuykendahl line
ERCOT	Kendall Autotransformer Replacement	345	138	Jun-2012	Replace the existing 345/138 kV 336 MVA autotransformer with an 800 MVA autotransformer at the Kendall Substation (7152).
ERCOT	Mont Belvieu Area Upgrades	345	138	May-2014	Build new 345/138kV JORDAN substation. Install new 800 MVA autotransformer.
ERCOT	Central Bluff Switch	345	138	Dec-2011	Construct 345 kV switching station with 345/138 kV autotransformer
ERCOT	North McCamey Autotransformer Addition	345	138	Jan-2014	Add two new 345-138 kV 800 MVA autotransformer at the North McCamey substation (76595).
FRCC	NO PROJECTS TO REPORT	-	-	-	No Projected Transformer Projects
MISO	Fargo, ND - St Cloud/Monticello, MN area 345 kV project	345	115	05-2013	Bison - AlexandriaSS - Waite Park - Monticello 345 ckt 1, Sum rate 2085
MISO	Rockdale-West Middleton 345 kV	345	138	06-2013	Construct a new 345/138 kV substation at Cardinal (next to the existing West Middleton sub), install a 345/138 kV 500 MVA transformer at Cardinal, construct 47.9 miles overhead 345 kV line from Albion to Cardinal/West Middleton, modifications to the existing West Middleton substation, construct a new Albion 345 kV switching station. Facility costs listed in the facility table are for the southern route.

Appendix III: NERC-Wide Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
MISO	Rockdale-West Middleton 345 kV	345	138	06-2013	Construct a new 345/138 kV substation at Cardinal (next to the existing West Middleton sub), install a 345/138 kV 500 MVA transformer at Cardinal, construct 47.9 miles overhead 345 kV line from Albion to Cardinal/West Middleton, modifications to the existing West Middleton substation, construct a new Albion 345 kV switching station. Facility costs listed in the facility table are for the southern route.
MISO	Monroe County - Council Creek 161 kV line projects	161	138	12-2014	Monroe County - Council Creek 161 kV line, Council Creek 161/138 kV transformer; Council Creek-Petenwell uprate 138 kV
MISO	Weeds Lake	345	138	12-2014	Loop the 345kV Argenta - Robinson Park 345kV circuit into a new 345/138kV EHV substation called Weeds Lake. Build 4 new (approximately 6 miles) 138kV circuits to loop the two Argenta-Milham 138kV lines into the substation.
MISO	Westwood Bk1 Limiting Equipment	345	138	06-2015	Replace 1600A 138kV breaker with 3000A to allow full xfr rating.
MISO	SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV project	345	161	12-2012	Construct Hampton Corner-North Rochester-Chester-North LaCrosse 345 kV line, North Rochester - N. Hills 161 kV line, North Rochester-Chester 161 kV line, Hampton Corner 345/161 transformer, North Rochester 354/161 transformer, North LaCrosse 345/161 transformer
MISO	SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV project	345	161	03-2014	Construct Hampton Corner-North Rochester-Chester-North LaCrosse 345 kV line, North Rochester - N. Hills 161 kV line, North Rochester-Chester 161 kV line, Hampton Corner 345/161 transformer, North Rochester 354/161 transformer, North LaCrosse 345/161 transformer
MISO	G519 - Mesaba	230	115	07-2014	Network Upgrades associated with 600 MW coal gasification generating facility at the propsoed Mesaba generating station. There is a G477 alternate site which is not described here.
MISO	Candidate MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	345	115	11-2013	Brookings Cty-Lyon Cty (Single Ckt 345 kV); Lyon Cty-Cedar Mountain-Helena (Double Ckt 345 kV); Helena-Chub Lake-Hampton Corner (Single Ckt 345 kV); Lyon Cty-Hazel (Single Ckt 345 kV); Hazel-Minnesota Valley (Single Ckt 345 kV, initially operate at 230 kV); Cedar Mountain-Franklin (Single Ckt 115 kV)
MISO	Candidate MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	345	115	04-2014	Brookings Cty-Lyon Cty (Single Ckt 345 kV); Lyon Cty-Cedar Mountain-Helena (Double Ckt 345 kV); Helena-Chub Lake-Hampton Corner (Single Ckt 345 kV); Lyon Cty-Hazel (Single Ckt 345 kV); Hazel-Minnesota Valley (Single Ckt 345 kV, initially operate at 230 kV); Cedar Mountain-Franklin (Single Ckt 115 kV)
MISO	Candidate MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	345	230	12-2014	Brookings Cty-Lyon Cty (Single Ckt 345 kV); Lyon Cty-Cedar Mountain-Helena (Double Ckt 345 kV); Helena-Chub Lake-Hampton Corner (Single Ckt 345 kV); Lyon Cty-Hazel (Single Ckt 345 kV); Hazel-Minnesota Valley (Single Ckt 345 kV, initially operate at 230 kV); Cedar Mountain-Franklin (Single Ckt 115 kV)
MISO	Candidate MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	345	115	07-2013	Brookings Cty-Lyon Cty (Single Ckt 345 kV); Lyon Cty-Cedar Mountain-Helena (Double Ckt 345 kV); Helena-Chub Lake-Hampton Corner (Single Ckt 345 kV); Lyon Cty-Hazel (Single Ckt 345 kV); Hazel-Minnesota Valley (Single Ckt 345 kV, initially operate at 230 kV); Cedar Mountain-Franklin (Single Ckt 115 kV)
MISO	Replace Arcadian 345/138 kV transformer	345	138	06-2020	Replace Arcadian 345/138 kV transformer #3 with a 500 MVA transformer.
MISO	Hazleton - Salem 345 kV line with a 2nd Salem 345/161 kV 448 MVA transformer.	345	161	05-2013	Build a new Hazleton - Salem 345 kV line. Expand the Hazleton 345kV bus to a 5 position ring and expand the Salem 345kV ring to allow for a 2nd Salem 345/161 kV 448 MVA transformer. (option 1) The route will follow the existing Hazleton-Dundee-Liberty-Lore 161kV route.
MISO	Coffey (formerly Lewis Fields) 161 kV substation which taps the SwampFX - Coggon 115 kV line	161	115	12-2014	Construct a new Coffey (formerly Lewis Fields) substation with 161/115kV transformer & a single 161kV line to feed to Hiawatha and 2 115kV lines to Swamp Fox & Coggon. Future configuration will allow for a single 115kV line to feed to Swamp Fox and 2 161kV lines to Hiawatha & Coggon. A new ~9 mile 161 kV line from Hiawatha to Coffeybe built.
MISO	Coffey (formerly Lewis Fields) 161 kV substation which taps the SwampFX - Coggon 115 kV line	161	115	12-2014	Construct a new Coffey (formerly Lewis Fields) substation with 161/115kV transformer & a single 161kV line to feed to Hiawatha and 2 115kV lines to Swamp Fox & Coggon. Future configuration will allow for a single 115kV line to feed to Swamp Fox and 2 161kV lines to Hiawatha & Coggon. A new ~9 mile 161 kV line from Hiawatha to Coffeybe built.
MISO	Build a new 345 kV Morgan Valley (Beverly) substation which taps the Arnold -Tiffin 345 kV line	345	161	12-2014	Build a new 345 kV Morgan Valley (Beverly) Tap substation and tapped to 345 kV line Arnold - Tiffin at 40% distance away from Arnold. Add a new 335 MVA 345/161 kV transformer and build a new 161 kV line connecting the new substation to Beverly 161 kV bus. Tap Arnold-Fairfax 161kV line for in and out feeds from Morgan Valley
MISO	RTU / SCADA Re-direction Program	345	138	06-2013	Install and/or upgrade RTU's and SCADA points throughout system
MISO	Qualitech 345/138KV Transformer and breakers	345	138	06-2013	Qualitech Sub- Install one 345/138kv, 300Mva Xtr and 2-345kv Bkrs and 1-138kv Bkr to provide second 138kv source to proposed Hendricks Co 138kv system

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
MISO	Hancock 230/120kV Transformer	230	120	12-2015	Cut the Wixom-Quaker 230kV circuit into Hancock Station, install a 230/120kV transformer.
MISO	Petersburg 345/138kV East and West Autotransformers and 345 kV breaker	345	138	06-2013	Replace and upgrade existing East and West 345/138kV autotransformer at Petersburg Substation. Add 345kV breaker.
MISO	South Bloomington - Install new 560 MVA 345 /138 Xfmr	345	138	06-2015	South Bloomington Area 345/138 kV Substation - Install 345/138 kV, 560 MVA Transformer. Extend new 345 kV line approximately 5 miles from Brokaw Substation to South Bloomington Substation. Install 1-138 kV PCB at South Bloomington Substation, and 2-345 kV PCB's at Brokaw Substation
MISO	North Mankato 115 kV project	345	115	04-2013	1) New 345/115 kV TR at the proposed Helena 345 kV switching station. 2) New 115 kV line from Helena - St. Thomas. 3) New 115/69 kV substation near St. Thomas. 4) New 69 kV switchig station at Lesueur Tap.
MISO	Proposed MVP Portfolio 1 - Reynolds to Greentown 765 kV line	765	345	06-2018	Reynolds to Greentown 765 kV line
MISO	Proposed MVP Portfolio 1 - Ellendale to Big Stone South	345	230	12-2019	Big Stone to Ellendale 345 kV line
MISO	Proposed MVP Portfolio 1 - Big Stone South to Brookings	345	230	12-2017	Brookings to Big Stone 345 kV line (double ckt capable)
MISO	Proposed MVP Portfolio 1 - Big Stone South to Brookings	345	230	12-2017	Brookings to Big Stone 345 kV line (double ckt capable)
MISO	Proposed MVP Portfolio 1 - Big Stone South to Brookings	345	230	12-2015	Brookings to Big Stone 345 kV line (double ckt capable)
MISO	Proposed MVP Portfolio 1 - Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	345	138	11-2018	Pana to Mt. Zion to Kansas to Sugar Creek 345 kV line. Install transformers at Mt. Zion and Kansas
MISO	Proposed MVP Portfolio 1 - Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	345	138	11-2018	Pana to Mt. Zion to Kansas to Sugar Creek 345 kV line. Install transformers at Mt. Zion and Kansas
MISO	Proposed MVP Portfolio 1 - Adair - Ottumwa 345	345	161	11-2018	Adair Substation - New 560 MVA, 345/161 kV Transformer. New 71 mile 345 kV line from Adair to Ottumwa with 3000 A summer emergency capability
MISO	Proposed MVP Portfolio 1 - Adair - Ottumwa 345	345	161	06-2017	Adair Substation - New 560 MVA, 345/161 kV Transformer. New 71 mile 345 kV line from Adair to Ottumwa with 3000 A summer emergency capability
MISO	Nortwest Cape Area 345/161 kV Substation	345	161	06-2016	Install 560 MVA, 345/161 kV Transformer. Provide 345 kV supply from 11 mile 345 kV line extension from Lutesville Substation
MISO	New 345kV Supply at Fargo Substation	345	138	12-2016	Tap existing 345kV line from Duck Creek to Tazewell and create new Maple Ridge Substation ($6.5M) Build a new supply line to the Fargo Substation by extending 20 miles of 345kV from the new Maple Ridge Substation ($50.1M) Create Fargo Station and install 560 MVA 345/138kV Transformer ($9.4M)
MISO	Sag clearance 2012	345	138	12-2012	Identify and remediate inherent sag limitations on heavily loaded METC trasmission lines throughout the system.
MISO	Breaker Replacement Program 2012	345	120	12-2012	Replace defective, damaged, or over dutied breakers throughout system.
MISO	NERC Relay Loadability Compliance 2012	345	120	12-2012	Upgrade relays throughout system
MISO	Potential Device Replacement 2012	345	120	12-2012	Replace aging potential devices
MISO	Relay Betterment Program 2012	345	120	12-2012	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.
MISO	Sub 39: Second 345-161 kV Xfmr	345	161	06-2016	Add a second 345-161 kV xfmr. Expand 345 kV and 161 kV buses.

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
MISO	Sidney Transformer Addition	345	138	06-2013	Sidney 345/138 kV Substation - Install a second 345/138kV, 560 MVA Transformer and establish 345 kV ring bus
MISO	Baldwin-Grand Tower-N.W. Cape 345 kV Line	345	138	12-2018	New 69 mile, single-circuit line (possible double circuit), 3000 A SE capability (Baldwin-Grand Tower - 45 miles; Grand Tower-N.W. Cape - 24 miles). Grand Tower 345/138 kV Substation - 1-560 MVA transformer, 345 kV Ring bus
MISO	Proposed MVP Portfolio 1 - Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	345	138	11-2016	Palmyra Tap to Quincy to Meredosia to Ipava 345 line and Meredosia to Pawnee 345 kV line. Install additional transformers at Quincy, Meredosia and Pawnee.
MISO	Proposed MVP Portfolio 1 - Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	345	138	11-2017	Palmyra Tap to Quincy to Meredosia to Ipava 345 line and Meredosia to Pawnee 345 kV line. Install additional transformers at Quincy, Meredosia and Pawnee.
MISO	Proposed MVP Portfolio 1 - Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	345	138	11-2016	Palmyra Tap to Quincy to Meredosia to Ipava 345 line and Meredosia to Pawnee 345 kV line. Install additional transformers at Quincy, Meredosia and Pawnee.
MISO	Proposed MVP Portfolio 1 - Fargo-Galesburg-Oak Grove 345 kV Line	345	138	12-2016	Fargo-Galesburg-Oak Grove 345 kV Line - New 70 mile, 3000 A summer emergency capability line. 345 kV PCBs: 3-Fargo, 1-Oak Grove. 3-Galesburg. 560 MVA xfmr at Galesburg
MISO	Proposed MVP Portfolio 1 - N LaCrosse-N Madison-Cardinal - Dubuque area 345-kV	345	138	12-2018	N LaCrosse- N Madison - Cardinal 345-kV & Dubuque County - Cardinal 345 kV line and Transformers needed for stepdown
MISO	Proposed MVP Portfolio 1 - N LaCrosse-N Madison-Cardinal - Dubuque area 345-kV	345	138	12-2018	N LaCrosse- N Madison - Cardinal 345-kV & Dubuque County - Cardinal 345 kV line and Transformers needed for stepdown
MISO	Proposed MVP Portfolio 1 - N LaCrosse-N Madison-Cardinal - Dubuque area 345-kV	345	138	12-2018	N LaCrosse- N Madison - Cardinal 345-kV & Dubuque County - Cardinal 345 kV line and Transformers needed for stepdown
MISO	Proposed MVP Portfolio 1 - N LaCrosse-N Madison-Cardinal - Dubuque area 345-kV line	345	161	12-2018	N LaCrosse- N Madison - Cardinal 345-kV & Dubuque County - Cardinal 345 kV line and Transformers needed for stepdown
MISO	Cass Lake -Nary-Helga -Bemidji 115	230	115	12-2012	Capacity upgrade: Cass Lake-Bemidji 115 kV
MISO	Proposed MVP Portfolio 1 - Michigan Thumb Wind Zone	345	120	12-2013	The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station, two 345 kV circuits will extend down the east side of the Thum to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the site that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area.
Assessment	Transformer Project	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description

Area	Name				
MISO	Proposed MVP Portfolio 1 - Michigan Thumb Wind Zone	345	120	12-2013	The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station station, two 345 kV circuits will extend down the east side of the Thum to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the site that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area.
MISO	Proposed MVP Portfolio 1 - Michigan Thumb Wind Zone	345	120	12-2013	The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station station, two 345 kV circuits will extend down the east side of the Thum to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the site that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area.
MISO	Proposed MVP Portfolio 1 - Michigan Thumb Wind Zone	345	120	12-2015	The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station station, two 345 kV circuits will extend down the east side of the Thum to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the site that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area.
MISO	Proposed MVP Portfolio 1 - Pawnee to Pana - 345 kV Line	345	138	11-2018	Pawnee to Pana 345 kV line including additional transformer at Pana

Assessment	Transformer Project	High-Side	Low-Side	In-Service	Description

Area	Name	Voltage(kV)	Voltage(kV)	(Month-Year)	
MISO	Proposed MVP Portfolio 1: Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien Coutny - Kossuth County - Webster 345 kV line	345	161	12-2015	New 345 kV line from Lakefield Junction to Kossuth County via Winnebago and Winco and a new 345 kV line from Obrien County to Webster via Kossuth County. Includes 161 kV rebuild as underbuild along portions of the route.
MISO	Proposed MVP Portfolio 1: Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien Coutny - Kossuth County - Webster 345 kV line	345	161	12-2015	New 345 kV line from Lakefield Junction to Kossuth County via Winnebago and Winco and a new 345 kV line from Obrien County to Webster via Kossuth County. Includes 161 kV rebuild as underbuild along portions of the route.
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Chisago County 2nd 345/115 kV transformer	345	115	06-2014	This project is to install a 2nd 345/115 kV transformer at Chisago County
MISO	Noblesville Sta. 138kV Brkrs and 345kV Ckt Sws	345	138	12-2012	Noblesville Gen. Sta. - Replace 138KV OB OCB: 138TR, 13869-9, 138230-7, 13886 and Circuit Switchers: 345230-11, 34519.
MISO	Prairie 3rd transformer	230	115	06-2014	This project is to install a 3rd 230/115 kV transformer at Prairie substation
MISO	Buffalo - Casselton 115 kV Line	345	115	11-2014	Construct 16 mile 115 kV line from Buffalo - Casselton (ND); Replace Buffalo 345/115 kV Transformer; Rebuild portion of Sheyenne - Mapleton 115 kV Line
Manitoba Hydro	Brandon Cornwallis	230	115	Jun-2013	120/160/176 MVA
Manitoba Hydro	Rockwood	230	115	Sep-2015	150/200/250 MVA
Manitoba Hydro	Riel	500	230	Nov-2015	720/960/1200 MVA; Associated with Bipole 3 / Conawapa project
Manitoba Hydro	Riel	500	230	Oct-2019	720/960/1200 MVA; Associated with 5th Manitoba - US tie project
Manitoba Hydro	Brandon Cornwallis	230	115	Jun-2013	120/160/176 MVA
Manitoba Hydro	Rockwood	230	115	Sep-2015	150/200/250 MVA
Manitoba Hydro	Riel	500	230	Nov-2015	720/960/1200 MVA; Associated with Bipole 3 / Conawapa project
Manitoba Hydro	Riel	500	230	Oct-2019	720/960/1200 MVA; Associated with 5th Manitoba - US tie project
Manitoba Hydro	Transcona	230	66	Dec-2012	
Manitoba Hydro	Transcona	230	66	Dec-2012	
Manitoba Hydro	Stanley	230	66	Oct-2012	
Manitoba Hydro	Neepawa	230	66	Dec-2012	
MAPP	Lelands Olds 345/230 replacement	345	230	Oct-2012	Replace 250MVA unit with 600MVA unit.
MAPP	Charlie Creek 345/230 #1	345	230	Jun-2012	Terminal for WAPA CCR-Williston 230 line.

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
MAPP	Charlie Creek 345/230 #2	345	230	Dec-2014	Add 2nd unit .
MAPP	Blaisdell 230/115	230	115	Jun-2012	Load serving substation.
MAPP	Wheelock 230/115	230	115	Jun-2013	Load serving substation.
MAPP	Williston 345/230	345	230	Jan-2016	Part of AVS-Neset 345 project.
MAPP	Neset 345/230	345	230	Jan-2016	Part of AVS-Neset 345 project.
MAPP	Center 345/230 kV Transformer 2	345	230	Oct-2012	360/480/600/672 MVA ONAN/ONAF/ODAF RATINGS
MAPP	Prairie 345/230 kV Transformer 1	345	230	Oct-2011	360/480/600/672 MVA ONAN/ONAF/ODAF RATINGS
MAPP	Prairie 345/230 kV Transformer 2	345	230	Oct-2012	180 MVA RATING - MOVED FROM CENTER
MAPP	Appledorn	230	69	Nov-2012	
MAPP	Watford City	230	69	Jun-2012	removed 115/69 xfmr
MAPP	Elliot	115	69	Apr-2012	
MAPP	New Underwood	230	115	Jun-2013	
MAPP	Belfield	345	230	Nov-2012	replacing with relocated xfmr
MAPP	Oahe	230	115	Nov-2013	Date not firm, replacement
MAPP	Bismarck kV8A	230	115	Jun-2012	Date not firm, replacement
MAPP	Bismarck kV3A	230	115	May-2013	Date not firm, replacement
MAPP	Creston	161	69	Jun-2013	replacement
MAPP	Sioux Falls (2)	230	115	Apr-2014	replacement
SaskPower	Tantallon Area Reinforcement	230	138	Dec-2012	Planned addition of 2x300 MVA auto-transformer.
SaskPower	Fleet Street Area Reinforcment	230	138	Dec-2012	Planned addition of 2x300 MVA auto-transformer.
SaskPower	Boundary Dam Area Reinforcement	230	138	Dec-2013	Planned addition of 2x350 MVA auto-transformer.
SaskPower	Condie Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 225 MVA auto-transformer.
SaskPower	Regina Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 200 MVA auto-transformer.
SaskPower	Pasqua Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 350 MVA auto-transformer.
SaskPower	Brada Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 150 MVA auto-transformer.
SaskPower	Wolverine Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 200 MVA auto-transformer.
SaskPower	Lloydminster Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 150 MVA auto-transformer.
Maritimes	NO PROJECTS TO REPORT	-	-	-	-
New England	2nd Deerfield Autotransformer	345	115	Dec-2012	Under Construction
New England	NEEWS - GSRP Project - Agawam	345	115	Dec-2013	Under Construction
New England	NEEWS - GSRP Project - Agawam	345	115	Dec-2013	Under Construction
New England	NEEWS - GSRP Project - North Bloomfield	345	115	Dec-2013	Under Construction
New England	NEEWS - CCRP Project - Frost Bridge	345	115	Dec-2017	Planned
New England	MPRP - Albion Rd - Larabee Rd	345	115	Jan-2013	Planned
New England	MPRP - Maguire Rd	345	115	Nov-2013	Planned
New England	Lower South East Massachusetts Upgrades	345	115	Dec-2012	Planned
New England	Greater Boston - North, South, Central - Woburn	345	115	Dec-2015	Concept
New England	Greater Boston - North, South, Central - Sudbury	230	115	Unknown	Concept
New England	Central/Western MA Upgrades Bear Swamp	230	115	Dec-2015	Planned

Appendix III: NERC-Wide Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
New England	Auburn Area Transmission Upgrades - Auburn	345	115	Jun-2013	Planned
New England	Keene Rd	345	115	Dec-2011	Under Construction
New England	Pittsfield/Greenfield Project - Northfield	345	115	Dec-2014	Planned
New England	Greater Boston - North, South, Central - Sudbury	230	115	Dec-2014	Concept
New England	Greater Boston - North, South, Central - Mystic	345	115	Dec-2015	Concept
New England	Northern NH Solution - Littleton	230	115	Dec-2016	Planned
New England	Northern NH Solution - Eagle	345	115	Dec-2016	Planned
New York	Linden VFT	345	345	Unknown	Uprate
New York	Astoria Annex	345	138	Jun-2012	
New York	Wood Street	345	115	Jun-2016	
New York	Coopers Corners	345	115	Jun-2016	
New York	Fraser	345	115	Jun-2016	
New York	Gardenville	345	115	Jun-2017	
Ontario	Oshawa Area TS	500	230	Dec-2016	Conceptual
Ontario	Milton TS	500	230	Dec-2016	Conceptual
Ontario	Bout-de-l'Ile T11	735	315	Dec-2013	
Ontario	Bout-de-l'Ile T12	735	315	Dec-2013	
Québec	Bout-de-l'Ile T11	735	315	Dec-2013	
Québec	Bout-de-l'Ile T12	735	315	Dec-2013	
Québec	Pierre-Le Gardeur T1	315	120	Dec-2014	
Québec	Pierre-Le Gardeur T2	315	120	Dec-2014	
Québec	Saguenay 735/161kV T4	735	161	Dec-2014	
Québec	Arnaud 315/161 kV	315	161	Dec-2014	Saguenay 735/161kV T4
Québec	Figuery 315/120 kV	315	120	Dec-2014	Figuery 315/120 kV T4
Québec	Romaine-1 switching	315	161	Dec-2016	Romaine-1 switching station
Québec	Arnaud-2 T1	735	315	Dec-2018	
Québec	Arnaud-2 T2	735	315	Dec-2018	
Québec	Duchemin T1	735	315	Dec-2018	
Québec	Duchemin T2	735	315	Dec-2018	
Québec	Poularies T1	315	120	Dec-2018	
Québec	Poularies T2	315	120	Dec-2018	
PJM	North Fork	345	138	06-2014	Construct new 345/138 kV station in Marquis - Bixby 345 kV
PJM	Canton Central	345	138	06-2014	Install new 345/138 kV T-3,b1034.3
PJM	Sullivan	765	345	06-2015	Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station, b1465.1
PJM	Baker	765	345	06-2015	Add an additional 765/345 kV transformer at Baker Station, b1495
PJM	Sorenson	765	345	06-2015	Build a Sorenson 765/345 kV transformer,b1659
PJM	Cloverdale	765	500	03-2015	Install a 765/500 kV transformer at Cloverdale, b1660
PJM	Jackson's Ferry	765	138	06-2015	Install a new 765/138 transformer, 6 new 138 kV breakers at Jackson's Ferry, b1663
PJM	Allen	345	138	06-2016	Expand the Allen station by installing a second 345/138 kV transformer, b1818
PJM	Kanawha River	345	138	09-2016	Add second 345/138 kV transformer at Kanawha River Station, s0358
PJM	Waugh Chapel	230	115	06-2012	Install 4th 230/115 Transformer b0474
PJM	New Substation next to Waukegan Generating Station	345	138	06-2014	Sta 16 Waukegan - Install one of two new 345/138kV transformers at the new 345kV next to present Waukegan generating station
PJM	New Substation next to Waukegan Generating Station	345	138	06-2014	Sta 16 Waukegan - Install two of two new 345/138kV transformers at the new 345kV next to present Waukegan generating station
PJM	Lisle	345	138	06-2014	Install 4th 345/138kV autotransformer
PJM	Plano	345	138	06-2014	Install 1st 345/138kV autotransformer,b0661
PJM	New auto installed at TSS 86 Davis Creek	345	138	06-2015	Install third auto transformer at TSS 86 Davis Creek substation
PJM	New auto installed at TSS 120 Lombard	345	138	06-2016	Install third auto transformer at TSS 120 Lombard substation
PJM	Bath	345	138	06-2015	Install 2nd 345/138kV transformer
PJM	West Milton	345	138	06-2015	Install 2nd 345/138kV transformer
PJM	Shelby	345	138	06-2014	Install 2nd 345/138kV transformer
PJM	Qualitech	345	138	06-2013	New Substation

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
PJM	New Reynolds	765	345	08-2018	New Transformer
PJM	Crescent	345	138	06-2014	Add 3rd 345/138 kV Autotransformer, s0168
PJM	Logans Ferry	345	138	12-2012	New Logans Ferry 345kV substation with 345/138kV autotransformer, toi334.3
PJM	Collier	345	138	06-2013	Install a No. 3 345/138 kV autotransformer at the Collier substation
PJM	Steele	230	138	06-2013	3rd Transformer, b0725
PJM	Harmony	230	138	06-2013	2nd Transformer, b0733
PJM	Loretto	230	138	06-2017	2nd Transformer, b0753
PJM	Welton Spring	765	500	06-2014	new substation - Suspended
PJM	Kemptown	765	500	06-2014	new substation - Suspended
PJM	502 Junction	500	138	12-2013	First Transformer
PJM	Cranberry	500	138	06-2012	New Sub - 333/448/560 MVA transformer #1
PJM	Cranberry	500	138	06-2012	New Sub - 333/448/560 MVA transformer #2
PJM	Fulton	345	138	06-2013	New Sub - 180/240/336 MVA Transformer
PJM	Hayes	345	138	06-2014	New Sub - 269/358/448 MVA transformer
PJM	Chamberlin	345	138	06-2016	Add 2nd transformer - 240/320/400 MVA
PJM	Raritan River	230	115	06-2013	Second Transformer
PJM	Petersburg	345	138	12-2012	Replace existing 150 MVA transformer with 300MVA unit
PJM	Rapson 1	345	120	12-2013	Thumb Project
PJM	Rapson 2	345	120	12-2013	Thumb Project
PJM	Banner	345	120	12-2015	Thumb Project
PJM	Bunce Creek	220	220	04-2012	Replace PAR with 800MVA (Summer Normal) 2 PARS in Series at Bunce Creek.
PJM	Keystone	345	230	06-2015	0
PJM	Pere Marquette	345	230	06-2015	0
PJM	Weeds Lake	345	138	06-2013	0
PJM	Chichester	230	138	04-2012	Add 2nd transformer tied directly in parallel to existing transformer. Ratings are for the transformer facility with both transformers in parallel.
PJM	Waneeta	230	138	06-2016	Install 2nd Waneeta Transformer
PJM	Brighton	500	230	06-2012	Replace Existing Transformer
PJM	Burches Hill	500	230	06-2013	3rd Transformer
PJM	Benning	230	115	06-2012	New 115kV Station at Benning - there are 2 trs at this sub - TR 13 ratings shown
PJM	Benning	230	115	06-2012	New 115kV Station at Benning - there are 2 trs at this sub - TR 14 ratings shown
PJM	Lackawanna	500	230	06-2015	In-service date changed; 750 MVA nameplate. #3
PJM	Lackawanna	500	230	06-2015	In-service date changed; 750 MVA nameplate. #4
PJM	Lackawanna	230	138	12-2017	(New 230-138 kV Substation - Add transformer #5) (336 MVA Nameplate)
PJM	Lackawanna	230	138	12-2017	(New 230-138 kV Substation - Add transformer #6) (336 MVA Nameplate)
PJM	Elroy	500	138	06-2012	Install a second Elroy 500/138 kV transformer,b0614.1
PJM	Jenkins	230	138	12-2017	(New 230-138 kV Substation - Add transformer #5) (336 MVA Nameplate)
PJM	Jenkins	230	138	12-2017	(New 230-138 kV Substation - Add transformer #6) (336 MVA Nameplate)
PJM	Breinigsville	500	138	06-2015	New 500-138 kV Sub - Add Transformer #1 (336 MVA)
PJM	Monroe	230	138	12-2014	Add 2nd 230/138 kV Transformer (336 MVA)
PJM	North Lancaster	500	230	06-2017	750 MVA nameplate.(New 500-230 kV Substation - Add transformer #1)
PJM	Roseland	500	230	06-2012	First Transformer, b0489.4
PJM	Roseland	500	230	06-2012	Second Transformer, b0489.4
PJM	Bergen	230	138	06-2014	Install 230/138 kV transformer at Bergen substation
SERC-E	Horse Gap to Watauga Relocation	230	99	Dec-2020	Planned/Move three single phase transformers from Horse Gap Substation to new Watauga 230 kV Substation.
SERC-E	West end 230 kV Transformers	230	115	Jun-2012	Under Construction/Replace existing 200 MVA transformers with new 300 MVA transformers
SERC-E	Folkstone 230 kV Substation	230	115	Jun-2013	Under Construction/Install 1-200 MVA 230/115 kV transformer
SERC-E	Selma 230/115 kV Transformer	230	115	Jun-2013	Conceptual/Replace exsiting 200 MVA with a 300 MVA transformer
SERC-E	Mt. Olive 230 kV substation	230	115	Dec-2011	Complete/Install 1-200MVA 230/115 kV Transformer
SERC-E	Fayetteville 230/115 kV Transformer	230	115	Jun-2014	Conceptual/Replace both 200 MVA transformer with 300 MVA banks.
SERC-E	Falls 230/115 kV Transformer	230	115	Jun-2016	Planned/Add 2nd 230/115 kV 300MVA transformer
SERC-E	Orangeburg	230	115	Dec-2012	Under Construction/New station under construction
SERC-E	Pomaria	230	99	Jun-2013	Planned/approval is pending
SERC-E	Purrysburg	230	115	Dec-2014	Conceptual/future substation
SERC-E	Bucksville	230	115	Jun-2014	Conceptual/future substation
SERC-E	Wassamassaw	230	115	Jun-2017	Conceptual/future substation
SERC-E	Winnsboro	230	99	Sep-2013	Planned/associated with nuclear integration
SERC-E	Richburg	230	99	Jun-2014	Planned/associated with nuclear integration
SERC-E	Sandy Run	230	115	Jun-2015	Conceptual/associated with nuclear integration
SERC-E	St. George	230	115	Apr-2018	Conceptual/associated with nuclear integration

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
SERC-E	Varnville	230	115	May-2019	Conceptual/associated with nuclear integration
SERC-E	Lake Murray 230/115kV #2	230	115	May-2013	Planned/Add 2nd 336 MVA transformer
SERC-E	Lake Murray 230/115kV #3	230	115	Dec-2015	Cancelled/Add 3rd 336MVA transformer
SERC-E	CIP 230/115kV #2	230	115	May-2020	Planned/Add 2nd 336MVA transformer
SERC-E	Denny Terrace 230/115kV #3	230	115	Dec-2015	Cancelled/Add 3rd 336MVA transformer
SERC-E	Ritter 230/115kV	230	115	Feb-2011	Complete/Construction 336MVA Substation
SERC-E	Graniteville 230/115kV #3	230	115	May-2012	Under Construction/Add 3rd 336MVA transformer
SERC-E	Carolina Forest	230	115	Jun-2012	Under Construction
SERC-E	Saluda River 230/115 kV	230	115	May-2015	Planned/Construct 230/115 kV 336 MVA Autotransformer
SERC-E	Cainhoy 230/115kV	230	115	May-2014	Planned/Construct 230/115 kV 336 MVA Autotransformer
SERC-E	Raeford 230/115 kv transformers, replace existing	230	115	Jun-2018	Planned/Replace two existing 200 MVA with 300 MVA transformers
SERC-N	4th Middletown 345/138	345	138	Dec-2013	Planned/Install 4th 345/138kV transformer at Middletown
SERC-N	Battlefield (NES)	161	99	Jun-2013	Planned/Add 161:69kV 200 MVA transformer to Battlefield substation
SERC-N	Clay, MS	500	161	Jun-2012	Under Construction/Install four single phase 500-161 kV transformers
SERC-N	Montgomery, TN	500	161	Jun-2013	Under Construction/Install three, single phase 500-161 kV transformers
SERC-N	Houston Levee sub 73 - Add 3rd Bank (MLGW)	161	99	Unknown	Under Construction/Add 3rd bank to existing substation
SERC-N	Lakeland Sub 85-Add 3rd bank (MLGW)	161	99	Dec-2012	Planned/Add 3rd bank to existing substation
SERC-N	34645 replacement (MLGW)	161	115	Unknown	Under Construction/replacement due to in-service failure (replacement has higher rating)
SERC-N	2nd Brown North 345/138kV	345	138	May-2015	Conceptual/Add a 2nd Brown North 345/138kV Transformer
SERC-N	Matanzas 161/138kV #1	161	138	Mar-2013	Planned/New Matanzas #1 161/138kV Transformer
SERC-N	Matanzas 161/138kV #2	161	138	Mar-2013	Planned/Add Matanzas #2 161/138kV Transformer
SERC-N	Jasper	345	161	Jun-2012	Planned/Planned
SERC-N	Barnett	345	161	Jun-2016	Planned/Planned
SERC-N	Wheaton	345	161	Jun-2015	Planned/Planned
SERC-N	Enon	345	161	Jun-2016	Planned/Planned
SERC-N	Thomas Hill #2	345	161	Jun-2013	Planned/Planned
SERC-SE	Bonaire	500	230	Dec-2012	Under Construction/Spare Single Phase Unit
SERC-SE	Hopewell	230	115	Jun-2015	Cancelled
SERC-SE	Sharon Springs	230	115	Jun-2018	Planned/New Substation
SERC-SE	East Social Circle	230	115	Jun-2014	Cancelled/Second transformer
SERC-SE	East Walton	500	230	Jun-2017	Planned/New substation
SERC-SE	Dresden	500	230	May-2014	Under Construction/New Substation
SERC-SE	Turf Club	230	115	May-2022	Indefinitely Postponed/Add transformation at Turf Club
SERC-SE	South Bessemer AUTO #2	230	115	May-2022	Indefinitely Postponed/Install second auto at South Bessemer; No longer needed within planning horizon
SERC-SE	Holt TS - Tuscaloosa TS AutoBank	230	115	May-2011	Complete/Install 230/115kV AutoBank at Tuscaloosa TS
SERC-SE	Greene County AutoBank	230	115	May-2013	Planned/Add 400MVA 230/115kV Autobank#2 at Plant Greene County
SERC-SE	South Duncanville AutoBank	230	115	May-2015	Cancelled/Add 400MVA 230/115kV Autobank at South Duncanville
SERC-SE	Farley 500/230kV #1 & #2 Autos	500	230	May-2019	Planned/Replace lowside equipment to achieve higher rating; No longer needed until 2019
SERC-SE	North Opelika Bank #2	230	115	May-2022	Indefinitely Postponed/Install second auto at North Opelika; No longer needed in planning horizon
SERC-SE	Autaugaville 500/230kV Auto	500	230	Jun-2012	Planned/Install new auto at Autaugaville 500 kV sub
SERC-SE	County Line Rd Bank #2	230	115	May-2014	Planned/Install second auto at County Line Road
SERC-SE	Silverhill	230	115	Jun-2021	Planned/Install a third autobank (400MVA unit)
SERC-SE	Middle Fork 500/230 kV Project	500	230	Unknown	Indefinitely Postponed/New 2016 MVA auto addition; Postponed
SERC-SE	Gainesville #2 230/115 kV Bank B	230	115	Jun-2015	Cancelled/Bundle LS jumpers and main bus, and raise the relay settings on the LSBUOC to allow for the Bank bonus rating of 339 MVA.

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
SERC-SE	Gainesville #2 230/115kV Bank C	230	115	Jun-2018	Indefinitely Postponed/Replace the existing autobank with a 400 MVA autobank.
SERC-SE	Gainesville #2 230/115 kV Bank B	230	115	Jun-2018	Indefinitely Postponed/Replace the existing autobank with a 400 MVA autobank.
SERC-SE	O'Hara 500/230 - kV Tfm#2 Addition	500	230	Unknown	Indefinitely Postponed/Add a second 2000 MVA, 500/230-kV tfm. at O'Hara
SERC-SE	South Metro Atlanta Project Phase-3	230	115	Jun-2018	Planned/Install 1- 400 MVA Tfm. at McDonough Primary substation
SERC-SE	Corn Crib 230/115 kV Project	230	115	Jun-2018	Planned/New 230/115-kV substation with a 300MVA bank
SERC-SE	Offerman Third 230/115 kV Transformer	230	115	Jun-2019	Cancelled/140 MVA
SERC-SE	S. Macon 230/115kV TFM Replacement	230	115	Unknown	Indefinitely Postponed/Replace existing autobanks w/ 400MVA autobanks
SERC-SE	Snellville 230/115 kV Transformer	230	115	May-2016	Indefinitely Postponed/Replace 1600A low-side breaker with 2000A breaker
SERC-SE	Roswell 230/115 kV Transformer Project	230	115	May-2018	Indefinitely Postponed/Install a 230/115kV transformer in the Roswell substation
SERC-SE	Scottdale 230/115kV Transformer	230	115	Unknown	Indefinitely Postponed/Add a 2nd 230/115kV transformer at Scottdale
SERC-SE	Plant McDon. Network Impvmts-P'tree Tfm. Removal	230	115	May-2013	Planned/Plant McDon. Network Impvmts-P'tree Tfm. Removal
SERC-SE	East Carrollton 230/115kV transformer	230	115	Unknown	Indefinitely Postponed/New 230/115-kV substation with a 300MVA bank
SERC-SE	Factory Shoals 230/115kV transformer	230	115	May-2011	Complete/New 230/115-kV substation with a 300MVA bank
SERC-SE	Meldrim	230	115	Feb-2012	Planned/new 300 MVA, 230/230-kV xfr
SERC-SE	Boulevard	230	115	Jun-2015	Planned/^new 300 MVA, 230/230-kV xfr
SERC-SE	Dorchester	230	115	Jun-2017	Planned/2nd 400 MVA, 230/230-kV xfr
SERC-SE	McIntosh	230	115	Jun-2016	Planned/replace 280 MVA, 230/230-kV xfr W/ 400 MVA xfr
SERC-SE	Waynesboro	230	115	Jun-2019	Planned/replace 280 MVA, 230/230-kV xfr W/ 400 MVA xfr
SERC-SE	Laguna Beach	230	115	Dec-2012	Planned/400 MVA Bank#2
SERC-SE	Santa Rosa BK1	230	115	Jun-2015	Planned/400 MVA Bank#1
SERC-SE	Santa Rosa BK2	230	115	Jun-2015	Planned/400 MVA Bank#2
SERC-SE	Shoal River	230	115	Jun-2022	Planned/400 MVA Bank#2
SERC-SE	Carriere SW	230	115	Jul-2011	Complete/New Substation / Under Construction
SERC-SE	Vimville	230	115	Mar-2013	Planned/New Substation
SERC-SE	Orange Grove	230	115	Jun-2022	Planned/New Substation
SERC-SE	Highland City	230	115	Jun-2013	Planned/400 MVA Bank #1
SERC-SE	Meridian NE Bank 1	230	115	Jun-2013	Planned/Replace Transformer / On Order
SERC-SE	Meridian NE Bank #2	230	115	Jun-2013	Planned/Replace Transformer / On Order
SERC-SE	Ocean Springs Bank #2	230	115	Dec-2014	Planned/Installing a parallel 230/115 kV transformer in an existing station
SERC-SE	Newnan Primary	115	99	Apr-2011	Complete/Replace aged 115/46kV transformer
SERC-SE	silver Creek Interconnection	161	115	Aug-2011	Complete/Silver Creek Interconnection
SERC-SE	Waynesboro Transformer Replacemtn	230	161	Apr-2011	Under Construction/Waynesboro 230/161kV Substation
SERC-SE	Silver Creek Interconnection	161	99	Jun-2011	Planned/Prentiss 161/69kV Substation
SERC-SE	South Hoy 161kV Transmission Project	161	99	Jun-2013	Planned/South Hoy 161/69 kV Substation
SERC-SE	East Waynesboro Substation	161	99	Jun-2013	Planned/East Waynesboro 230/69/ kV Substation
SERC-SE	North Selma Bank #1	230	115	May-2014	Planned/Replace equipment to achieve higher rating
SERC-SE	South Enterprise Bank #1	230	115	May-2015	Planned/New auto at South Enterprise
SERC-SE	Union City	500	230	Jun-2013	Planned/Spare Single Phase Unit
SERC-SE	Highway 54	230	115	Jun-2019	Planned/New transformer
SERC-SE	Moundville AutoBank	230	115	May-2015	Planned/Add 400MVA 230/115kV Autobank at Moundville
SERC-SE	Gadsden 115kV/44kV Replacements	115	99	Dec-2012	Planned/Repalce 2 existing transformers with 2 60MVA Banks

Appendix III: NERC-Wide Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
SERC-SE	North Tifton 500/230kV Auto Replacement	500	230	Jun-2015	Planned/Replace existing 1350-MVA 500/230 kV auto with a new 2016 MVA 500/230 kV auto.
SERC-SE	Northwest 230/115kV Transformer Bank A	230	115	Jun-2014	Planned/Re-rate the existing 280 MVA 230/115 kV auto
SERC-SE	Northwest 230/115 kV Transformer Bank B	230	115	Jun-2014	Planned/Re-rate the existing 280 MVA 230/115 kV auto
SERC-SE	Offerman 230/115kV Autobank Replacements	500	230	Jun-2016	Planned/Replace existing 140 MVA 230/115 kV auto transformers with two 280-300 MVA 230/115 kV auto transformers.
SERC-SE	Scottdale 230/115kV Transformer	230	115	Jun-2020	Planned/Replace 1590 AAC low side jumpers with 2500 AAC jumpers
SERC-SE	South Hall 500/230kV Project	500	230	Jun-2018	Planned/Add a second 2016 MVA, 500/230-kV tfm. at South Hall
SERC-SE	Thomson Primary 230/115kV Project	230	115	Jun-2021	Planned/Install a 2nd 300 MVA, 230/115 kV transformer
SERC-SE	Bassett Creek 230/115kV	230	115	Jun-2015	Planned/Bassett Creek 230/115kV XFMR
SERC-W	Holland Bottoms 500-115	500	115	Dec-2011	Under Construction/Add a new 500-115 kV Substation in Little Rock
SERC-W	Holland Bottoms 500-161	500	161	Jun-2012	Planned/Add a new 500-161 kV Substation in Little Rock
SERC-W	Acadiana Area Improvement Project Phase 1	230	138	May-2011	Complete/Add 500 MVA, 230-138 kV auto at Meaux
SERC-W	Sarepta	345	115	Jun-2011	Under Construction/Construct a new 345-115 kV substation consisting of a 500 MVA auto. Cut station into EL Dorado to Longwood 345 kV line.
SERC-W	Ouachita Transmission Service	500	115	Jun-2012	Planned/Split Sterlington 115 kV bus and replace 500-115 auto #2 with 750 MVA
SERC-W	McAdams	500	230	Jun-2011	Complete/Add 2nd 500/230kV Auto
SERC-W	S.Grenada	230	115	Jun-2012	Planned/Add 230/115kV Auto
SERC-W	Baxter Wilson	500	115	Jun-2012	Under Construction/Add 2nd 500/115kV Auto
SERC-W	Senatobia Industrial	230	115	Jun-2016	Planned/Add 230/115kV Auto
SERC-W	Grimes	345	138	Jun-2018	Conceptual/Add 3rd auto at Grimes; rated 525 MVA
SERC-W	Cypress	500	138	Jun-2018	Conceptual/Add 2nd auto at Cypress; rated 750 MVA
SERC-W	Hartburg	500	230	Jun-2017	Conceptual/Add 2nd auto at Hartburg; rated 800 MVA
SERC-W	PineBluff Voltage Support	500	230	Jun-2015	Planned/Add new 500-230 kV auto at White Bluff
SERC-W	Mabelvale - Replace Autos	500	115	Jun-2016	Planned/Replace existing (2) autos with 800MVA units
SERC-W	SELA Improvement Plan Phase 3	230	115	Jun-2012	Planned/230-115 kV auto at Alliance
SERC-W	Sorrento Upgrade Auto	138	115	Jun-2014	Planned/Sorrento Upgrade 138/115 kV Auto
SPP	Turk	345	138	Sep-2012	
SPP	Canadian River	345	138	Jun-2013	
SPP	Diana	345	138	Jun-2013	
SPP	Shipe Road	345	161	Jun-2014	
SPP	Osage Creek	345	161	Jun-2014	
SPP	Tonnece Substation	345	161	Jul-2012	Transformer installed but not yet energized
SPP	EASTOWN SUB ADDITION	345	161	Dec-2012	
SPP	NASHUA	345	161	Jan-2015	
SPP	ALP	230	138	May-2012	230/138kV 300 MVA transformer at Bonin
SPP	Ogallala T-1 Replacement	230	115	Jun-2014	Replaces existing 187 MVA T-1 with 336 MVA
SPP	Stegall T-2 Addition	345	230	Jun-2015	Addition of second 400 MVA transformer at Stegall
SPP	Ft Smith	500	161	Jun-2017	
SPP	Greenwood	138	69	Jun-2014	
SPP	Woodward EHV	345	138	Jun-2014	
SPP	Northwest	345	138	Jun-2017	
SPP	Pleasant Hill	230	115	Jun-2014	
SPP	Cherry St. Intg.	230	115	Jun-2013	
SPP	Randall County	230	115	Apr-2013	2nd autotransformer
SPP	TUCO	345	230	Jun-2012	2nd autotransformer
SPP	Hitchland-Woodward Project	345	230	Jun-2012	2nd autotransformer

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
SPP	Potter	230	115	Jun-2012	
SPP	Swisher	230	115	Jun-2017	transformer upgrade to 250 MVA
SPP	XIT	230	115	Dec-2015	new 250 MVA; part of 115 to 230kV conversion
SPP	Eddy County	230	115	Apr-2013	2nd autotransformer
SPP	Table Rock 1	161	69	Dec-2012	Replacement
SPP	Paragould 3	161	69	Dec-2013	Replacement
SPP	Poplar Bluff 2	161	69	Dec-2014	Replacement
SPP	Nixa 1	161	69	Dec-2015	Replacement
SPP	Paragould 2	161	69	Dec-2016	Replacement
SPP	Table Rock 2	161	69	Dec-2017	Replacement
SPP	Table Rock 1	161	69	Dec-2012	Replacement
SPP	Rose Hill	345	138	Jun-2013	
SPP	87th Street	345	115	Dec-2012	
SPP	Auburn	230	115	Jun-2014	
SPP	Summit	345	115	Dec-2014	
SPP	Baldwin Creek	230	115	Jun-2015	
SPP	N Manhattan	230	115	Jun-2012	
SPP	Viola	345	138	Dec-2015	Conceptual
SPP	Cocodrie Auto #2	230	138	Jul-2012	Second Autotransformer at Cocodrie Substation
SPP	Wells Auto #2	500	230	Jun-2012	Second Autotransformer at Wells Substation
SPP	Rork Auto #2	230	138	Jul-2012	Second Autotransformer at Rork, From Acadia Power Plant
WECC-US	North Gila	500	230	Jun-2014	Planned
WECC-US	Sun Valley	500	230	Jun-2014	Planned
WECC-US	Meridian T2	500	230	Oct-2013	Coquitlam, near Vancouver
WECC-US	Kelowna Bulk Transformer Capacity Addition	230	138	Dec-2015	Third transformer will be added at the LEE Terminal to provide adequate transformation capacity to supply Kelowna area load during single contingency conditions.
WECC-US	Kitimat Modenization Project	287	25	Feb-2014	Five 287/100/28 kV 219 MVA regulating transformers will be installed (Low-side is 100/25)
WECC-US	Hooper Springs	138	115	Dec-2014	Construct a 200 MVA Hooper Springs Substation adjacent to Three Mile Knoll (PAC) substation. Re-assessing plan of service that has least environmental impacts.
WECC-US	Ponderosa Transformer Addition	500	230	Oct-2013	Central Oregon Reinforcement project, 700 MVA 500/230 transformer at Ponderosa substation. Under construction.
WECC-US	Rocky Reach Auto Transformer #1	230	115	Dec-2016	Transformer Replacement Conceptual
WECC-US	Alberhill System Project	500	115	Jun-2014	This project includes installation of: (a) one 500/115kV substation; (b) two new 500kV line segments; (c) two new 560 MVA 500/115kV transformers; (d) a new 115kV subtransmission line; and (e) modifications to existing 115kV lines
WECC-US	Bayfront Substation Project	230	69	Dec-2012	This project includes installation of: (a) one 230/69kV substation to replace the existing 138/69kV South Bay substation; (b) two 224 MVA 230/69kV transformers; (c) loop in Miguel - Silvergate 230kV line into new substation; (d) transfer all existing 69kV lines from existing South Bay substation to the new substation; (e) re-configure existing 138kV lines to eliminate the need for South Bay 138kV bus
WECC-US	Sunrise Powerlink Project	500	230	Jun-2012	This project includes the following major installation of: (a) one new 500/230kV Suncrest Substation; (b) two new 1120 MVA 500/230kV transformers at Suncrest Substation; (c) one new 500kV line from Imperial Valley to Suncrest substation; (d) two new 230kV overhead/underground lines/cables from Suncrest to Sycamore Canyon substation
WECC-US	Rapids Transformer	230	115	Dec-2013	Transformer at Rapids Switchyard connecting 230-kV bus to 115-kV bus
WECC-US	PICANTE	345	115	Aug-2011	Completed
WECC-US	AFTON	345	115	May-2015	Conceptual
WECC-US	Midpoint S/S	345	230	Jun-2012	Replace existing 500 MVA with new 700 MVA (expected schedule)
WECC-US	Justice S/S	230	138	Dec-2012	New Tie Bank (expected schedule) (Location change - King to Justice)
WECC-US	Borah S/S	500	345	Jun-2019	New Tie Bank (expected schedule)
WECC-US	Bowmont	500	345	Jun-2016	Tie Bank #2
WECC-US	Langley	230	138	Jun-2012	New Tie Bank
WECC-US	Harry Allen 500 /230 kV TX #3	525	230	Dec-2014	Conceptual
WECC-US	Harry Allen 345 /230 kV TX #3	345	230	Jun-2011	In Service
WECC-US	Colstrip 230	230	100	Oct-2011	In Service
WECC-US	Great Falls 230 Switchyard	230	100	Jun-2012	On Site
WECC-US	South Butte	230	161	Dec-2012	In 2012 Budget
WECC-US	Horizon to Sunset	230	115	Jun-2012	Install a 230/115 kV, 320 MVA auto transformer at Horizon Substation
WECC-US	Bethel	500	230	Jan-2017	Installation of a new 500/230 kV transformer bank at PGE's Bethel Substation located in Salem, Oregon
WECC-US	Bethel	230	115	Jan-2017	Replacement of a existing 230/115 kV transformer bank at PGE's Bethel Substation located in Salem, Oregon
WECC-US	Rio Puerco	345	115	May-2011	Fully constructed

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
WECC-US	Yatahey Transformer	345	115	Dec-2015	
WECC-US	Ojo Transformer	345	115	Dec-2014	
WECC-US	Nyberg 115 kV Substation	115	13.8	Unknown	In service during 2011
WECC-US	Overton 115 kV Substation	115	13.8	12-2013	
WECC-US	Reader Tranformer Replacements	115	13.8	12-2013	Replace the two exiting 41 MVAs with two 80 MVAs
WECC-US	Rattlesnake Butte Substation	115	13.8	12-2012	
WECC-US	Boone 230:115 kV Transformer #2	230	115	12-2013	
WECC-US	Fordham T1	230	115	Dec-2011	In service
WECC-US	Fordham T2	230	115	Dec-2011	In service
WECC-US	Horseshoe T1	230	115	May-2012	under construction
WECC-US	Horseshoe T2	230	115	May-2012	under construction
WECC-US	Timberline T2	230	115	May-2013	Planned
WECC-US	Boyd T2	230	115	May-2015	Planned
WECC-US	Missile Site	345	230	Jun-2013	
WECC-US	Alderton Substation Transformer	230	115	Oct-2014	New 230/115-kV transformer at Alderton to feed load growth in Pierce County.
WECC-US	Sedro Woolley Substation Transformer #2	230	115	Oct-2012	New 230/115-kV transformer at Sedro Woolley to feed load growth in Skagit County.
WECC-US	St. Clair Substation Transformer	230	115	Oct-2013	New 230/115-kV transformer at St. Clair to feed load growth in Thurston County.
WECC-US	Lakeside Substation Transformer	230	115	Oct-2017	New 230/115-kV transformer at Lakeside to feed load growth in King County.
WECC-US	Foss Corner Transformer	230	115	Oct-2018	New 230/115-kV transformer at Foss Corner to feed load growth in Kitsap County. This project is conceptual.
WECC-US	Heyborne Substation	60	12.5	Jun-2009	24/32/40 MVA (120kV Initially connected at 60 kV)
WECC-US	Thorne	120	60	Jun-2011	75 MVA (Low-side is 60/12.5)
WECC-US	3rd Kyrene 500/230kV Transformer	500	230	May-2012	Transformer
WECC-US	Pinal Central #1 500/230kV Transformer	500	230	May-2014	Transformer
WECC-US	Pinal Central #2 500/230kV Transformer	500	230	May-2014	Transformer
WECC-US	Vail T3	345	138	May-2012	Substation mdifications are in progress to install transformer upon arrival. Project is on schedule.
WECC-US	Almond GSU #1	115	13.8	May-2012	
WECC-US	Almond GSU #2	115	14	May-2012	
WECC-US	Almond GSU #3	115	14	May-2012	
WECC-US	Grayson	115	69	Mar-2012	
WECC-US	Minnekahta 230/69 kV Substation	230	69	12-2011	70 MVA. Went into service on 12-2011
WECC-US	St. Onge 230/69 kV Substation	230	69	12-2014	150 MVA
WECC-US	East Business Park 115 kV Substation	115	13.8	12-2012	Cheyenne, WY Service Area
WECC-US	North Range 115 kV Substation	115	13.8	12-2012	Cheyenne, WY Service Area
WECC-US	Swan Ranch 115 kV Substation	115	13.8	12-2012	Cheyenne, WY Service Area
WECC-US	Ault 230/115kV XFMR Addition	230	115	12-2012	Phase 2 of the Ault-Cheyenne Project
WECC-US	Laramie River Station 345/230 kV Transformer #2	345	230	Sep-2013	Install a second 345/230 kV - 600 MVA Transformer at the Laramie River Station (LRS).
WECC-US	Liberty Substation Replacement	345	230	Jan-2013	Replace existing 600 MVA unit with like
WECC-US	Mead Substation Replacement	345	230	Jan-2016	Replace existing 600 MVA unit with 1200 MVA
WECC-US	Coolidge Transformer Addition	230	69	Jan-2014	Install new 150 MVA unit

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
WECC-US	Great Falls	230	161	Jun-2012	100 MVA unit. Replaces existing 161/100 kV Rainbow unit. Includes relocation of interconnect with NWE from Rainbow 100 kV to Great Falls 230 kV.
WECC-US	Bowdoin	230	115	Jun-2013	33 MVA unit to serve new substation tap located between existing Richardson Coulee and Malta 161 kV substations for the purpose of new oil load development. (Considered either 161 kV or 230 kv)
WECC-CAN	Livock Phase Shifter	240	240	Jun-2012	
WECC-CAN	Heartland	500	240	Oct-2012	
WECC-CAN	Wolf Creek	240	138	Mar-2013	
WECC-CAN	Hazelwood	240	138	Mar-2013	
WECC-CAN	Johnson	240	138	Mar-2013	
WECC-CAN	Nilrem	240	138	Apr-2012	
WECC-CAN	Pemukan	240	138	May-2013	
WECC-CAN	Lanfine	240	138	Mar-2013	
WECC-CAN	CoyoteLake	240	138	Apr-2013	
WECC-CAN	SS-65	240	138	Jul-2013	
WECC-CAN	Foothills	240	138	Jan-2015	
WECC-CAN	Chapel Rock	500	240	Apr-2016	
WECC-CAN	Fidler	240	138	Aug-2015	
WECC-CAN	Journault	240	138	Jul-2015	
WECC-CAN	Whitla	240	138	Mar-2014	
WECC-CAN	Bowmanton	240	138	Mar-2014	
WECC-MX	Metropoli	230	115	Jan-2016	Planned
WECC-MX	Tijuana	230	115	Jan-2016	Planned
WECC-MX	Cucapah	400	230	Apr-2014	Planned
WECC-MX	Santa Isabel	230	161	Jun-2014	Planned

Appendix IV: About This Assessment

About This Report

The *2012 Long-Term Reliability Assessment* provides an independent view of the 10-year reliability outlook for the North American BPS,[297] while identifying trends, emerging issues, and potential risks. Additional insight will be offered regarding resource adequacy and operating reliability, as well as an overview of projected electricity demand growth for individual assessment areas. The 10-year period observed in this assessment is from 2013-2022, with the 2013 summer as the initial season. Information and data for the 2012 summer and 2012/2013 winter seasons are provided in NERC's seasonal reliability assessments.[298] This new approach eliminates overlap between seasonal and long-term assessments.

2012 Assessment Structure

New for 2012, NERC's seasonal and long-term reliability assessments have been restructured. Prior NERC assessments included Regional or Assessment Area sections with resource adequacy projections combined with additional information describing the methods and assumptions used to arrive at these projections.[299] The resource adequacy outlook for each assessment area is constantly changing, based on the most recent demand forecast, or announcements of new capacity or capacity retirements. However, the methods and assumptions used by each assessment area are more consistent. Therefore, this information (including the most current load forecasting models, resource adequacy studies, and other information used in the development of the seasonal and long-term projections) has been removed from the assessment area sections of the *2012 Long-Term Reliability Assessment* and instead been posted separately on the NERC website.

NERC Assessment Areas

Prior to 2011, NERC seasonal and long-term reliability assessments collected and presented data and information based on Regional Entity boundaries. These boundaries were established through consideration of the respective membership of each Regional Entity, comprising both Planning Coordinators and Load Serving Entities (LSEs). There are approximately 80 NERC Planning Coordinators, 10 of which are Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs), and which encompass a large portion of North America. Four of these Planning Coordinators operate in the Regional Entities listed below:

- American Transmission Co., LLC: MRO, RFC
- Midwest Independent Transmission System Operator, Inc: MRO, RFC, SERC
- PJM Interconnection, LLC: RFC, SERC
- Southwest Power Pool: MRO, SPP

Historically, these four Planning Coordinators have provided capacity and load data to multiple Regional Entities. Consequently, this data was divided based on political boundaries that failed to accurately reflect the planning and operational properties of the BPS. This approach has reduced the accuracy of the resource and demand balance in these four Planning Coordinators that span over multiple Regional Entity boundaries. Taking these considerations into account, NERC instituted the following assessment areas in the 2011:

[297] BPS reliability, as defined in the *How NERC Defines BPS Reliability* section of this report, does not include the reliability of the lower voltage distribution systems, which systems account for 80 percent of all electricity supply interruptions to end-use customers.
[298] NERC *2012 Summer Reliability Assessment* and *2012/2013 Winter Reliability Assessment*: http://www.nerc.com/page.php?cid=4|61.
[299] 2012 LTRA methods and assumptions: http://www.nerc.com/files/2012LTRA_PartII.pdf.

Figure A: 2012 LTRA Assessment Areas[300]



It is important to note that ISO/RTO boundaries are subject to change over time, due to consolidation of LSEs and alterations in resource planning and acquisition arrangements. NERC's Assessment Areas will adjust accordingly, and any potential changes will be identified in future reliability assessments.

The term "Assessment Area" has been applied consistently throughout this reliability assessment. However, the terms "Region" or "subregion" may also be used when the Assessment Area boundaries are synonymous to the Regional Entity or subregional boundaries.[301]

Demand, Resources, and Reserve Margin Concepts

Demand

NERC uses the following terms to categorize on-peak electricity demand:

- **Total Internal Demand**: The sum of the metered (net) output of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all load-modifying non-dispatchable Demand Response programs.

[300] For NERC's seasonal reliability assessments, WECC is divided into four subregions: Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CAMX). These seasonal subregions are structured around WECC's Reserve Sharing Groups that experience similar demand patterns and employ similar operating practices. Additionally, the Western Reliability Coordination Offices collect actual demand data from the Reserve Sharing Groups, and leveraging the same footprints allows for consistent comparisons between demand forecasts and actual demands. NERC further divides the CAMX and NWPP subregions to provide additional data granularity for Canada and Mexico. For additional information, refer to the WECC section.

[301] For example, the ERCOT Assessment Area is synonymous to the ERCOT ISO and TRE Regional Entity; however, there is a PJM Assessment Area, but no PJM region within this assessment.

- **Net Internal Demand**: Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load and not counted as a resource. This value is used in the Planning Reserve Margin calculation.

Capacity Resources

NERC uses the following terms to categorize Capacity Resources and transactions in seasonal assessments:

Existing Capacity Resources

- **Existing-Certain**: Existing generation resources available to operate and deliver power within or into the Assessment Area during the period of assessment.
- **Existing-Other**: Existing generation resources that may be available to operate and deliver power within or into the Assessment Area during the period of assessment, but that may be curtailed or interrupted at any time for various reasons.
- **Existing-Inoperable**: Existing portion of generation resources that are out of service and cannot be brought back into service to serve load during the period assessment.
- Future-Planned: Generation resources anticipated to be available to operate and deliver power within or into the Assessment Area during the period of assessment.
- **Future-Other**: Future generating resources that do not qualify in Future-Planned and are not included in the Conceptual Category.

Capacity Transactions

- **Net Firm and Expected Transactions**: Firm and Expected Imports, minus Firm and expected exports, including all Firm contracts with a reasonable expectation to be implemented.

Reserve Margins

Reserve Margins are capacity-based metrics and do not provide a comprehensive assessment of performance in energy-limited systems (e.g., hydro capacity with limited water resources or systems with significant variable generation). Each Capacity Resource Category is also used to calculate each different Planning Reserve Margin.

Planning Reserve Margins for each Assessment Area are compared to the NERC Reference Margin Level, which is assigned for each NERC Assessment Area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined Reference Margin, NERC has applied 10 or 15 percent Reference Margin Levels for predominately hydro or thermal systems, respectively.

The NERC Reference Margin Level serves as a basis for determining whether more resources (e.g., generation, Demand-Side Management, capacity transfers) may be needed within that Assessment Area.

Demand and Supply forecasts were reported between February and August, 2011 depending on the Assessment Area.

Values for both Total Internal Demand and Net Internal Demand for each Assessment Area represent on-peak projections.

The WECC-United States peak demands or resources do not necessarily equal the sums of the non-coincident WECC-United States subregional peak demands or resources because of subregional monthly peak demand diversity. Similarly, the Western Interconnection peak demands or resources do not necessarily equal the sums of the non-coincident WECC-United States, Canada, and Mexico peak demands or resources. In addition, the subregional resource numbers include use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking portions of the Western Interconnection.

- **2012 Updated Reserve Margin Calculations**

The continued saturation of Demand Response highlights the need for NERC's reliability assessments to accurately reflect how these resources are treated in each Assessment Area. Demand Response programs offer different functionality that ultimately depends on how each program is used by the respective Balancing Authority. While some Demand Response

programs are considered supply-side resources, others are considered as Demand-Side resources, or load modifiers. In 2010, the NERC Resource Issues Subcommittee (RIS) released several recommendations[302] to address the treatment of Controllable Capacity Demand Response (CCDR) in future NERC reliability assessments. Most importantly, all CCDR were to be considered supply-side resources.

Attempts to impellent a uniform approach presented unforeseen complications in NERC's 2011 reliability assessments. While certain Assessment Areas internally modeled CCDR as a load modifier in their Loss of Load Expectation (LOLE) studies, NERC was collecting and presenting CCDR exclusively as a supply-side resource. The most critical impact was reflected in a misrepresentation of the Assessment Area's Reserve Margins.

The Reliability Assessment Subcommittee (RAS) revisited this issue in early 2012 and provided new recommendations for the treatment of Demand Response. Assessment Areas were asked to report Demand Response based on how it is modeled within their respective LOLE studies. Ultimately, Demand Response should be considered as a Demand-Side resource only if the Assessment Area does not carry reserves for this curtailable demand during the peak.

The modifications to the collection and presentation of CCDR have required additional modifications to the Planning Reserve Margin calculations.

Table A: NERC Reserve Margin Updates

Period	Complete		Simplified
Pre-2011	$RM = \frac{[Capacity + CCDR_{TOTAL}] - [Total\ Internal\ Demand - CCDR_{TOTAL}]}{[Total\ Internal\ Demand - CCDR_{TOTAL}]}$	$\Rightarrow$	$\frac{[Capacity + CCDR_{TOTAL}] - Net\ Internal\ Demand}{Net\ Internal\ Demand}$
2011	$RM = \frac{[Capacity + CCDR_{SUPPLY}] - Total\ Internal\ Demand}{Total\ Internal\ Demand}$	$\Rightarrow$	$\frac{[Capacity + CCDR_{SUPPLY}] - Total\ Internal\ Demand}{Total\ Internal\ Demand}$
2012	$RM = \frac{[Capacity + CCDR_{SUPPLY}] - [Total\ Internal\ Demand - CCDR_{DEMAND}]}{[Total\ Internal\ Demand - CCDR_{DEMAND}]}$	$\Rightarrow$	$\frac{[Capacity + CCDR_{SUPPLY}] - Net\ Internal\ Demand}{Net\ Internal\ Demand}$

- **Total Internal Demand** — The sum of the metered (net) output of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all non-dispatchable Demand Response Programs. This value is used in the Planning Reserve Margin calculation.
- **Net Internal Demand** — Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load.

[302] Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculations: http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_Percent2006.01.10.pdf.

Appendix V: Reliability Concepts Used in this Assessment

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:[303]

- **Adequacy** — The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- **Operating Reliability** — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Regarding adequacy, system operators should take "controlled" actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Interruptible demand—demand that the end-use customer makes available to its LSE via contract or agreement for curtailment.[304]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- Rotating blackouts—the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders.

Under the heading of Operating Reliability are all other system disturbances that result in the unplanned or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts"—the uncontrolled successive loss of system elements triggered by an incident at any location.

Planning Reserve Margin

The Planning Reserve Margin is a key metric that measures the flexibility of meeting customer demands and handling the loss of one or more system elements, as well as unforeseen, higher-than-expected demands. Specifically, the Planning Reserve Margin is the difference between the total resource capacity (which includes all generation physically available to provide deliverable power to load, transfers from neighboring area, and Demand Response resources designated as a supply-side resource) and system peak demand. It is the fraction of capacity available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen, higher-than-expected demands.

Planning Reserve Margins are needed because a dependable supply of electricity is essential to the health, safety, and economic well-being of customers. Because electricity cannot be stored in large scale quantities and must be produced at the instant it is used, there must always be some margin to allow for the repair and maintenance of equipment and the unavailability of resources.

Planning Reserve Margins differ from Operating Reserve Margins in that Operating Reserve Margins are based on day-ahead and real-time system needs. Operating Reserve Margins, much like shock absorbers, are needed so that the electric system can respond and rebalance when sudden failures of equipment or sudden increases in customer demand occur. This type of margin must be instantly available so the electric system can remain in dynamic balance. Operating reserves include such products as contingency reserves, spinning and non-spinning reserves, and regulation. Operating Reserve Margins also

[303] Additional information regarding the Adequate Level of Reliability (ALR): http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.
[304] Interruptible Demand (or Interruptible Load) is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

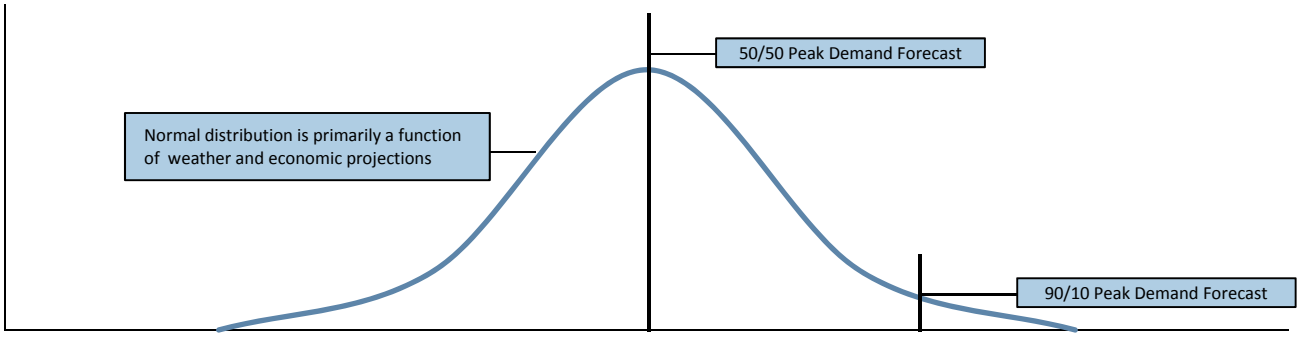
provide flexibility in operations, which allows the system operator to use the most economical plants to serve customer demand, thus reducing fuel and operating costs.

How Margins are Assessed

Proper planning, construction, and operation of the system according to well-established standards and guidelines assure adequate Planning and Operating Reserve Margins. Adequate Planning Reserve Margins depend on future electricity demands, completion of new generation and transmission facilities, retirement of generation, and performance of existing facilities. Assuring sufficient Planning Reserve Margins starts with a forecast of the future electricity requirements of residential, commercial, industrial, and governmental customers for up to 10 years or more in the future. Demand forecasts are continually reviewed and updated as economic conditions and other factors change.

For NERC reliability assessments, aggregated load forecasts are a single number or point; that is, the peak load or energy requirements for a given year are reported as a single specific value. In actuality, any forecast in itself is not a point or single value, but a probability distribution. The specific value represented in the assessment represents the probabilistic midpoint of the distribution such that the likelihood of exceeding it is equal to the likelihood of its not being reached (i.e., a 50/50 forecast). While this has been understood within the industry, increasing interest in and attention to load forecasts by non-industry groups has led to frequent misunderstanding of the forecasts.

Figure B: Example Load Forecast Distribution



Furthermore, point or single value forecasts imply a greater degree of precision and certainty than is appropriate. The load or load growth actually experienced is a function of many factors over which the electric power industry has little or no control—including the performance of local and national economies, the price of electricity, domestic versus foreign production of goods and services, industrial and other policies, changing technologies, federal and state legislation, and weather. These and many other factors greatly influence the actual peak loads and energy requirements and make deviation from forecast values a common occurrence. In addition, comparing actual loads to point forecasts may be misleading since it does not appropriately express the wide variation of causative factors involved.

Both demand and supply forecasts are subject to uncertainties and risks. Changes in future economic growth can affect demand forecasts, and supply forecasts can change if new facilities are delayed, postponed, or cancelled. Generation retirement uncertainties also exist in the supply forecast.

Uncertainty and risks are significant and must be factored into the planning process. Planning Reserve Margins provide the flexibility to mitigate and lower potential risks and uncertainties. The best way to deal with the risks and uncertainties is to increase flexibility by shortening lead times to site, license, and construct facilities, and keeping open all supply and demand options for the future.

Upon calculating Planning Reserve Margins, a comparison to the NERC Reference Margin Level is made. Planning Reserve Margins for each Assessment Area are compared to the NERC Reference Margin Level, which is assigned for each NERC Assessment Area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial

authority, or other delegating body. In the absence of a defined Reference Margin Level, NERC has applied either a 10 or a 15 percent Reference Margin Level for predominately hydro or thermal systems, respectively. There are no NERC Reliability Standards that mandate maintaining a certain level of Planning Reserves. There is also no one appropriate margin for each utility, power pool, ISO/RTO, or Region. Operating conditions tend to be quite different because of changing weather conditions, characteristics of generation and transmission facilities, varying economic conditions, custom demand patterns, etc. Additionally, Planning Reserve Margins are not comparable across the difference Assessment Areas.

Developing Planning Reserve Margin Targets

As BPS planning has become increasingly complex, analytical techniques developed to assess resource adequacy have also become increasingly complex. Common to most methods is a sophisticated application of probability theory. Most techniques require assumptions that also derive from probability theory. For example, an estimate must be made of the probability that generating units modeled will be available when called upon to serve. Historical forced outages rates are used to forecast future rates, but such an assumption is uncertain, and the likelihood of higher or lower rates is inherent in the estimate.

Perhaps the most widely recognized index of reliability is Loss of Load Expectation (LOLE), also known as Loss of Load Probability (LOLP), which is ordinarily measured in days per year. These probabilistic values can then be used to determine what level of Planning Reserve Margin is needed in order to meet a loss of load of 0.1 day per year. Like generation and demand distributions, the LOLE is also a distribution. The ability to serve load without Firm load interruption for every peak hour (except for one) for 10 years is an industry-accepted, non-binding planning guideline. The resulting Planning Reserve Margin target is one that is probabilistically associated with the 0.1 day per year Loss of Load expectation (LOLE = 0.1).

For some Assessment Areas, the methods are not as complex. For example, the FRCC Planning Reserve Margin target (NERC Reference Margin Level) is based on a state-mandated flat percentage. For others, a target is applied based on a generally accepted level using historical performance and engineering judgment.

Demand Response Concepts and Categorization

As the industry's use of Demand-Side Management evolves, NERC's data collection and reliability assessments need to change, highlighting programs and Demand-Side service offerings that have an impact on bulk system reliability.

NERC's seasonal and long-term reliability assessments assume projected Energy Efficiency programs are included in the Total Internal Demand forecasts. This including adjustments for utility indirect Demand Response programs such as Conservation programs, improvements in efficiency of electric energy use and rate incentives, and rebates. DSM involves all activities or programs undertaken to influence the amount and timing of electricity use.

The table below explains Demand Response categories, also defined in Terms Used in this Assessment section.

Table B: NERC Data Collection and Categorization for Demand-Side Management

Demand Response (DR)					
Dispatchable					Non-Dispatchable
Controllable			Economic		
Capacity	Ancillary	Energy-Voluntary	Economic		Time-Sensitive Pricing
Direct Load Control	Spinning Reserves	Emergency	Energy-Price		Time-of-Use
Interruptible Demand	Non-Spinning Reserves		Demand Bidding and Buyback		Critical Peak and Real Time Pricing
Critical Peak Pricing with Control	Regulation				System Peak Response Transmission Tariff
Load as a Capacity Resource					

2012 Emerging Issues and NERC-Supported Studies

The Reliability Assessment Subcommittee keeps the most up-to-date information on emerging reliability issues on the NERC website including published reports and RAS materials. The table below provides a link for additional information on Emerging Reliability Issues discussed in this report (Table C).

Table C: NERC 2012 Emerging Issues

2012 Emerging Reliability Issue	Reference Documents	NERC Actions
Generator Retirements and Environmental Control Retrofits	• Potential Impacts of Future Environmental Regulations[305]	Monitoring of Facility Retirements
Transmission Siting and Planning	• Transmission Siting and Permitting, February 2009, Lawrence Berkeley National Laboratory[306]	Monitoring of Developments
Geomagnetic Disturbance Impacts to System Operations and Communications	• Effects of Geomagnetic Disturbances on the Bulk Power System, Feb. 2012,[307] • Severe Impact Resilience Task Force report[308]	NERC GMDTF Phase 2 Work plan[309]
Global Supply Chains and Fuel Reliability	• National Strategy for Global Supply Chain Security, US Department of Homeland Security, January 2012[310]	Monitoring of Developments
Coordinated Cyber or Physical Attacks on Electricity Infrastructure	• High Impact, Low Frequency Event Risk to the North American BPS, June 2010, NERC and US DOE[311] • Cyber Attack Task Force Report[312], May 2012, SIRTF	Critical Infrastructure Protection Committee Initiatives[313]
Accommodating Variable Resources in System Operations	• Accommodating High Levels of Variable Generation, April 2009[314] • Integration of Variable Generation Task Force reports[315]	Phase 2 Work of the Integrating Variable Generation Task Force
Gas-Electric Interdependency	• A Primer of the Natural Gas and Electric Power Interdependency in the United States, December 2011[316]	Gas-Electric Interdependency Phase II Assessment
Potential Operational Risks Associated with Interaction of SPS / Remedial Action Scheme	• Arizona – Southern California Outages on September 8, 2011: Causes and Recommendations, May 2012 • US Federal Energy Regulatory Commission and NERC[317]	On-going FERC, NERC, and WECC to initiatives to track and mitigate future impacts
Fault-Induced Delayed Voltage Recovery (FIDVR)	• Fault-Induced Delayed Voltage Recovery, December 2008,[318]	PC subcommittees to develop guidelines for addressing protection and control considerations for FIDVR studies
Electric Industry Workforce	• Workforce Trends in the Electric Utility Industry: 2006, US Dept. of Energy[319] • Aging and Retiring Work Force: New Challenges for Public Power[320]	N/A
Aging Infrastructure	• Failure to Act: The Economic Impact of Current Investment Trends in Electricity Infrastructure, 2011, American Society of Civil Engineers[321]	N/A

[305] http://www.nerc.com/files/EPA%20Section.pdf
[306] http://certs.lbl.gov/ntgs/issue-5.pdf
[307] http://www.nerc.com/files/2012GMD.pdf
[308] http://www.nerc.com/filez/sirtf.html
[309] http://www.nerc.com/docs/pc/gmdtf/GMD_Phase_2_Project_Plan_APPROVED.pdf
[310] http://www.whitehouse.gov/sites/default/files/national_strategy_for_global_supply_chain_security.pdf
[311] http://www.nerc.com/files/hilf.pdf
[312] http://www.nerc.com/docs/cip/catf/12-CATF_Final_Report_BOT_clean_Mar_26_2012-Board%20Accepted%200521.pdf
[313] http://www.nerc.com/page.php?cid=1|9|117|139
[314] http://www.nerc.com/files/Special%20Report%20-%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf
[315] http://www.nerc.com/page.php?cid=4|61
[316] http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf
[317] http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf
[318] http://www.nerc.com/docs/pc/tis/FIDV_R_Tech_Ref_V1-1_PC_Approved.pdf
[319] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Workforce_Trends_Report_090706_FINAL.pdf
[320] http://www.publicpower.org/files/pdfs/workforce.pdf
[321] http://www.asce.org/uploadedFiles/Infrastructure/Failure_to_Act/energy_report_FINAL2.pdf

Appendix VI: List of Acronyms

Abbreviation	Term	Abbreviation	Term
A/C	Air Conditioning	ICR	Installed Capacity Requirement
AEP	American Electric Power	IESO	Independent Electric System Operator (in Ontario)
AESO	Alberta Electric System Operator (WECC subregion)	IOU	Investor Owned Utility
AFC	Available Flowgate Capability	IPSI	Integrated Power System Plan
ASM	Ancillary Services Market	IRM	Installed Reserve Margin
ATCLLC	American Transmission Company, LLC	IROL	Interconnection Reliability Operating Limit
ATR	AREA Transmission Review (of NYISO)	IRP	Integrated Resource Plan
AWEA	American Wind Energy Association	ISO	Independent System Operator
BA	Balancing Authorities	ISO-NE	ISO New England, Inc.
BASN	Basin (WECC subregion)	kV	Kilovolts (one thousand volts)
BC	British Columbia (WECC subregion)	LaaRs	Loads acting as a Resource
BCF	Billion cubic feet	LCR	Locational Installed Capacity Requirements
BCFD	Billion cubic feet per day	LDC	Liquidated Damage Contract
CAGR	Compound Annual Growth Rate	LFU	Load Forecast Uncertainty
CALN	California-North (WECC subregion)	LNG	Liquefied Natural Gas
CALS	California-South (WECC subregion)	LOLE	Loss of Load Expectation
CANW	WECC-Canada (WECC subregion, includes AESO and BC)	LOLP	Loss of Load Probability
CFL	Compact Fluorescent Light	LOOP	Loss of off-site power
CMPA	California-Mexico Power Area	LRP	Long Range Plan
COI	California-Oregon Intertie	LSE	Load-serving Entities
COS	Coordinated Outage [transmission] System	LTRA	Long-Term Reliability Assessment
CPUC	California Public Utilities Commission	LTSG	Long-term Study Group
CRO	Contingency Reserve Obligation	MAAC	Mid-Atlantic Area Council
CRPP	Comprehensive Reliability Planning Process (of NYISO)	Maf	Million acre-feet
DADRP	Day-Ahead Demand Response Program	MAIN	Mid-America Interconnected Network, Inc.
DC	Direct Current	MAPP	Mid-Continent Area Power Pool
DCLM	Direct Controlled Load Management	MCRSG	Midwest Contingency Reserve Sharing Group
DFW	Dallas/Fort Worth	MEXW	WECC-Mexico (WECC Subregion)
DLC	Direct Load Control	MISO	Midwest Independent Transmission System Operator
DOE	U.S. Department of Energy	MPRP	Maine Power Reliability Program
DSG	Dynamics Study Group	MRO	Midwest Reliability Organization
DSI	Direct-served Industry	MVA	MegaVolt Ampere
DSM	Demand-Side Management	MVAr	MegaVolt Ampere reactive
DSW	Desert Southwest (WECC subregion)	MW	Megawatts (millions of watts)
DVAR	D-VAR® reactive power compensation system	MWEX	Minnesota Wisconsin Export
EDRP	Emergency Demand Response Program	NB	New Brunswick
EE	Energy Efficiency	NBSO	New Brunswick System Operator
EEA	Energy Emergency Alert	NDEX	North Dakota Export Stability Interface
EECP	Emergency Electric Curtailment Plan	NEEWS	New England East West Solution
EIA	Energy Information Agency (U.S. Department of Energy)	NERC	North American Electric Reliability Corporation
EILS	Emergency Interruptible Load Service (of ERCOT)	NIETC	National Interest Electric Transmission Corridor
EISA	Energy Independence and Security Act of 2007 (USA)	NOPSG	Northwest Operation and Planning Study Group
ELCC	Effective Load-carrying Capability	NORW	Northwest (WECC subregion)
EMTP	Electromagnetic Transient Program	NPCC	Northeast Power Coordinating Council, Inc.
ENS	Energy Not Served	NPDES	National Pollutant Discharge Elimination System
EOP	Emergency Operating Procedure	NPPD	Nebraska Public Power District
ERAG	Eastern Interconnection Reliability Assessment Group	NSPI	Nova Scotia Power Inc.
ERCOT	Electric Reliability Council of Texas	NTSG	Near-term Study Group
ERO	Electric Reliability Organization	NWPP	Northwest Power Pool Area (WECC subregion)
FCITC	First Contingency Incremental Transfer Capability	NYISO	New York Independent System Operator
FCM	Forward Capacity Market	NYPA	New York Planning Authority
FERC	U.S. Federal Energy Regulatory Commission	NYRSC	New York State Reliability Council, LLC
FP	*Future-Planned*	OASIS	Open Access Same Time Information Service
FO	*Future-Other*	OATT	Open Access Transmission Tariff
FRCC	Florida Reliability Coordinating Council	OP	Operating Procedure
GADS	Generating Availability Data System	OPA	Ontario Power Authority
GDP	Gross Domestic Product	OPPD	Omaha Public Power District
GGGS	Gerald Gentleman Station Stability	ORWG	Operating Reliability Working Group
GHG	Greenhouse Gas	OTC	Operating Transfer Capability
GRSP	Generation Reserve Sharing Pool (of MAPP)	OVEC	Ohio Valley Electric Corporation
GTA	Greater Toronto Area	PA	Planning Authority
GWh	Gigawatt hours	PACE	PacifiCorp East
HDD	Heating Degree Days	PAR	Phase Angle Regulators
HVac	Heating, Ventilating, and Air Conditioning	PC	NERC Planning Committee
IA	Interchange Authority	PCAP	Pre-Contingency Action Plans
ICAP	Installed Capacity	PCC	Planning Coordination Committee (of WECC)

Abbreviation	Term	Abbreviation	Term
PJM	PJM Interconnection	SCR	Special Case Resources
PRB	Powder River Basin	SEMA	Southeastern Massachusetts
PRC	Public Regulation Commission	SEPA	State Environmental Protection Administration
PRSG	Planned Reserve Sharing Group	SERC	SERC Reliability Corporation
PSA	Power Supply Assessment	SMUD	Sacramento Municipal Utility District
PUCN	Public Utilities Commission of Nevada	SOL	System Operating Limits
QSE	Qualified Scheduling Entities	SPP	Southwest Power Pool
RA	Resource Adequacy	SPS	Special Protection System
RAP	Remedial Action Plan (of ERCOT)	SPS	Special Protection Schemes
RAR	Resource Adequacy Requirement	SRIS	System Reliability Impact Studies
RAS	Reliability Assessment Subcommittee	SRWG	System Review Working Group
RC	Reliability Coordinator	STATCOM	Static Synchronous Compensator
RCC	Reliability Coordinating Committee	STEP	SPP Transmission Expansion Plan
RFC	ReliabilityFirst Corporation	SVC	Static VAr Compensation
RFP	Request For Proposal	TCF	Trillion Cubic Feet
RGGI	Regional Greenhouse Gas Initiative	TFCP	Task Force on Coordination of Planning
RIS	Resource Issues Subcommittee	THI	Temperature Humidity Index
RMR	Reliability Must Run	TIC	Total Import Capability
RMRG	Rocky Mountain Reserve Group	TID	Total Internal Demand
ROCK	Rockies (WECC subregion)	TLR	Transmission Loading Relief
RP	Reliability Planner	TOP	Transmission Operator
RPM	Reliability Pricing Mode	TPL	Transmission Planning
RRS	Reliability Review Subcommittee	TRE	Texas Regional Entity
RSG	Reserve Sharing Group	TRM	Transmission Reliability Margins
RTEP	Regional Transmission Expansion Plan (for PJM)	TS	Transformer Station
RTO	Regional Transmission Organization	TSP	Transmission Service Provider
RTP	Real-time Pricing	TSS	Technical Studies Subcommittee
RTWG	Renewable Technologies Working Group	TVA	Tennessee Valley Authority
SA	Security Analysis	UFLS	Under Frequency Load Shedding Schemes
SasKPower	Saskatchewan Power Corporation	UVLS	Under Voltage Load-Shedding
SCADA	Supervisory Control and Data Acquisition	VAr	Voltampere reactive
SCC	Seasonal Claimed Capability	VACAR	Virginia and Carolinas (subregion of SERC)
SCD	Security Constrained Dispatch	VSAT	Voltage Stability Assessment Tool
SCDWG	Short Circuit Database Working Group	WALC	Western Area Lower Colorado
SCEC	State Capacity Emergency Coordinator (of FRCC)	WECC	Western Electricity Coordinating Council
		WTHI	Weighted Temperature-Humidity Index
		WUMS	Wisconsin-Upper Michigan Systems

Appendix VII: Terms Used in This Assessment

Ancillary (Controllable Demand Response) — Demand-Side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for non-performance.

Anticipated Capacity Resources — Existing-Certain and Net Firm Transactions plus Future-Planned Capacity Resources plus Resource-Side Demand Response plus Expected Imports, minus Expected Exports.

Anticipated Reserve Margin (Percent) — Anticipated Capacity Resources minus Net Internal Demand, shown as a percent of Net Internal Demand.

Capacity Categories — See **Existing Generation Resources, Future Generation Resources,** and **Conceptual Generation Resources**.

Capacity Margin (Percent) — See **Deliverable Capacity Margin (Percent)** and **Prospective Capacity Margin (Percent)**. Roughly, Capacity minus Demand, divided by Capacity or (Capacity-Demand)/Capacity. Replaced in 2009 with Reserve Margin(s) (Percent) for NERC Assessments.

Conceptual Generation Resources — This category includes generation resources that are not included in Existing Generation Resources or Future Generation Resources but have been identified or announced on a resource planning basis through one or more of the following sources:

- Corporate announcement
- Entered into or is in the early stages of an approval process
- Is in a generator interconnection (or other) queue for study
- "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (percent) to reflect uncertainties associated with siting, project development or queue position.

Conservation — See **Energy Conservation.**

Contractually Interruptible (Curtailable) (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-Side Management achieved by a customer reducing load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be affected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Controllable (Demand Response) — Dispatchable Demand Response, Demand-Side resources used to supplement generation resources resolving system and/or local capacity constraints.

Critical Peak Pricing (CPP) (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours.

Critical Peak Pricing (CPP) with Control (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-Side Management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Curtailable — See **Contractually Interruptible.**

Demand — See **Net Internal Demand**, **Total Internal Demand.**

Demand Response — Changes in electric use by Demand-Side resources from normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or when system reliability is jeopardized. Demand Response can be counted in resource adequacy studies either as a load-modifier, or as a resource.

Derate (Capacity) — The amount of capacity that is expected to be unavailable on seasonal peak.

Direct Control Load Management (DCLM) or Direct Load Control (DLC) (Controllable Capacity Demand Response) — 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.[322]

Dispatchable (Demand Response) — Demand-Side resource curtails according to instruction from a control center.

Disturbance Classification Scale — See **NERC's BPS Disturbance Classification Scale.**

Disturbance Event — See **NERC's BPS Disturbance Classification Scale.**

Economic (Controllable Demand Response) — Demand-Side resource that is dispatched based on an economic decision.

Emergency (Controllable Energy-Voluntary Demand Response) — Demand-Side resource curtails during system and/or local capacity constraints.

Energy Conservation — The practice of decreasing the quantity of energy used.

Energy Efficiency — Permanent changes to electricity use by replacement of end-use devices with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions.

Energy Emergency Alert Levels — The categories for capacity and emergency events based on Reliability Standard EOP-002-0:

- Level 1 — All available resources in use.
- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions in which 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.
- Level 2 — Load management procedures in effect.
- 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, Demand-Side Management, and Utility load Conservation measures.
- Level 3 — Firm load interruption imminent or in-progress.
- 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 Level (Alert) 2, is only accessible with actions taken to increase transmission transfer capabilities.

[322] DCLM is a term defined in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, Updated April 20, 2009 www.nerc.com/files/Glossary_2009April20.pdf

Energy-Only (Capacity) — Energy-only resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

Energy-Price (Controllable Economic Demand Response) — Demand-Side resource that reduces energy for incentives.

Energy-Voluntary (Controllable Demand Response) — Demand-Side resource curtails voluntarily when offered the opportunity to do so for compensation, but non-performance is not penalized.

Existing-Certain (Existing Generation Resources) — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes but is not limited to the following:

1. Contracted (or Firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
2. Where organized markets exist, designated market resource[323] that is eligible to bid into a market or has been designated as a Firm network resource.
3. Network Resource,[324] as this term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy-only resources[325] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[326]
5. Capacity Resources that cannot be sold elsewhere.
6. Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[327] during the period of analysis in the assessment.

Existing-Certain and Net Firm Transactions — Existing-Certain Capacity Resources plus Firm imports, minus Firm exports. (MW)

Existing-Certain and Net Firm Transactions (Percent) (Margin Category) — Existing-Certain and Net Firm Transactions minus Net Internal Demand, shown as a percent of Net Internal Demand.

Existing Generation Resources — See **Existing-Certain**, **Existing-Other**, **Existing-Inoperable**.

Existing-Inoperable (Existing Generation Resources) — This category contains the existing portion of generation resources that are out of service and cannot be brought back into service to serve load during the period of analysis in the assessment. This category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero. This includes all existing generation not included in categories Existing-Certain or Existing-Other, but is not limited to the following:

1. Mothballed generation (that cannot be returned to service for the period of the assessment).
2. Other-Existing but out of service generation (that cannot be returned to service for the period of the assessment).
3. This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.
4. This category does not include partially dismantled units that are not forecast to return to service.

[323] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[324] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[325] Energy-only resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the Area but may be recallable to another Area (Source: 2008 EIA 411 document OMB No. 1905-0129).” Note: Other than wind and solar energy, WECC does not have energy-only resources that are counted towards capacity.
[326] Energy-only resources with transmission service constraints are to be considered in category Existing-Other.
[327] *Ibid*.

Existing-Other (Existing Generation Resources) — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in Existing-Certain. This category includes but is not limited to the following:

- A resource with non-Firm or other similar transmission arrangements.
- Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but that may be curtailed for any reason.
- Mothballed generation (that may be returned to service for the period of the assessment).
- Portions of variable generation not counted in the Existing-Certain Category (e.g., wind, solar, etc.) that may not be available or derated during the assessment period.
- Hydro generation not counted as Existing-Certain or derated.
- Generation resources constrained for other reasons.

Expected (Transaction Category) — A category of Purchases/Imports and Sales/Exports contracts:

1. "Expected" implies that a contract has not been executed, but is in negotiation, projected or other. These Purchases or Sales are expected to be Firm.
2. Expected Purchases or Sales should be considered in the reliability assessments.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contracts:

1. "Firm" implies a contract has been signed and may be recallable.
2. Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriately report the generating capacity that is subject to such Firm contract.

Future Generation Resources (See also **Future-Planned** and **Future-Other**) — This category includes generation resources for which the reporting entity has a reasonable expectation of coming on-line during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.
2. Any of the following regulatory permits being approved:
    a. Site permit
    b. Construction permit
    c. Environmental permit
3. Regulatory approval has been received to be in the rate base.
4. Approved power purchase agreement.
5. Approved and/or designated as a resource by a market operator.

Future-Other (Future Generation Resources) — This category includes future generating resources that do not qualify in Future-Planned and are not included in the Conceptual Category. This category includes but is not limited to generation resources during the period of analysis with the following characteristics:

1. May be curtailed or interrupted at any time for any reason.
2. Energy-only resources that may not be able to serve load during the period of analysis in the assessment.
3. Variable generation not counted in the Future-Planned Category or may not be available or is derated during the assessment period.
4. Hydro generation not counted in Future-Planned Category or derated.
5. Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development, or queue position.

Future-Planned (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes but is not limited to the following:

1. Contracted (or Firm) or other similar resource.
2. Where organized markets exist, designated market resource[328] that is eligible to bid into a market or has been designated as a Firm network resource.
3. Network Resource,[329] as this term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[330]
5. Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

Load as a Capacity Resource (Controllable Capacity Demand Response) — A resource that commits to pre-specified load reductions when system contingencies arise.[331]

NERC's BPS Disturbance Classification Scale[332] — The NERC Event Analysis program breaks events into two general classifications: Operating Security Events and Resource Adequacy Events. Each event is categorized during the triage process to help NERC and Regional Event Analysis staffs determine an appropriate level of analysis or review. Similar to scales used to rank large weather systems and storms, NERC's BPS Event Classification Scale is designed to classify BPS disturbances by severity, size, and impact to the general public.

Operating Security Events — Operating reliability events significantly affect the integrity of interconnected system operations. They are divided into five categories to take into account different ways the system could be impacted.

- **Category 1**: An event results in any one or a combination of the following actions:
    a. The loss of a bulk power transmission component beyond recognized criteria; i.e., single-phase line-to-ground fault with delayed clearing, line tripping due to growing trees, etc.
    b. Frequency below the Low Frequency Trigger Limit (FTL) more than five minutes.
    c. Frequency above the High FTL more than five minutes.
    d. Partial loss of dc converter station (mono-polar operation).
    e. "Clear-Sky" Inter-area oscillations.
    f. Intended and controlled system separation by proper Special Protection Schemes/Remedial Action Schemes (SPS/RAS) action of Alberta from the Western Interconnection, New Brunswick from New England, or Florida from the Eastern Interconnection.
    g. Unintended system separation resulting in an island of a combination of load and generation of 20 MW to 300 MW.
    h. Proper SPS/RAS actuation resulting in load loss of 100 MW to 500 MW.
- **Category 2**: An event results in any one or a combination of the following actions:
    a. Complete loss of dc converter station.
    b. The loss of multiple bulk power transmission components.

[328] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[329] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[330] Energy-only resources with transmission service constraints are to be considered in category Future, Other.
[331] These resources are not limited to being dispatched during system contingencies. They may be subject to economic dispatch from wholesale balancing authorities or through a retail tariff and bilateral arrangements with a third-party curtailments service provider. Additionally, this capacity may be used to meet resource adequacy obligations when determining panning Reserve Margins.
[332] http://www.nerc.com/page.php?cid=5 Percent7C252.

c. The loss of an entire switching station (all lines, 100 kV or above).
d. The loss of an entire generation station of five or more generators (aggregate stations of 75 MW or higher).
e. Loss of off-site power (LOOP) to a nuclear generating station.
f. The loss of load of 300 MW to 500 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
g. Proper SPS/RAS, UFLS, or UVLS actuation that results in loss of load of 500 MW or greater.
h. The loss of generation (between 1,000 and 2,000 MW in the Eastern Interconnection or Western Interconnection and between 500 MW and 1,000 MW in the Texas or Québec Interconnections).
i. The planned automatic rejection of generation through Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) of less than 3,000 MW in the Western Interconnection, or less than 1,500 MW in the Eastern, Texas, and Québec Interconnections.
j. Unintended system separation resulting in an island of a combination of load and generation of 301 MW to 5,000 MW.
k. SPS/RAS misoperation.

- **Category 3**: An event results in any one or a combination of the following actions:
  a. The loss of load from 500 MW to 1,000 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  b. The unplanned loss of generation (excluding automatic rejection of generation through SPS/RAS) of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, and 1,000 MW or more in the Texas or Québec Interconnections.
  c. Unintended system separation resulting in an island of a combination of load and generation of 5,001 MW to 10,000 MW.

- **Category 4**: An event results in any one or a combination of the following actions:
  a. The loss of load from 1,000 MW to 9,999 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  b. Unintended system separation resulting in an island of a combination of load and generation of more than 10,000 MW.

- **Category 5**: An event results in any one or a combination of the following actions:
  a. The loss of load of 10,000 MW or more.
  b. The loss of generation of 10,000 MW or more.

Resource Adequacy Events — Adequacy events are divided into three categories based on Standard EOP-002-0 (Capacity and Energy Emergencies).

- **Category A1**: No disturbance events and all available resources in use.
  a. Required operating reserves cannot be sustained.
  b. Non-Firm wholesale energy sales have been curtailed.

- **Category A2**: Load management procedures in effect.
  a. Public appeals to reduce demand
  b. Voltage reduction
  c. Interruption of non-Firm end per contracts
  d. Demand-Side Management
  e. Utility load Conservation measures

- **Category A3**: Firm load interruption imminent or in progress.

(NERC) Reference Margin Level (Percent) — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (i.e., thermal/hydro). Each Region/subregion may have its own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals,

the regional/subregional Target Reserve Margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and for predominately hydro systems, 10 percent.

Net Internal Demand — Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

Non-Dispatchable (Demand Response) — Demand-Side resource curtails according to tariff structure, not instruction from a control center.

Non-Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contracts:

1. "Non-Firm" implies a non-Firm contract has been signed.
2. Non-Firm Purchases and Sales should not be considered in the reliability assessments.

Non-Spin Reserves (Controllable Ancillary Demand Response) — Demand-Side resource not connected to the system but capable of serving demand within a specified time.

On-Peak (Capacity) — The amount of capacity that is expected to be available on seasonal peak.

Operating Reliability Events Categories — See **NERC's BPS Disturbance Classification Scale.**

Prospective Capacity Reserve Margin (Percent) — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Prospective Capacity Resources (MW) — Anticipated Capacity Resources plus Existing-Other Capacity Resources, plus Future-Other Capacity Resources.

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports with contracts. Provisional implies that the transactions are under study but negotiations have not begun. These Purchases and Sales are expected to be provisionally Firm.

Purchases/Imports — See **Transaction Categories.**

Real-Time Pricing (RTP) (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Reference Margin Level — See **NERC Reference Margin Level.**

Regulation (Controllable Ancillary Demand Response) — Demand-Side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Renewable Energy — The United States Department of Energy, Energy Efficiency and Renewable Energy glossary defines "Renewable Energy" as "energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource."[333] The government of Canada has a similar definition.[334] Variable generation is a subset of Renewable Energy — See **Variable Generation**.

Renewables — See **Renewable Energy.**

[333] http://www1.eere.energy.gov/site_administration/glossary.html#R.
[334] http://www.cleanenergy.gc.ca/index.cfm?action=faq.summary.

Reserve Margin (Percent) — See **Deliverable Capacity Reserve Margin (Percent)** and **Prospective Capacity Reserve Margin (Percent)**. Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced Capacity Margin(s) (Percent) for NERC Assessments in 2009.

Resource Adequacy Events — See **NERC's BPS Disturbance Classification Scale.**

Sales/Exports Contracts — See Transaction Categories.

Spinning/Responsive Reserves (Controllable Ancillary Demand Response) — Demand-Side resources that are synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

System Peak Response Transmission Tariff (Non-dispatchable Time-Sensitive Pricing Demand Response) — The rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

Target Reserve Margin (Percent) — Established target for reserve margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Margin Level is used if a Target Reserve Margin is not provided.

Total Internal Demand — The sum of the metered (net) output of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electric energy use, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real-time Pricing and System Peak Response Transmission Tariffs) and some dispatchable Demand Response (such as Demand Bidding and Buy-Back). Adjustments for controllable Demand Response should not be incorporated in this value.

Time-of-Use (TOU) (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and/or price structures with different unit prices for use during different blocks of time.

Time-Sensitive Pricing (Non-dispatchable Demand Response) — Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost or peak periods.

Transaction Categories (See also **Firm, Expected and Provisional**) — Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one Region and sold to another Region, the Region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside Region. The purchasing Region reports such capacity as a purchase but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

Transmission-Limited Resources — The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the Region. If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example, a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

Transmission Loading Relief (TLR) Levels — Various levels of the TLR Procedure from Reliability Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief:

- TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations
- TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations
- TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-Firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service
- TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate an SOL or IROL Violation
- TLR Level 4 — Reconfigure Transmission
- TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro-rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service
- TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation
- TLR Level 6 — Emergency Procedures
- TLR Level 0 — TLR concluded

Transmission Status Categories — Transmission additions were categorized using the following criteria:

- Under Construction: Construction of the line has begun
- Planned (any of the following):
- Permits have been approved to proceed
- Design is complete
- Needed in order to meet a regulatory requirement
- Conceptual (any of the following)
- A line projected in the transmission plan
- A line that is required to meet a NERC TPL Standard or included in a powerflow model and cannot be categorized as "Under Construction" or "Planned"
- Projected transmission lines that are not "Under Construction" or "Planned"

Variable Generation — Variable generation technologies generally refer to generating technologies whose primary energy source varies over time and cannot reasonably be stored to address such variation.[335] Variable generation sources that include wind, solar, ocean and some hydro generation resources are all renewable-based. Variable generation in this report refers only to wind and solar resources. There are two major attributes of a variable generator that distinguish it from conventional forms of generation and may impact the BPS planning and operations: variability and uncertainty.

- **Variability** — The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.
- **Uncertainty** — The magnitude and timing of variable generation output is less predictable than for conventional generation.

[335] http://www.nerc.com/files/IVGTF_Report_041609.pdf.

Appendix VIII: Probabilistic Assessments

Beginning in 2012, the NERC Reliability Assessment Subcommittee has enhanced its reliability assessment process by supplementing its resource adequacy metric (mainly Planning Reserve Margin) with probabilistic metrics.

NERC's Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) recommended the creation of an annual report summarizing a probabilistic assessment of the resource adequacy by area across NERC.[336] The GTRPMTF was subsequently disbanded and the Planning Committee has assigned RAS to coordinate the assembly of this report.

In 2011, the RAS piloted this effort to produce enhanced resource adequacy metrics for the *2010 Long-Term Reliability Assessment*.[337] The NERC Planning Committee (PC) approved the recommendations from this report which initiates a mandatory probabilistic assessment study to be performed biennially.

The *Probabilistic Assessment* report is designed to complement the *Long-Term Reliability Assessment* by providing additional probabilistic statistics of Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE). Included in this request, RAS plans to report on the third and fifth year of the *2012 Long-Term Reliability Assessment*—2014 and 2016 results.

Because of the complexity and time requirements of configuring and running models to produce probabilistic results, the analysis schedule does not align with the timeline of the *Long-Term Reliability Assessment.* Therefore, the probabilistic assessment will be published biennially in the following spring after the *Long-Term Reliability Assessment* is published. The schedule for completion is as follows:

August 21, 2012	Introduction webinar - field participant questions
September 6, 2012	Issue letter requesting participation in 2012 assessment
September-October 2012	Confirm final *2012LTRA R*eference case data
December 10, 2012	RAS-ProbA Team conference call: pre-submission inquires
October 21, 2012	First draft due to NERC
January 17, 2013	RAS-ProbA Team conference call: peer review
February 1, 2013	Final drafts due to NERC
February 4-8, 2013	NERC staff consolidation of reports
February 8, 2013	Draft report submitted to RAS-ProbA Team
February 15, 2013	RAS-ProbA Team conference call: review of initial draft
February 25, 2013	Draft report submitted to RAS
March 2013	Draft report submitted to PC (possible approval in March)
June 2013	PC approval of final report

More information can be found on the NERC Reliability Assessment Subcommittee website.[338]

[336] http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF_Meth_&_Metrics_Report_final_w._PC_approvals,_revisions_12.08.10.pdf
[337] *2010 Long-Term Reliability Assessment: Pilot Probabilistic Assessment,* June 2012: http://www.nerc.com/files/2012_ProbA.pdf
[338] http://www.nerc.com/filez/ras.html

Appendix IX: Assessment Preparation

This assessment was prepared by NERC in its capacity as the Electric Reliability Organization.[339] NERC cannot order construction of generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Federal Power Act and similar restrictions in Canada.[340] In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

The Assessment Area sections were developed by the Reliability Assessment Subcommittee (RAS), which is under the direction of the NERC Planning Committee (PC). The data and information presented in this assessment was submitted by each of the eight Regional Entities on an Assessment Area basis. Additional data was incorporated by NERC staff with sources provided when applicable.

Reliability Assessment Subcommittee Members

Name	Position	Represents	Job Title	Organization
Vince Ordax	Chair	FRCC*	Manager of Planning	FRCC
Curtis Crews	Vice Chair	TRE*	Lead Reliability Assessment Engineer	TRE
Justin Michlig	Member	MRO	Transmission Planning Specialty Engineer	Xcel
William B. Kunkel	Member	MRO*	Senior Engineer	MRO
John Lawhorn	Member	MRO	Senior Director, Regulatory and Economic Studies	Midwest ISO, Inc.
Madhuri Kandukuri	Member	MRO	Senior Engineer , Regulatory and Economic Studies	Midwest ISO, Inc.
Josh Collins	Member	MRO	Engineer I	Midwest ISO, Inc.
Bagen Bagen	Member	MRO	Principal Planning Engineer	Manitoba Hydro
Salva R. Andiappan	Member	MRO	Manager- Modeling and Reliability Assessments	MRO
Rao Konidena	Member	MRO	Manager, Resource Forecasting	Midwest ISO, Inc.
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Philip A. Fedora	Member	NPCC*	Assistant Vice President, Reliability Services	NPCC
John G Mosier Jr.	Member	NPCC*	Assistant Vice President of System Operations	NPCC
Paul A. Roman	Member	NPCC	Manager, Operations Planning	NPCC
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[339] Section 39.11(b) of the U.S. FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[340] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf.

Assessment areas are subject to thorough review by the RAS. This review allows all members multiple opportunities to examine information and data provided by each assessment area. Data sharing also allows members to validate capacity transfers between neighboring assessment areas.

The NERC PC endorses this report prior to its being sent to the NERC Board of Trustees (BOT) for approval. The draft includes comments received from representatives on the NERC Operating Committee (OC) and the Member Representatives Committee (MRC). Drafts of the document are considered confidential and embargoed until approval is received from the NERC BOT.

2012 Long-Term Reliability Assessment Data and Information Request (Distributed by NERC in January, 2012)

- Letter to Regional Entities: http://www.nerc.com/docs/pc/ras/2012%20LTRA%20Request%20Letter.doc.
- Data Form: http://www.nerc.com/docs/pc/ras/ERO2012_LTRA_v4.xls.
- Data Form Instructions: http://www.nerc.com/docs/pc/ras/ERO2012_LTRA_v3_Instructions.pdf .
- Schedule: http://www.nerc.com/docs/pc/ras/2012LTRA_Schedule_Updated.pdf .

2012 Long-Term Reliability Assessment Supplemental Data and Information Request

In July 2012, NERC requested additional information and data to support changes in reference cases and more granular data on projected generator retirements. The supplemental data request also required the assessment areas to submit estimates of on-peak gas-fired generation capacity (MW) with firm supply and transportation of natural gas.

- Letter to Regional Entities: http://www.nerc.com/docs/pc/ras/2012LTRA_Supplemental_Letter.pdf.
- Supplemental Data Form http://www.nerc.com/docs/pc/ras/ERO2012_LTRA_Supplemental_v3.xls.
- Supplemental Data Form Instructions: http://www.nerc.com/docs/pc/ras/2012LTRA_Supplemental_Request-Instructions_v2.pdf.

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2012/2013 Winter Reliability Assessment

November 2012

RELIABILITY | ACCOUNTABILITY






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This assessment was prepared by NERC in its capacity as the Electric Reliability Organization[1] and provides an independent view of the 2012/2013 winter reliability outlook for the North American BPS,[2] while identifying trends, emerging issues, and potential risks. Additional insight will be offered regarding resource adequacy and operating reliability, as well as an overview of projected seasonal electricity demand for individual assessment areas.

Additional inquiries regarding the information, data, and analysis in this seasonal assessment may be directed to the NERC Reliability Assessment Staff:

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Errata

Section	Subsection	Page Number	Change
MRO-SaskPower	2012/2013 Winter Season: Assessment Area Summary Table	33	Correction of erroneous demand response value.
SPP	2012/2013 Winter Season: Assessment Area Summary Table	68	Correction of winter resource mix values.

[1] Section 39.11(b) of the U.S. FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[2] BPS reliability, as defined in the *How NERC Defines BPS Reliability* section of this report, does not include the reliability of the lower voltage distribution systems, which systems account for 80 percent of all electricity supply interruptions to end-use customers.

Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) of North America.[3,4] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces reliability standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[5]

Reliability Standards are the planning and operating rules that electric utilities follow to support and maintain a reliable electric system. These standards are developed by the industry using a balanced, open, fair and inclusive process accredited by the American National Standards Institute (ANSI). While NERC does not have authority to set Reliability Standards for resource adequacy (e.g., reserve margin criteria) or to order the construction of resources or transmission, through reliability assessment, NERC can independently assess where reliability issues may arise as well as identify emerging risks. This information, along with NERC recommendations, is then available to policy makers and federal, state, and provincial regulators to support decision making within the electric sector.

NERC Regional Entities	
FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

NERC Regional Entities Map



NERC Assessment Areas Map



NERC prepares seasonal and long-term assessments of the overall reliability and adequacy of the North American BPS, which is divided into 26 assessment areas, both within and across the eight Regional Entity boundaries, as shown by the corresponding table and maps above.[6] To prepare these assessments, NERC collects and consolidates data from the eight Regional Entities, including forecasts for on-peak demand and energy, demand response, resource capacity, and transmission projects. The use of this bottom-up approach accounts for virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The information is analyzed to identify notable trends, emerging issues, and potential concerns regarding future electricity supply, as well as the overall adequacy of the BPS to meet future demand. Reliability assessments are developed with the intention of informing industry, policy makers, and regulators and to aid NERC in achieving its mission—to ensure the reliability of the North American BPS.

[3] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf.

[4] The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[5] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory and enforceable in that jurisdiction.

[6] Assessment area boundaries are included in Appendix IV of this assessment.

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Executive Summary

For the 2012/2013 winter operating period (December 1, 2012 through February 28, 2013), all of the assessment areas are projecting sufficient resources to meet winter peak demands.

The three key findings highlight either a common theme across North America or region-specific challenges:

- Planning Reserve Margins Sufficient to Accommodate Normal Winter Weather
- Extreme Winter Weather in Northeast Could Lead to Increased Gas-Fired Generator Outages
- Improved Winterization in the Southwest

Additional highlights of the report include:

- The NOAA 3-month winter outlook (December-February) lacks a strong signal for extreme cold. With the exception of Florida, NOAA predicts average or above average temperatures. Seasonal weather forecasts from Environment Canada show similar (average) predictions.
- NERC-wide, projected anticipated resources have increased by 14.9 GW since the 2011/2012 winter season. Peak demand is forecast to decline by 5.9 GW NERC-wide, as economic conditions impact electricity demand.
- Total demand response available to system operators (load Modifying and resource-side) will be approximately 26,400 MW for the 2012/2013 winter operating season.
- The western U.S. experienced a relatively warm and dry 2012 summer, resulting in further deterioration of the winter snow pack and corresponding reservoir drawdown's. Drought conditions are also persistent in some areas of WECC. It is expected that the reduced river flows will result in increased thermal-based energy generation, but this will not significantly affect the ability to meet peak demand and no other issues of resource adequacy have been identified by WECC for this winter.
- Natural gas working inventories are approximately 136 billion cubic feet (Bcf) above levels recorded in October 2011. No other fuel delivery issues are noted by assessment areas due to large on-site stocks of coal supplies.

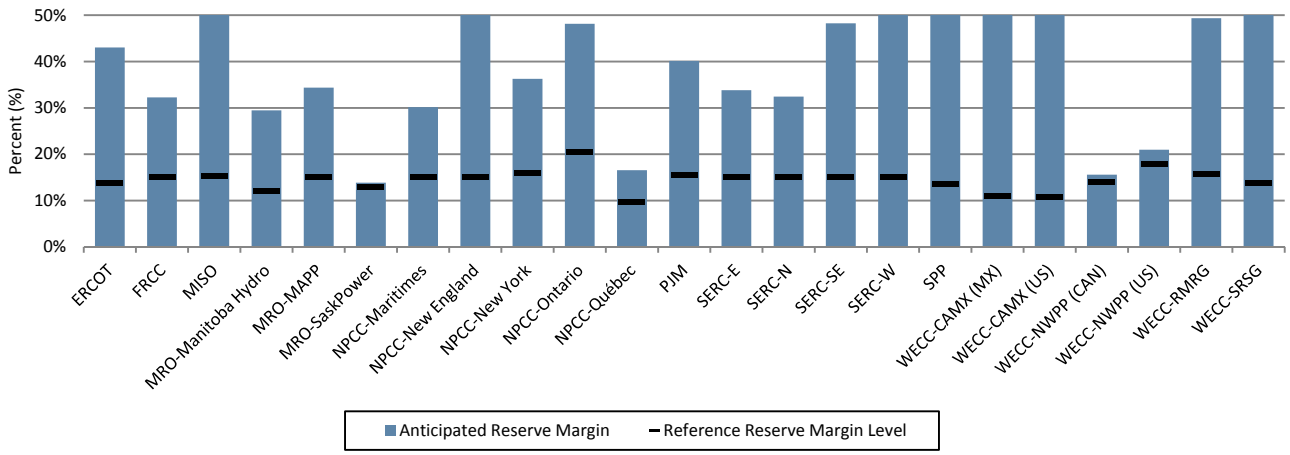
The NERC Winter Reliability Assessment has traditionally focused on the evaluation of resource adequacy and the preparations to meet peak demands for winter-peaking areas. However, the growth in natural gas demand within the electric sector has important implications on electric reliability. Increased dependence on natural gas for generating capacity has increased the need for all gas customers, as well as policy makers, to focus more sharply on the interaction between the electric and gas industries. Most importantly, in the coming years the Winter Reliability Assessment will become a valuable tool to track and assess how areas across North America will incorporate fuel dependency risks into their seasonal plans and capacity assessments. This is a vital step for NERC to understand how potential fuel interruptions and/or curtailments will be mitigated as well as understanding the assumptions for generation availability.

2012/2013 Winter Season Key Findings

Planning Reserve Margins Sufficient to Accommodate Normal Winter Weather

The North American electric industry is projecting sufficient availability of resources to serve projected peak demand during the 2012/2013 winter operating season (December 1, 2012 through February 28, 2013). Figure 1 shows the reserve margins for the peak demand month (which varies for each assessment area) for the 2012/2013 winter operating season. Because a majority of the NERC Assessment Areas experience peak demand during the summer, Anticipated Reserve Margins exceed NERC Reference Margin Levels for all assessment areas. For the winter assessment, focus is generally drawn to the winter-peaking areas in Canada (with the exception of Ontario) and the northwest. For these areas, sufficient generation is expected. From a NERC-wide perspective, projected anticipated resources have increased by 14.9 GW since the 2011/2012 winter season.[7] Peak demand is forecast to decline by 5.9 GW NERC-wide compared to last year, as economic conditions impact electricity demand.[8]

Figure 1: NERC-Wide 2012/2013 Winter Peak Reserve Margins



Eight of 23 assessment areas throughout North America are forecast to experience substantial reductions (-3.7 percent) in peak demand compared to a year earlier. Compared to the 2011/2012 winter forecast (issued in November 2011), SERC-N, MISO,[9] and SPP experience the most significant drop in peak demand of 2,042 MW, 4,909 MW, and 5,279 MW, respectively.[10] Several winter-peaking assessment areas, including MRO-Manitoba Hydro, NPCC-Maritimes and NPCC-Ontario, also see modest reductions in demand projections compared to the 2011/2012 winter.

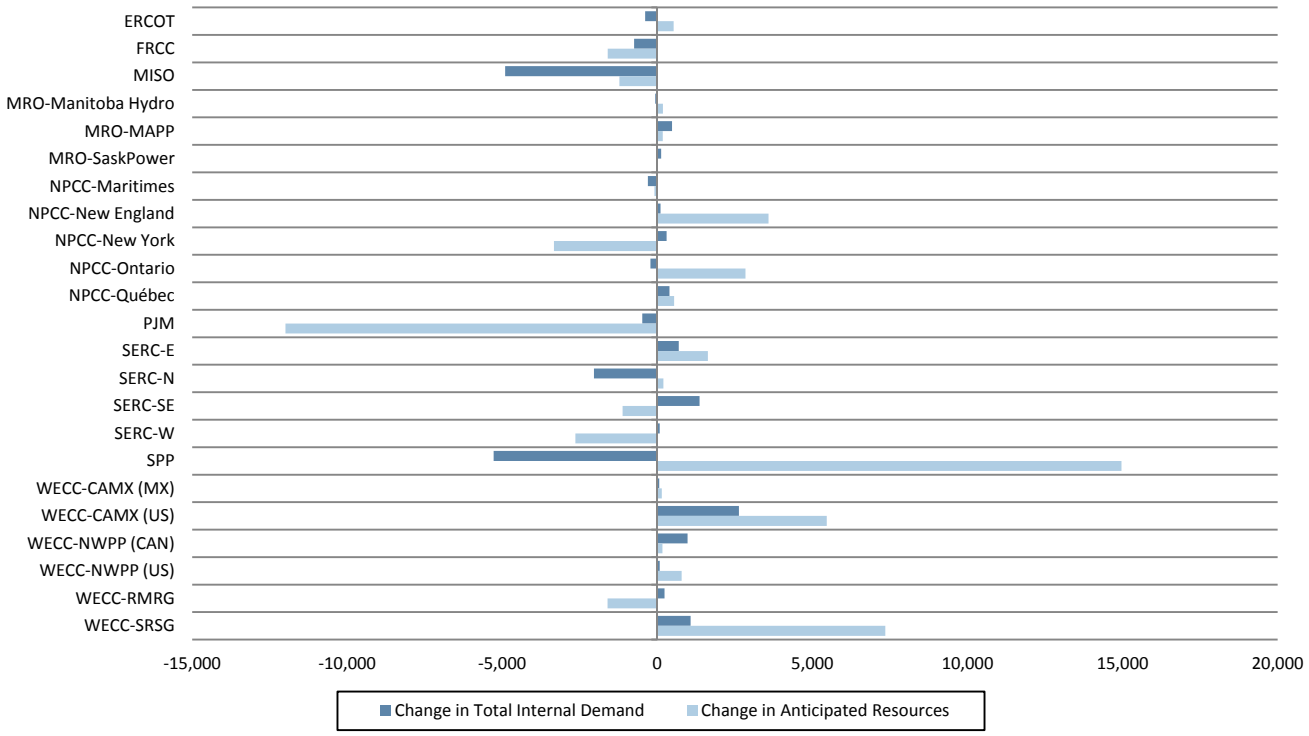
The 2011/2012 winter was the fourth warmest on record for the contiguous 48 states, resulting in only one assessment area (WECC-SRSG) experiencing an actual peak demand above forecast. According to the National Oceanic and Atmospheric Administration's (NOAA), the 2012/2013 winter outlook calls for similar above-normal temperatures across the western portion of the United States.[11] Environment Canada is predicting normal forecast temperatures for a majority of Canada for the upcoming winter as well.[12]

[7] This does not imply that 14.9 GW of capacity has been added in the past year. The increase can be attributed to capacity growth, additional resource-side demand response, generation put back into service that was unavailable during the 2011/2012 winter peak or a change in generation reporting methodology.
[8] SPP's demand forecast change is primarily due to a change in methodology. See the Demand section of SPP's assessment.
[9] MISO's membership has changed since the 2011 winter. Duke Energy Ohio and Duke Energy Kentucky consolidated into the PJM RTO on January 1st 2012, removing approximately 5,700MW of load and generation from MISO's footprint. The Entergy operating companies Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc. intend to join MISO in December 2013; this is not included in the assessment.
[10] SPP's demand forecast change is primarily due to a change in methodology. See the Demand section of SPP's assessment.
[11] 2012 NOAA NWS Climate Prediction Center. College Park, MD. Updated October 18, 2012: http://www.cpc.ncep.noaa.gov/products/predictions/90day/fxus05.html.
[12] Environment Canada: http://www.weatheroffice.gc.ca/saisons/index_e.html.

Based on heating degree days, NOAA also expects the Northeast, Midwest, and South to be about 2 percent warmer than the 30-year average (1971-2000), but approximately 20 percent to 27 percent colder than last winter. Florida is projected to experience below-normal temperatures, which could impact electricity demand (the peak demand forecast for FRCC this winter is 46,864 MW, which is based on normal-weather conditions).

Most of western Canada, including WECC-NWPP (CAN) and MRO-SaskPower, are also expected to endure colder winter temperatures than compared to the 2011/2012 winter season.[13] Changes in 2012/2013 Total Internal Demand and changes in anticipated resources are shown in Figure 2.[14,15] For the winter-peaking areas, only slight changes from the prior year are expected. However, WECC-NWPP (US) is expected a significant reduction in demand when compared to last year.

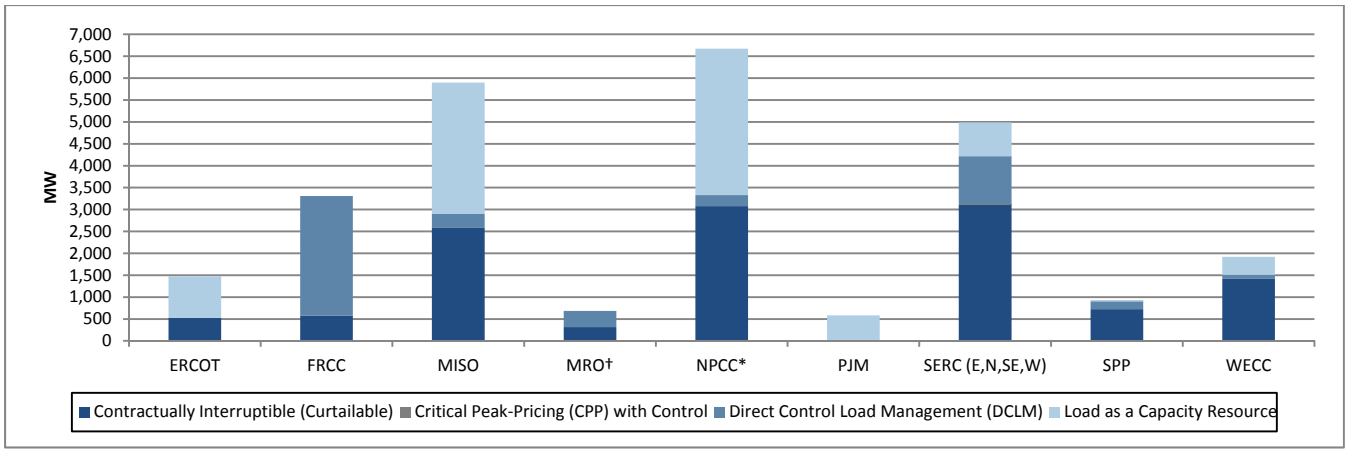
Figure 2: NERC-Wide Change in Total Internal Demand and Change in Anticipated Resources from Prior Year



Demand-side management programs, which include conservation, energy efficiency, and a variety of demand response programs, provide the electric power industry the ability to reduce peak demand and to potentially defer the need for additional future generation or transmission. Demand-side management is the term for activities or programs undertaken by a utility or an ISO/RTO with electricity end-users to influence the amount or timing of electricity they use. NERC collects controllable capacity demand response (CCDR) programs in four categories. These four types of demand response programs support reliability and are counted on to meet resource adequacy requirements (Figure 3).

Figure 3: NERC-Wide Demand Response Programs for 2012/2013

[13] Environment Canada. Monthly and Seasonal Forecasts: http://www.weatheroffice.gc.ca/saisons/index_e.html
[14] The change in SPP's Anticipated Resources is due to the way SPP is now reporting capacity resources. See SPP's Generation section of the assessment.
[15] The 12,000 MW reduction in PJM is due to boundary restructuring and maintenance outages.



Demand response (DR) programs for this winter total approximately 26,461 MW for all of NERC (Load Modifying DR: 17,138 MW and Resource-side DR: 9,323 MW). Additional flexibility is provided to operators who facilitate the use of demand response resources to support local reliability issues and other system constraints as needed. For example, demand response is being used more and more to provide ancillary services, though these programs are still in their infancy and only a small amount of capacity provides these services. Technological improvements in activation methods, as well as measurement and verification reinforce operator's confidence in demand resources in providing fast-acting response when grid conditions are stressed.

Extreme Winter Weather in Northeastern United States Could Lead to Increased Gas-Fired Generator Outages

The growth in natural gas demand within the electric sector has important implications on other gas using sectors, such as commercial and residential heating or industrial manufacturing. Increased dependence on natural gas for generating capacity has increased the need for all gas customers, from electric system planners and operators to gas pipeline operators, as well as policy makers to focus more sharply on the interaction between the electric and gas industries.

This is especially true in NPCC-New England, where gas fired capacity accounts for approximately 45 percent of the total capacity outlook.[16] For a variety of reasons, including the adoption of highly efficient combined cycle technology by the electric power industry and the emergence of shale gas, both of which have altered the relative economics of gas-fired generation, the dependence on natural gas by the electric power sector has increased significantly.

Figure 4: New England Capacity Mix for the 2012/2013 Winter Season

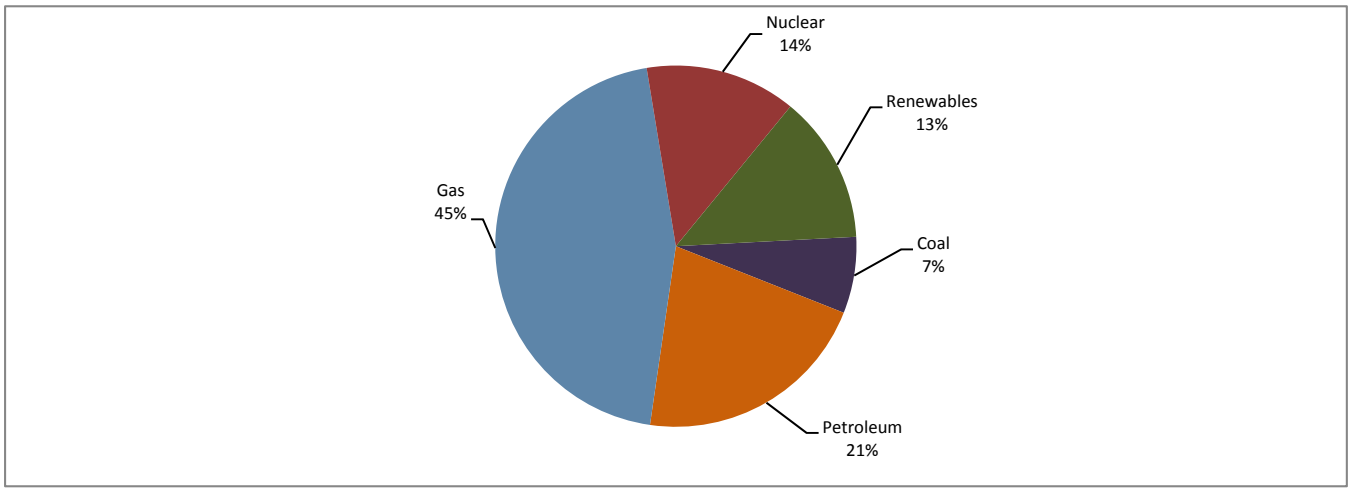
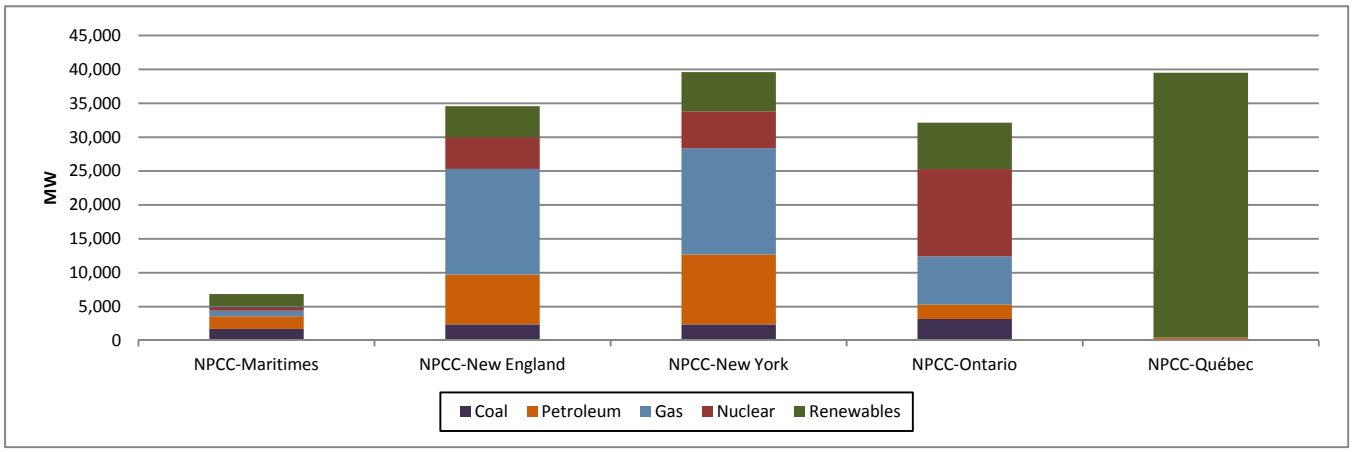


Figure 5: NPCC Subregions – Capacity Mix for the 2012/2013 Winter Season



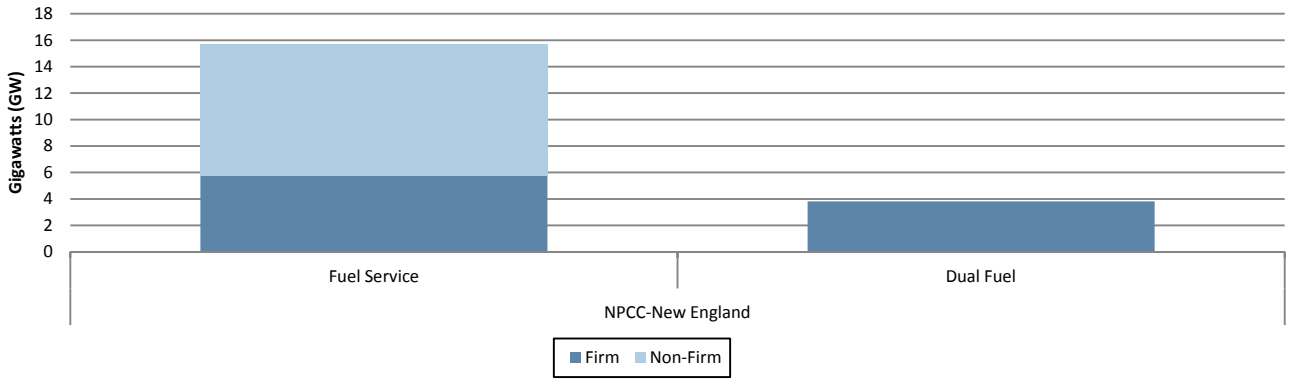
Cold weather also drives demand for natural gas. A milder than expected winter (similar to the 2011/2012 winter operating season) could even further moderate demand for natural gas, with natural gas storage reaching all-time peak levels.

[16] 2012 Long Term Reliability Assessment, NERC, http://www.nerc.com/page.php?cid=4|61.

A colder than projected winter season would increase demand by residential consumers and power generators.[17,18] Given the high amount of domestic production and large amount of working natural gas storage, gas supplies are not expected to affect bulk power system reliability.[19]

However, with pipeline capacity constrained in the northeast this winter, the electric industry will need to carefully evaluate how a disruption in fuel transportation services could affect the gas-fired generation fleet. While many infrastructure enhancements are underway to improve constrained areas, appropriate planning, including the evaluation of different scenarios, should be completed by the Planning Coordinators prior to the start of the winter season. Proper emergency procedures are needed to ensure backup fuel is available and that generators that have dual-fuel capabilities are prepared to mitigate pipeline services losses. Information on these preparations, as well as the up-to-date status of generator capabilities, is critical to ensure system operators can posture the system to withstand or manage credible and potentially known contingencies.

Figure 6: Natural Gas Fuel Service for NPCC-New England



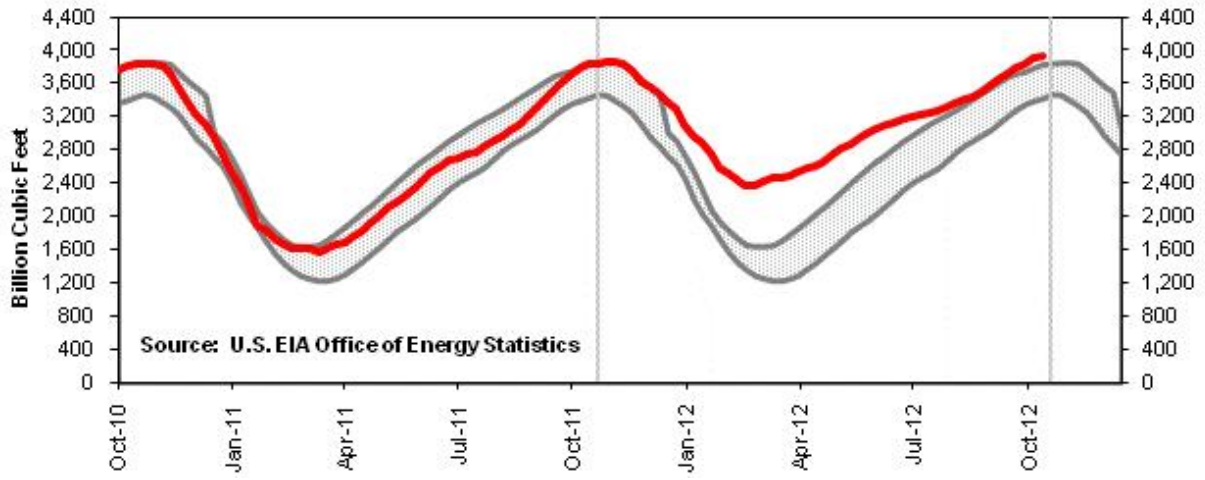
Natural Gas Production and Storage

Natural gas working inventories, ending on October 26, 2012, showed a storage value of 3.9 trillion cubic feet (Tcf). This storage value is approximately 136 billion cubic feet (Bcf), above the same point in 2011, and also above the five-year average.

EIA projects that working natural gas inventory storage levels will approach last year's high levels by the end the injection season, which typically ends at the end of October each year.

[17] With the exception of Florida, NOAA predicts average or above average temperatures http://www.noaanews.noaa.gov/stories2012/images/Outlook_map_temp_2b.jpg
[18] Seasonal weather forecasts from Environmental Canada show similar (average) predictions. http://www.weatheroffice.gc.ca/saisons/index_e.html#proba
[19] Natural Gas Storage is covered in more detail in the Key Highlight: Natural-Gas Fuel Deliverability Concerns for the 2012/2013 Winter Season.

Figure 7: Working Gas in Underground Storage Compared with 5-year Range[20,21]



Across the U.S., the abundance of natural gas contributed to record demand for gas by power generators during the 2011 summer period, and during the prior 2010/2011 winter season. The U.S. Energy Information Administration (EIA) expects almost no reduction in total U.S. gas consumption during the 2012/2013 winter season, since slightly lower space-heating needs are being offset by slightly higher consumption for manufacturing and power generation.

Natural gas production has fluctuated with small increases and decreases during 2012 as measured by EIA, which is in contrast to the strong upward growth seen between 2009 and 2011. Current projections by EIA indicate total natural gas production growth will slow to 2.6 Bcf/day in 2012 and 0.4 Bcf/day in 2013. The reduction in drilling activity for natural gas is offset by growth in production from liquids-rich natural gas production areas such as the Eagle Ford and wet areas of the Marcellus Shale, and associated gas from the growth in domestic crude oil production.

While NPCC-New England is not the only region in the North America facing potential gas dependency and electric reliability issues, the issues are exacerbated there because of the swift switch to gas as the fuel of choice for power and relatively small Firm pipeline capacity commitments from generators.

Most generators do not have Firm gas supply or transportation contracts and purchase remaining transportation from capacity owners—typically local distribution companies. On days of extreme winter temperatures, single-fuel, natural gas-fired capacity is at risk of being unavailable due to fuel constraints primarily because all of the capacity entitlements from Firm capacity holders—the local distribution companies—are being scheduled as contracted. This puts the area not only at risk of a curtailment event, but also due to interruptions of multiple generators. Added to that is the fact that the region is the termination point for most north- or east-bound pipes.

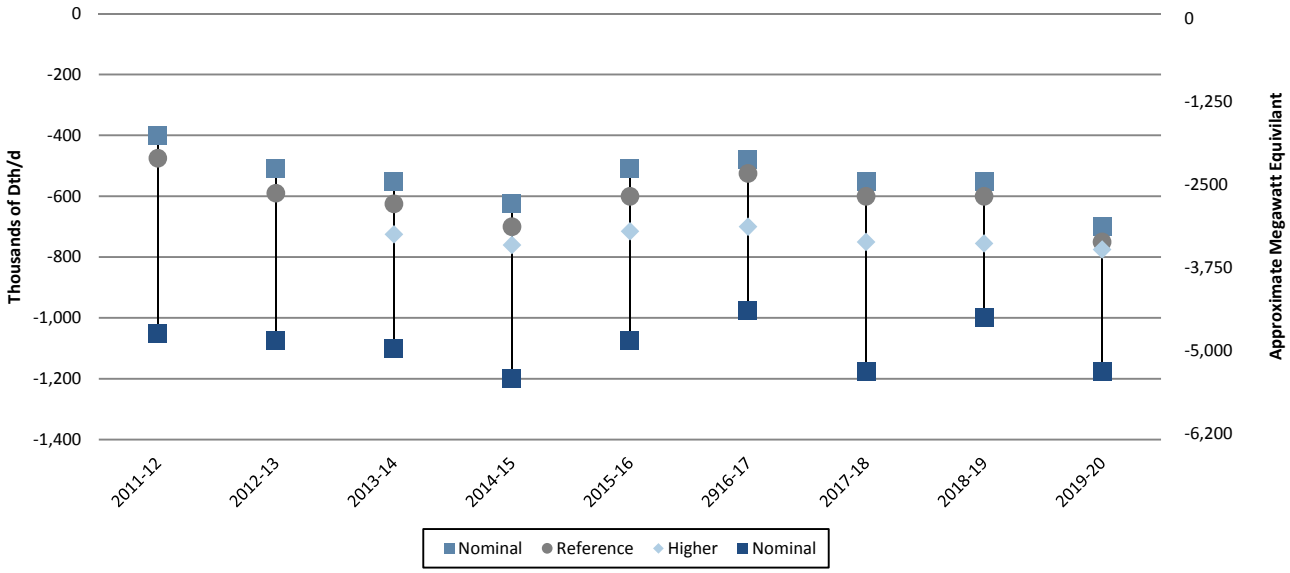
Further burdening mitigation efforts is the lack of options—no underground bulk gas storage options exist due to the geologic characteristics of New England and most of New England's gas-fired power plants are not dual-fuel capable.[22,23]

In a recent ISO-NE study, a high-level assessment was performed, determining whether the pipeline infrastructure (and available capacity) is sufficient to meet the demands of electric generators, and thus, the reliability of the bulk power system.[24] The report concluded the following for winter peak conditions:

[20] Both Y-axes represent Billion Cubic Feet of Natural Gas
[21] The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2007 through 2011. Source: Form EIA-912, "Weekly Underground Natural Gas Storage Report."
[22] The Basics of Underground Natural Gas Storage, U.S. Energy Information Administration, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html
[23] As of late October 2012, regional inventories of distillate fuel oils (i.e. jet fuel, kerosene, diesel and No. 2 fuel oil) are considerably down from their 5-year historical averages. With the restarting of several east coast refineries, this situation is expected to improve prior to winter.
[24] *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*, June 2012 :http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public.pdf

- New England's gas delivery system is already in a very tight balance on a winter design day,[25] even before any future gas demand growth is factored in.
- For the 2012/2013 winter peak, conditions could cause a capacity deficit approximately between 2,300 MW and 4,200 MW (range represents nominal to maximum Firm customer pipeline demand).
- On winter design days, supplies available to electric generators are usually below the fuel "reserve margin" (the amount of gas pipeline capacity that would be needed to supply "operating reserve" units on the power system), indicating that there is not enough supply for generators with interruptible pipeline service.
- While the probability that a gas-sector "design day" will occur is lower than the probability that a 90/10 electric load will occur, there is still a significant potential for supply shortages for gas generators with non-Firm supplies over the next ten years.

Figure 8: New England Study Shows Potential for Capacity Deficits during Winter Peak Seasons



In the fall of 2010, ISO New England (ISO-NE) launched a Strategic Planning Initiative[26] to focus the region on developing solutions to five identified risks to the continued reliable, efficient operation of the bulk power system and wholesale electricity markets.[27] One of these risks is related to increased reliance on natural gas-fired capacity. Addressing this risk has become a priority, given the reliability challenges that are already in evidence.

The continuing efforts of the New England Planning Coordinator are encouraging and provides preparation and mitigation solutions for this winter, as well as a roadmap for future enhancements; however, the amount of flexibility system operators can technically achieve in a severe weather event that affects natural gas transportation is limited.

Most of the assessment areas have indicated that there are no specific fuel deliverability issues for the upcoming winter at this time. However, the increased reliance on natural gas as one of the leading fuels used for both intermediate and peaking capacity has prompted NERC to monitor reliability considerations associated with natural gas supply and delivery.

[25] While the exact conditions used for design day planning vary among the region's individual local distribution companies, the design day criterion is generally the coldest day in the past 30 to 50 years. As a result, the local distribution companies design day standard is much more stringent than one-in-ten year extreme demand ("90/10") the BPS generally uses for its resource adequacy planning.
[26] http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/index.html
[27] DRAFT Addressing Gas Dependence (discussion paper), July 2012: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf

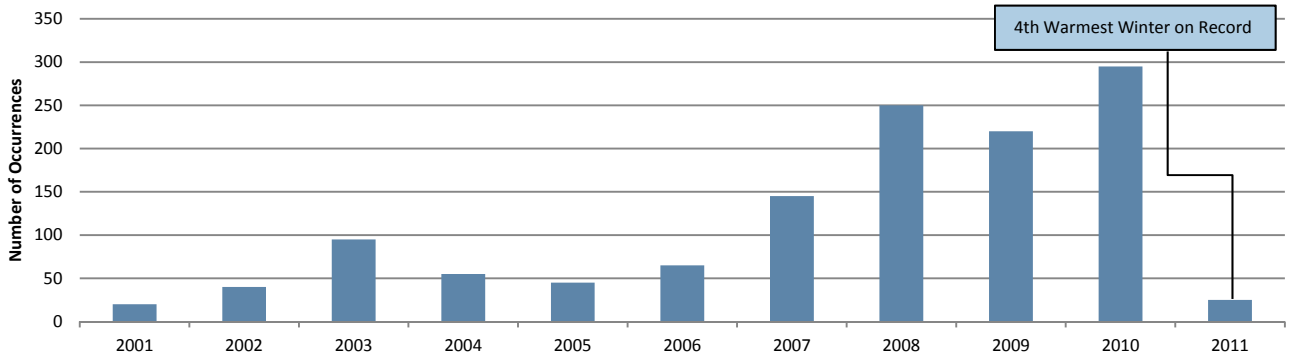
As shown in the NERC Phase I study on increasing gas dependencies, reliability challenges are more likely to occur during the winter season.

While electric generation is generally able to schedule and secure gas during the summer to meet seasonal peak demand, this flexibility decreases during winter months when pipelines tend to peak and Firm transportation customers have scheduled their full entitlements. Cold weather can also be responsible for increased infrastructure and/or supply disruptions, generally caused by freezing. Risks to gas wellheads, generators, and pipeline infrastructure due to freezing can expose the electric industry to significant capacity shortages.

It is important to understand that while Firm gas transportation significantly decreases the likelihood that fuel delivery will be curtailed, extreme events, such as well-head freeze-offs causing decreased gas production (a "force majeure" event), could potentially lead to common-mode failures of a significant amount of gas-fired generators. Additionally, pipeline customers who's gas use is designated as "human use" (typically, local distribution companies and some commercial customers) always receive priority over electric generation, which during emergencies and restoration efforts, can have an impact to gas-fired generation—even those that have Firm capacity rights.

Part of on-going NERC efforts includes analyzing generator past-performance through the NERC Generator Availability Data System (GADS).[28] GADS data is important in tracking gas-fired generator availability rates to determine whether trends in forced outages are increasing. Specifically, GADS data shows the capacity and number of occurrences of forced outages due to a "lack of fuel" cause code.[29] An analysis of the prior ten years shows an increasing trend in forced outages, with the exception of 2011.

Figure 9: 2001-11 GADS NERC-Wide Gas-Fired Generator Outages Due to Loss of Fuel Cause Codes



Dual fuel capabilities and a variety of storage options may help bridge the gap between the uncertainties of gas availability during extreme events and maintaining a reliable source of capacity available to meet seasonal peak demands. Ultimately, the right balance of Firm pipeline capacity, dual-fuel capabilities, and a variety of storage options will be regionally dependent. Factors such as market structure, geography, fuel-mix, and pipeline infrastructure will determine the extent of gas dependency risks as well as what solutions are available.

Improvements in system reliability can be realized from having sufficient back up and dual fuel switching capabilities available. Obstacles to achieving such benefits include State, Federal, and Provincial environmental regulations, which effectively limit the amount of oil that can be burned, and operational preparedness for these events.

Current policies and rules that regulate back-up oil use and emissions for electric generation may need to be evaluated to ensure dual fuel capability can be maintained during emergencies or other extreme conditions. Additionally, planning

[28] NERC Generating Availability Data System (GADS) : http://www.nerc.com/page.php?cid=4|43
[29] GADS Cause Codes: http://www.nerc.com/files/Appendix_B1_Fossil_Steam_Unit_Cause_Codes.pdf

processes should consider backup fuel inventories, changes in ramp and unit power capabilities, and the time requirements for fuel switch-over. Without considering this information, the amount of available dual-fuel generation projected to be available may be overstated.

As part of this plan, accurate weather forecasts are needed so that effective preparations can be made by both system operators, generators operators, and transmission operators.

The topic of Natural-Gas and Electric Interdependency will be covered in greater detail in NERC's Phase II study of this topic, slated for public release in December 2012.

Improved Winterization in the Southwest

In early February 2011, customers in the southwest region of the United States experienced unusually cold and windy weather. Lows during the period were in the teens for five consecutive mornings and there were many sustained hours of below freezing temperatures throughout Texas and in New Mexico. Low temperatures in Albuquerque, New Mexico ranged from 7 degrees Fahrenheit to -7 degrees over the period, compared to an average high of 51 degrees and a low of 26 degrees. Dallas temperatures ranged from 14 degrees to 19 degrees, compared to an average high of 60 degrees or above and average lows in the mid-to-upper 30s. Many cities in the region would not see temperatures above freezing until February 4. In addition, sustained high winds of over 20 mph produced severe wind chill factors.

Electric entities located within the Texas Reliability Entity, Inc. (TRE), the Western Electricity Coordinating Council (WECC), and the Southwest Power Pool (SPP) were affected by the extreme weather, as were gas entities in Texas, New Mexico and Arizona. More details regarding the cold-snap outages are available in a joint FERC/NERC report.[30] Subsequent to the issuance of the August 2011 joint report, NERC issued eight 'Lessons Learned' reports. Those reports are available on the NERC website.[31]

Due to the Cold Snap in early February 2011, some regions have implemented modifications, enhancements, and/or new procedures for 2012/2013 winter season planning and preparation processes to anticipate extreme cold weather. Many of the regions that experience cold weather reported that they are well prepared for extreme conditions. To prepare for the 2012/2013 winter period, these regions take certain precautions, such as:

- Weatherizing their units;
- Testing for units that claim dual-fuel capability;
- Inspecting heaters and heat tracing equipment; and
- Testing black start units.

In the following Regional sections, preparations documenting the actions taken by the electric industry are highlighted.

ERCOT

ERCOT was one of the areas affected by the February 2011 cold snap. In response to this, ERCOT has sponsored a cold weather drill in response to the Feb 1-5, 2011 event. The sequence of events associated with the extreme cold events in 2011 in ERCOT is described in several presentations and reports available at the ERCOT and TRE websites.[32]

ERCOT recently submitted (August 8, 2012) Nodal Protocol Revision Request 473 (NPRR473)[33] to define the process for submission of generation resource weatherization information within the ERCOT Protocols. This NPRR creates a process to accommodate the legislatively mandated submission of generator emergency operations plans. Texas Utilities Code in Section 186.007 (f) Weather Emergency Preparedness Report states; "An electric generation entity within the ERCOT power region shall provide the entity's [emergency operations] plan to ERCOT in its entirety." ERCOT has previously requested these plans pursuant to its authority under paragraph (i) (2) (H) of P.U.C. SUBST. R. 25.362, Electric Reliability Council of Texas (ERCOT) Governance,[34] which requires ERCOT to provide "[a]n assessment of the reliability and adequacy of the ERCOT system during extremely cold or extremely hot weather conditions, including information regarding steps to be taken by power generation companies and utilities to prepare their assets for extreme weather events." Based on its authority under this statute and rule, NPRR473 proposes to 1) create a formal process for submission of emergency operations plans and plan updates and 2) recognize the confidential status of information contained in these plans.

[30] Outages and Curtailments During The Southwest Cold Weather Event of February 1-5, 2011, http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf
[31] Lessons Learned - Southwest Cold Weather Event, http://www.nerc.com/page.php?cid=5|393
[32] http://www.texasre.org/CPDL/Texas%20RE%20Event%20Observation%20-%20Feb%202%202011%20Winter%20Event-final.pdf, http://www.texasre.org/CPDL/2011-02-02%20EEA3%20Event%20Analysis-public_final.pdf, http://www.texasre.org/CPDL/2011-02-03%20Valley%20Load%20Shed%20Event%20Analysis-public_final_revised.pdf, http://www.ercot.com/content/news/presentations/2011/Severe%20weather%20events%20one-pager%202-8-11.pdf.
[33] http://www.ercot.com/mktrules/issues/nprr/451-475/473/index
[34] http://www.puc.state.tx.us/agency/rulesnlaws/subrules/electric/Electric.aspx

ERCOT also proposes to require separate submission of weatherization plans for each Generation Resource. Previously, the bulk of emergency operations plans submitted did not pertain to weatherization, and required ERCOT to sort through lengthy plans to identify parts that may or may not be intended to apply to weatherization procedures and imposed a substantial administrative burden.

ERCOT communication efforts also included the addition of a "grid status/conservation" feature to the ERCOT website similar to those on other ISO homepages.

ERCOT is also reviewing a process for semi-annual grid emergency drills, which will include government entities, industry, and other affected parties effectively extending the communication reach of ERCOT. The emergency drill process will include a crisis communication team structure currently being developed. ERCOT has implemented a change in handling overflow calls that may be a result of an emergency situation by creating a phone-bank made up of ERCOT internal staff.

ERCOT conducts qualification testing of Black Start Resources and proposed language changes in NPRR369[35] to allow a Resource Entity representing a contracted Black Start Resource to request that an alternate Generation Resource substitute for an originally contracted Black Start Resource if the alternate Generation Resource meets testing and verification under established qualification criteria to ensure Black Start Service. In addition to quarterly testing allowed by NPRR369, ERCOT may also schedule random testing to verify that qualified Black Start Resources are operable pursuant to Protocol Section 3.14.2(4).[36]

Pursuant to PUCT Substantive Rule 25.53, all generating entities in the ERCOT Region are required to weatherize their units. In addition, ERCOT is requesting information from resource owners for performing the analysis of winter extreme weather assessment. This is being done as per the new PUCT rule 25.362 (i) (2) (H) that requires ERCOT to submit a report on the generation adequacy under extreme weather conditions.

WECC

In mid-September 2011, WECC issued a winter weatherization readiness reminder to Generator Owner and Generator Operators' primary and alternate compliance contacts. Several Balancing Authorities (BA)[37] have indicated that their prior winter season preparation procedures were adequate and that modifications, enhancements, or new winter procedures are not needed.

Some BAs, particularly those in areas most heavily impacted by the February 2011 cold weather event report implementing more rigorous plant winterization programs. Changes implemented since the 2011 event are focused on plant freeze-up prevention (e.g., heat tracing) with less apparent need for any other changes. Particularly unaffected items include communications protocols or facilities, fuel needs/switching capabilities, black start units, and emission limitations.

Power plants subject to subfreezing weather conditions are generally equipped with various plant freeze-up prevention elements. Such facilities routinely inspect those elements and make necessary repairs and/or improvements. Entities have reported that they have seasonal preparedness procedures in place that address freeze protection facility inspection and repair work and that they follow those procedures. Some of the entities in Arizona and New Mexico have reported post-2011 improvements to either the freeze protection elements or the winter preparedness procedures related to those facilities.

Operating limit testing, potential fuel need determination, and fuel switching capability tests are routine power plant owner functions. However, performing such activities during extreme cold weather conditions is not a routine activity. One summer-peaking entity reported that it does periodically perform tests during cold weather conditions to ensure plant availability. An entity in the area most severely impacted by the February 2011 cold snap reported that it undertook a

[35] http://www.ercot.com/mktrules/issues/nprr/351-375/369/index
[36] http://www.ercot.com/mktrules/nprotocols/current
[37] There are a number of Generator Owners and Generator Operators in the WECC Region that are also registered as Balancing Authorities in the NERC Compliance Registry.

review of generator unit and plant equipment temperature design limitations. It also reviewed its plant performance, including auxiliaries, during the 2011 extreme cold snap and used that information to determine which devices/equipment would need additional enhancements. This work will be completed prior to the upcoming winter season.

Entities within WECC also have established generator unit rating procedures as well as procedure for establishing near-term expected output capability. No WECC entities have reported enhancements to those procedures relative to real power output capability in advance of anticipated extreme cold weather. However, one entity in the area most severely impacted by the February 2011 cold weather event reported that it is evaluating implementing output forecasts based on forecasted weather conditions.

Several entities reported that one or more of the 2011 cold weather event lessons learned have been incorporated into their winter preparation procedures. Responses from several other entities indicate that their winter preparation procedures may be revised prior to the start of the winter season. As one might expect, the bulk of the procedural changes are concentrated in the geographic area most severely impacted by the 2011 cold weather event.

SPP

The SPP RTO footprint experiences harsh winter weather conditions that include temperatures below freezing, sleet and snow every year. As a result, generator and transmission facility owners prepare for these conditions each year.

However, several entities in the SPP RTO footprint did experience some problems during the extreme winter conditions that occurred in February 2011. As a result, SPP RTO and individual members reviewed their existing winter weather preparation plans and the Southwest Cold Weather Event recommendations and have made enhancements where needed.

To prepare generators for the winter period, beginning in late September through the month of October, SPP RTO generation owners assess their Winter Preparedness procedures. These procedures include the inspection of all heat trace equipment, windbreaks, heaters, and complete all winterization checklist procedures. If any equipment is found to be damaged or faulty, temporary freeze protection methods will be put into place until the equipment fix is completed. Safety departments also review the winter weather safety procedures for personnel and all safety equipment needed in severe winter conditions.

SPP RTO Members are required to test their generators in accordance with SPP Criteria 12,[38] which includes the periodic testing of generators operating limits and fuel switching capabilities. SPP RTO Members perform seasonal power flow studies, and while there are numerous dual fuel capable units within the SPP RTO area, there are no critical system loads dependent on a single source of generation fuel. Some RTO Members monitor a 10-day forecast issued by the National Weather Service and ensure that adequate fuel supplies are on hand to handle any extreme cold weather events that may impact delivery.

Others Areas

Regions that weren't affected by the cold snap, such as FRCC and SERC, incorporated the lessons learned and made modifications to their policies and procedures to accommodate cold-weather events.

Although FRCC does not regularly experience harsh winter weather the majority of Generator Owners and Generator Operators within the FRCC Region indicated through a Regional survey that their cold weather preparatory plans were adequate. In addition, the FRCC held a cold weather preparation meeting to review lessons learned and develop guidelines and training for winter preparation. The most common areas of improvement that have now been incorporated among owners and operators covered the flexibility of dual-fueled generators to switch between primary and alternate fuel

[38] SPP Criteria: http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices%20Jan.%202012.pdf

sources (e.g., natural gas or fuel oil); for the consideration of emission limitations and their impact to operations during extreme cold weather events; and the increased training of staff on new and existing processes and preparedness procedures.

In SERC-E, entities already have existing procedures in place to address potential reliability concerns. To prepare generators for the upcoming winter, entities report that various stations have existing procedures to perform inspections on heaters and heat tracing equipment each fall. Generating unit capability is measured on a regular basis to conFirm that each unit is capable of providing rated output. Any limitations are communicated promptly to entity operations staff. For those units with fuel switching capability, fuel systems are tested annually during winter months to ensure fuel switching can be accomplished. Fuel inventories are monitored and increased as necessary, to ensure an adequate supply.

Entities in the area are currently performing detailed reviews of the recommendations from the February 1-5, 2011 cold weather event and providing responses to various regulatory agencies on the evaluation of their system. Although many of the recommendations helped to reinforce plans and procedures already in place, some entities have taken additional steps to improve their plans. Entity improvements include; the testing of black start units in cold weather, providing electric service for compression stations that support gas service for generation facilities, and establishing protocol to protect this electrical supply.

Projected Demand, Resources, and Reserve Margins

Winter 2012/2013 Non-Coincident Peak

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins			NERC
Country / Assessment Area	Net Internal	Total Internal	Existing-Certain	Anticipated	Prospective	Existing-Certain	Anticipated	Prospective	Reference
ERCOT	51,461	52,909	73,563	73,563	73,563	42.95%	42.95%	42.95%	13.75%
FRCC	43,558	46,864	58,405	57,605	58,675	34.09%	32.25%	34.71%	15.00%
MISO	72,187	75,085	109,541	109,541	121,193	51.75%	51.75%	67.89%	15.40%
MRO-MAPP	5,137	5,512	6,833	6,901	7,134	33.03%	34.36%	38.89%	15.00%
NPCC-New England	21,392	22,355	35,755	35,882	35,882	67.14%	67.74%	67.74%	15.00%
NPCC-New York	24,832	24,832	33,841	33,841	33,841	36.28%	36.28%	36.28%	16.00%
PJM	130,222	130,222	182,467	182,467	182,467	40.12%	40.12%	40.12%	15.60%
SERC-E	41,647	43,150	53,348	55,737	55,789	28.10%	33.83%	33.96%	15.00%
SERC-N	43,489	45,081	57,595	57,595	63,885	32.44%	32.44%	46.90%	15.00%
SERC-SE	43,738	45,620	63,619	64,840	67,253	45.46%	48.25%	53.76%	15.00%
SERC-W	19,997	20,008	34,193	34,193	39,195	70.99%	70.99%	96.00%	15.00%
SPP	35,079	35,810	80,708	80,337	80,337	130.08%	129.02%	129.02%	13.60%
WECC-CAMX (US)	1,463	1,463	2,504	2,504	2,504	71.16%	71.16%	71.16%	10.70%
WECC-NWPP (US)	43,215	43,549	51,737	52,275	52,275	19.72%	20.96%	20.96%	18.00%
WECC-RMRG	9,477	9,744	13,775	14,155	14,155	45.35%	49.36%	49.36%	15.70%
WECC-SRSG	17,971	18,239	36,244	36,288	36,288	101.68%	101.93%	101.93%	13.90%
TOTAL-UNITED STATES	604,863	620,442	894,129	897,724	924,436	47.82%	48.42%	52.83%	15.00%
MRO-Manitoba Hydro	4,182	4,407	5,414	5,414	5,414	29.46%	29.46%	29.46%	12.00%
MRO-SaskPower	3,426	3,512	3,901	3,901	4,086	13.86%	13.86%	19.25%	13.00%
NPCC-Maritimes	5,076	5,246	6,607	6,607	6,607	30.17%	30.17%	30.17%	15.00%
NPCC-Ontario	22,087	22,087	31,357	32,719	33,349	41.97%	48.14%	50.99%	20.40%
NPCC-Québec	35,713	37,543	41,619	41,619	41,619	16.54%	16.54%	16.54%	9.60%
WECC-NWPP (CAN)	22,283	22,339	25,507	25,758	25,758	14.47%	15.59%	15.59%	14.00%
TOTAL-CANADA	92,767	95,134	114,406	116,018	116,833	23.33%	25.06%	25.94%	10.00%
CAMX-MX	38,191	39,187	60,386	60,466	60,466	58.12%	58.33%	58.33%	11.00%
TOTAL-MEXICO	38,191	39,187	60,386	60,466	60,466	58.12%	58.33%	58.33%	11.00%
TOTAL-NERC	**735,821**	**754,764**	**1,068,920**	**1,074,208**	**1,101,735**	**45.27%**	**45.99%**	**49.73%**	**58.30%**

December 2012

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins			NERC
Country / Assessment Area	Net Internal	Total Internal	Existing-Certain	Anticipated	Prospective	Existing-Certain	Anticipated	Prospective	Reference
ERCOT	51,461	52,909	73,563	73,563	73,563	42.95%	42.95%	42.95%	13.75%
FRCC	34,818	37,817	58,405	56,986	58,057	67.74%	63.67%	66.74%	15.00%
MISO	72,187	75,085	109,541	109,541	121,193	51.75%	51.75%	67.89%	15.40%
MRO-MAPP	5,059	5,275	6,880	6,888	7,121	35.99%	36.14%	40.75%	15.00%
NPCC-New England	20,669	21,632	35,442	35,569	35,569	71.48%	72.09%	72.09%	15.00%
NPCC-New York	24,832	24,832	33,301	33,301	33,301	34.11%	34.11%	34.11%	16.00%
PJM	126,401	126,401	182,467	182,467	182,467	44.36%	44.36%	44.36%	15.60%
SERC-E	38,607	40,143	53,378	54,718	54,770	38.26%	41.73%	41.87%	15.00%
SERC-N	39,046	40,111	57,595	57,595	63,885	47.51%	47.51%	63.62%	15.00%
SERC-SE	38,913	40,670	63,793	64,093	66,506	63.94%	64.71%	70.91%	15.00%
SERC-W	19,715	19,726	34,383	34,383	39,195	74.40%	74.40%	98.81%	15.00%
SPP	35,079	35,810	80,708	80,337	80,337	130.08%	129.02%	129.02%	13.60%
WECC-CAMX (US)	1,455	1,455	3,010	3,010	3,010	106.87%	106.87%	106.87%	10.70%
WECC-NWPP (US)	43,215	43,549	51,737	52,275	52,275	19.72%	20.96%	20.96%	18.00%
WECC-RMRG	9,377	9,643	12,244	12,624	12,624	30.57%	34.63%	34.63%	15.70%
WECC-SRSG	17,971	18,239	36,244	36,288	36,288	101.68%	101.93%	101.93%	13.90%
TOTAL-UNITED STATES	578,804	593,297	892,691	893,637	920,160	54.23%	54.39%	58.98%	15.00%
MRO-Manitoba Hydro	4,092	4,317	5,401	5,401	5,401	31.99%	31.99%	31.99%	12.00%
MRO-SaskPower	3,426	3,512	3,901	3,901	4,086	13.86%	13.86%	19.25%	13.00%
NPCC-Maritimes	4,739	4,894	6,574	6,574	6,574	38.73%	38.73%	38.73%	15.00%
NPCC-Ontario	21,693	21,693	30,299	31,872	32,352	39.67%	46.92%	49.13%	20.40%
NPCC-Québec	32,939	34,769	41,586	41,586	41,586	26.25%	26.25%	26.25%	9.60%
WECC-NWPP (CAN)	22,283	22,339	25,507	25,758	25,758	14.47%	15.59%	15.59%	14.00%
TOTAL-CANADA	89,172	91,524	113,269	115,092	115,757	27.02%	29.07%	29.81%	10.00%
CAMX-MX	38,191	39,187	60,386	60,466	60,466	58.12%	58.33%	58.33%	11.00%
TOTAL-MEXICO	38,191	39,187	60,386	60,466	60,466	58.12%	58.33%	58.33%	11.00%
TOTAL-NERC	**706,167**	**724,008**	**1,066,345**	**1,069,196**	**1,096,383**	**51.00%**	**51.41%**	**55.26%**	**58.30%**

Winter 2012/2013 Coincident Peak: January 2013

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins			NERC
Country / Assessment Area	Net Internal	Total Internal	Existing-Certain	Anticipated	Prospective	Existing-Certain	Anticipated	Prospective	Reference
ERCOT	49,328	50,776	74,051	74,051	74,051	50.12%	50.12%	50.12%	13.75%
FRCC	43,558	46,864	58,405	57,605	58,675	34.09%	32.25%	34.71%	15.00%
MISO	72,187	75,085	109,541	109,541	121,193	51.75%	51.75%	67.89%	15.40%
MRO-MAPP	5,137	5,512	6,833	6,901	7,134	33.03%	34.36%	38.89%	15.00%
NPCC-New England	21,392	22,355	35,755	35,882	35,882	67.14%	67.74%	67.74%	15.00%
NPCC-New York	24,832	24,832	34,347	34,347	34,347	38.32%	38.32%	38.32%	16.00%
PJM	130,222	130,222	182,467	182,467	182,467	40.12%	40.12%	40.12%	15.60%
SERC-E	41,647	43,150	53,348	55,737	55,789	28.10%	33.83%	33.96%	15.00%
SERC-N	43,489	45,081	57,595	57,595	63,885	32.44%	32.44%	46.90%	15.00%
SERC-SE	43,738	45,620	63,619	64,840	67,253	45.46%	48.25%	53.76%	15.00%
SERC-W	19,997	20,008	34,193	34,193	39,195	70.99%	70.99%	96.00%	15.00%
SPP	35,079	35,810	80,708	80,337	80,337	130.08%	129.02%	129.02%	13.60%
WECC-CAMX (US)	1,463	1,463	2,504	2,504	2,504	71.16%	71.16%	71.16%	10.70%
WECC-NWPP (US)	41,444	41,856	49,060	49,632	49,632	18.38%	19.76%	19.76%	18.00%
WECC-RMRG	9,477	9,744	13,775	14,155	14,155	45.35%	49.36%	49.36%	15.70%
WECC-SRSG	17,573	17,851	35,505	35,549	35,549	102.04%	102.29%	102.29%	13.90%
TOTAL-UNITED STATES	600,561	616,228	891,707	895,336	922,048	48.48%	49.08%	53.53%	15.00%
MRO-Manitoba Hydro	4,182	4,407	5,414	5,414	5,414	29.46%	29.46%	29.46%	12.00%
MRO-SaskPower	3,424	3,510	3,901	3,901	4,100	13.92%	13.92%	19.74%	13.00%
NPCC-Maritimes	5,076	5,246	6,607	6,607	6,607	30.17%	30.17%	30.17%	15.00%
NPCC-Ontario	22,087	22,087	31,357	32,719	33,349	41.97%	48.14%	50.99%	20.40%
NPCC-Québec	35,713	37,543	41,619	41,619	41,619	16.54%	16.54%	16.54%	9.60%
WECC-NWPP (CAN)	21,985	21,985	25,132	25,355	25,355	14.31%	15.33%	15.33%	14.00%
TOTAL-CANADA	92,467	94,778	114,030	115,615	116,444	23.32%	25.03%	25.93%	10.00%
CAMX-MX	35,986	37,111	57,792	58,370	58,370	60.60%	62.20%	62.20%	11.00%
TOTAL-MEXICO	35,986	37,111	57,792	58,370	58,370	60.60%	62.20%	62.20%	11.00%
TOTAL-NERC	**729,014**	**748,118**	**1,063,529**	**1,069,321**	**1,096,863**	**45.89%**	**46.68%**	**50.46%**	**58.30%**

February 2013

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins			NERC
Country / Assessment Area	Net Internal	Total Internal	Existing-Certain	Anticipated	Prospective	Existing-Certain	Anticipated	Prospective	Reference
ERCOT	43,617	45,065	71,737	71,737	71,737	64.47%	64.47%	64.47%	13.75%
FRCC	35,393	38,550	58,405	57,614	58,684	65.02%	62.78%	65.81%	15.00%
MISO	72,187	75,085	109,541	109,541	121,193	51.75%	51.75%	67.89%	15.40%
MRO-MAPP	4,994	5,335	6,834	6,902	7,135	36.85%	38.21%	42.87%	15.00%
NPCC-New England	20,891	21,854	34,536	34,663	34,663	65.32%	65.92%	65.92%	15.00%
NPCC-New York	24,832	24,832	33,841	33,841	33,841	36.28%	36.28%	36.28%	16.00%
PJM	125,061	125,061	182,467	182,467	182,467	45.90%	45.90%	45.90%	15.60%
SERC-E	38,880	40,382	53,348	55,737	55,789	37.21%	43.35%	43.49%	15.00%
SERC-N	40,355	41,520	57,596	57,596	63,886	42.72%	42.72%	58.31%	15.00%
SERC-SE	41,273	43,153	63,619	64,840	67,253	54.14%	57.10%	62.95%	15.00%
SERC-W	20,165	20,176	34,193	34,193	39,195	69.57%	69.57%	94.37%	15.00%
SPP	35,079	35,810	80,708	80,337	80,337	130.08%	129.02%	129.02%	13.60%
WECC-CAMX (US)	1,432	1,432	2,735	2,735	2,735	90.99%	90.99%	90.99%	10.70%
WECC-NWPP (US)	40,035	40,326	51,535	52,080	52,080	28.72%	30.09%	30.09%	18.00%
WECC-RMRG	9,232	9,500	14,108	14,488	14,488	52.82%	56.93%	56.93%	15.70%
WECC-SRSG	16,742	17,052	34,263	34,307	34,307	104.65%	104.92%	104.92%	13.90%
TOTAL-UNITED STATES	570,167	585,133	889,466	893,077	919,790	56.00%	56.63%	61.32%	15.00%
MRO-Manitoba Hydro	4,106	4,331	5,417	5,417	5,417	31.93%	31.93%	31.93%	12.00%
MRO-SaskPower	3,392	3,478	3,907	3,907	4,083	15.17%	15.17%	20.37%	13.00%
NPCC-Maritimes	5,023	5,199	6,613	6,613	6,613	31.66%	31.66%	31.66%	15.00%
NPCC-Ontario	21,813	21,813	30,373	31,775	32,455	39.25%	45.67%	48.79%	20.40%
NPCC-Québec	34,338	36,168	41,341	41,330	41,330	20.39%	20.36%	20.36%	9.60%
WECC-NWPP (CAN)	20,912	20,912	24,196	24,415	24,415	15.70%	16.75%	16.75%	14.00%
TOTAL-CANADA	89,584	91,901	111,847	113,457	114,313	24.85%	26.65%	27.61%	10.00%
CAMX-MX	35,080	36,232	56,433	57,009	57,009	60.87%	62.51%	62.51%	11.00%
TOTAL-MEXICO	35,080	36,232	56,433	57,009	57,009	60.87%	62.51%	62.51%	11.00%
TOTAL-NERC	**694,831**	**713,265**	**1,057,746**	**1,063,543**	**1,091,112**	**52.23%**	**53.07%**	**57.03%**	**58.30%**

Regional Reliability Assessments – Summary

The purpose of the following sections is to present the 2012/2013 winter projections for the reliability, resources, demand, and transmission infrastructure within each of the NERC Assessment Areas. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data. Resource availability and the development of expected resources are all included in the assessments and represents the capacity that is being planned to serve peak demand.

Individual assessment area details are available from NERC upon request.[39]

[39] Send requests to esd@nerc.net.

ERCOT

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**52,909**
Load-Modifying Demand Response	1,448
Net Internal Demand	**51,461**

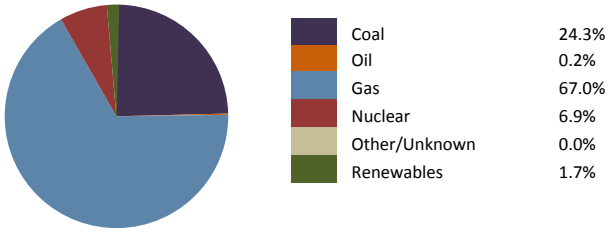
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	53,303
Actual Demand	50,969

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	281
Existing-Certain and Future-Planned Capacity	73,282
Anticipated Resources	**73,563**
Anticipated Reserve Margin (%)	**42.95%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**73,563**
Prospective Reserve Margin (%)	**42.95%**
NERC Reference Margin Level (%)	**13.75%**

Assessment Area Capacity Mix



Planning Reserve Margins

The Anticipated Reserve Margin is projected to be 42.95 percent for the 2012/2013 winter season. This estimate is above the minimum 13.75 percent Target Reserve Margin level for ERCOT. The ERCOT minimum Target Reserve Margin, referred to as the Planning Reserve Margin in ERCOT's documentation, of 13.75 percent is based on Loss-of-Load Events (LOLEv) analysis of no more than 0.1 events per year based on an updated probabilistic study completed in2010.[40]

Use of an extreme temperature assumption (90/10 scenario) to produce a revised load forecast produces a peak demand forecast for the 2012/2013 winter season of 58,138 MW. The 90/10 forecast is 10 percent higher than the average (50/50) weather profile which results in an Existing Certain Reserve Margin of 26.5 percent.

A 925 MW thermal generation plant that was scheduled to be available for the summer of 2012 was delayed and is not expected to be available until March 2013. Even without this unit, the ERCOT Region is expected to have adequate resources for the 2012/2013 winter.

Demand

Several areas in the ERCOT Region have and are experiencing significant load growth due to increased petroleum extraction activities. ERCOT is working with affected transmission owners to develop transmission improvements to serve these increased loads reliably. Although the load growth is significant at specific stations, the aggregate load growth from these activities is not expected to have a significant impact on system-wide resource adequacy.

According to the ERCOT demand forecast, Total Internal Demand is forecasted to be 52,909 MW based on average winter weather conditions. This is a decrease from the forecasted peak of 53,562 MW for the winter season of 2011 – 2012, but an increase from the actual 2011/2012 winter system peak of 50,969 MW. The growth rate from last winter's actual peak load (50,969 MW) to this winter's forecasted peak load (52,909 MW) is 3.8 percent. The growth rate from last winter's forecasted peak load (53,562 MW) to this winter's forecasted peak load (52,909 MW) is a negative rate of 1.2 percent.

Demand-Side Management

[40] http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip.

ERCOT expects an incremental 119 MW of energy efficiency improvements across the ERCOT Region for the 2012/2013 winter season. This incremental energy efficiency is the result of recent energy efficiency improvements installed by transmission owners as a result of legislative requirements.

Load Resources (LR)[41] providing Responsive Reserve Service[42] are anticipated to provide an average of approximately 946 MW of dispatchable, contractually committed Demand-Side Load as a Capacity Resource for the 2012/2013 winter season. This set of loads is the only demand-side resource providing ancillary services to the ERCOT grid.

ERCOT's Emergency Response Service (ERS), which is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary "Firm" load, represents Demand-Side Contractually Interruptible (Curtailable) Demand. ERCOT has procured 502 MW of ERS Load for the ERS contract period of October 2012 to January 2013.

Together these two programs (LR and ERS) would reduce winter peak demand by approximately 2.8 percent if activated. Measurement and verification procedures for these programs are defined in the Performance Monitoring section of the ERCOT Protocols.[43]

Generation

Existing-Certain generation capacity in ERCOT, as reported by generation owners, for the 2012/2013 winter season is expected to be 73,282 MW.

A total of 1,357 MW of wind generation capacity (118 MW effective on peak due to the Effective Load Carrying Capability (ELCC) of wind resources) is expected to be added during the 2012/2013 winter season. Also, 36 MW of battery storage resources are expected to be added during the 2012/2013 winter season.

There are no units classified as Existing-Other in ERCOT, while there are 3,756 MW of Inoperable Resources (mothballed capacity) in ERCOT for the 2012/2013 winter season. This is an increase of 1,810 MW from the 1,946 MW of mothballed capacity noted during the ERCOT 2012 Summer Assessment. The Inoperable Resources consist of units that are classified as mothballed by their owners and are not expected to be available during the 2012/2013 winter season. This capacity is not counted toward reserves during the 2012/2013 winter season. No additional unit retirements, project deferments, derates or other capacity reductions are expected prior to or during the 2012/2013 winter season.

No significant change is expected in the availability of "behind-the-meter" generation for the 2012/2013 winter season. There is 3,168 MW of "switchable" generation that can operate in the ERCOT system or in adjacent (not synchronously interconnected) regions. ERCOT counts all of this generation capacity as available, except for 317 MW, which is obligated to serve load outside of the ERCOT Region.

Capacity Transactions

The ERCOT Region is a separate Interconnection with only asynchronous ties to Southwest Power Pool (SPP) and Mexico's Comision Federal de Electricidad (CFE). As such, ERCOT does not share reserves with other Regions. There are two asynchronous ties between ERCOT and SPP with a total of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico with a total of 280 MW of transfer capability.

The ERCOT Region does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements, it may request external resources for emergency services over the asynchronous ties or by block transfer of discrete loads. For the 2012/2013 winter, ERCOT has 458 MW of imports from SPP and 140 MW from CFE. Of the imports from SPP, 48 MW is tied to a long-term contract for a purchase of Firm power from specific generation. The remaining imports of 410 MW from SPP and 140 MW from CFE represent one-half of the asynchronous tie

[41] See Section 3.17 and 3.18 of http://www.ercot.com/content/mktrules/nprotocols/current/03-030112_Nodal.doc; Previously referred to as Load Acting as Resources (LaaRs).
[42] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.
[43] http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc

transfer capability and are included to reflect emergency support arrangements. Several SPP members own 317 MW of a power plant located in the ERCOT Region, resulting in a Firm export of that amount from ERCOT to SPP.

Transmission

Several significant transmission improvements are expected to be completed before February 2013 in the ERCOT Region. These are expected to meet reliability needs or reduce market congestion prior to or during the 2012/2013 winter season.[44]

Operations

There are no significant or unusual operating conditions that could significantly affect system operations for the 2012/2013 winter.

Vulnerability Assessment

Currently available information indicates that it is unlikely that water availability will limit generation resources during the 2012/2013 winter season.

In the ERCOT Region, generator owners and operators are responsible for their own fuel supply and transportation arrangements. In addition, ERCOT is a member of the Texas Energy Reliability Council; this group coordinates between the gas and electric industries and, if necessary, allocates deliveries of natural gas during periods of high demand. In the event of forecasted extreme weather and possible fuel curtailments, ERCOT may request fuel capability information from generation entities to prepare operationally for potential curtailments.

ERCOT has recently received a contractor's analysis of potential impacts of gas transportation limitations on grid reliability. This study found that any such impacts are unlikely and expected to be minor.[45] Additionally, coal transportation issues are not expected to have a reliability impact on the ERCOT Region during the upcoming winter season.

As a result of the recent ruling by the D.C. Court of Appeals vacating the Cross-State Air Pollution Rule, it is not expected that environmental regulations will have an impact on availability of generation resources during the upcoming 2012/2013 winter season. There are no unit outages for installation of retrofit equipment expected to occur during the upcoming 2012/2013 winter.

[44] Additional details on transmission projects can be found in the "Report on Existing and Potential Electric System Constraints and Needs" located on the following website: http://www.ercot.com/content/news/presentations/2012/2011 percent20Constraints percent20and percent20Needs percent20Report.pdf

[45] http://www.ercot.com/content/meetings/board/keydocs/2012/0221/Item_06_-_Gas_Risk_Study.zip

FRCC

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**46,864**
Load-Modifying Demand Response	3,306
Net Internal Demand	**43,558**

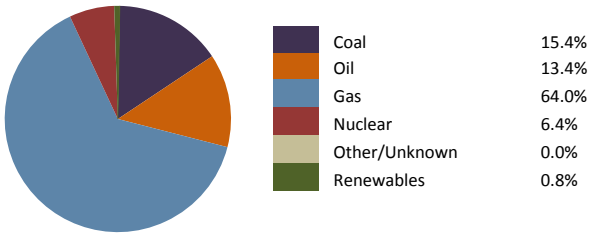
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	47,613
Actual Demand	39,924

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	2,212
Existing-Certain and Future-Planned Capacity	55,393
Anticipated Resources	**57,605**
Anticipated Reserve Margin (%)	**32.25%**
Existing-Other and Future-Other Capacity	1,071
Prospective Resources	**58,675**
Prospective Reserve Margin (%)	**34.71%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

The FRCC is projecting adequate Reserve Margins during the upcoming 2012/2013 winter. A 15 percent Reserve Margin criteria is required by the Florida Public Service Commission for the FRCC Region for all planning horizons. Based on the expected load and generation capacity, the calculated Anticipated Reserve Margin for the winter of 2012/2013 is 32.2 percent when Load Management and Interruptible loads are treated as a demand reduction.

Factors impacting the winter Reserve Margin include a 3 to 4 year period of weak economic demand resulting in more than adequate Reserve Margins. The weakness in the housing market, namely the tight credit levels, the drop in housing values below the outstanding mortgage levels, and lack of employment growth, all have hampered the overall mobility of residences to relocate to other areas. A rebound in the economy could potentially increase the demand, energy, and load projections that could result in realignment with previous projections.

Demand

Last year's peak demand forecast for the winter of 2011/2012 was 47,613 MW, which was 7,689 MW (19.3 percent) above the 2011/2012 actual demand of 39,924 MW. The FRCC Assessment Area is forecasted to reach its 2012/2013 winter non-coincident peak total internal demand of 46,864 MW in January 2013 representing a projected demand increase of 17.4 percent above the unusually mild winter demand experienced during January of the 2011/2012 winter season. This projection for the 2012/2013 winter peak demand is consistent with historical weather-normalized FRCC demand growth yet it is 1.6 percent lower than last year's winter forecast of 47,613 MW.

The small decrease in the 2012/2013 projected winter peak demand is attributed to lower expected consumption and economic activity compared to assumptions used in the previous projection. Load growth across individual Load Serving Entities (LSE) in the Region is proportional with the level of load growth seen across the FRCC Assessment Area.

Demand-Side Management

The projected 2012/2013 winter peak Total Internal Demand includes 3,306 MW of potential demand reductions from the use of load management (2,727 MW) and interruptible demand (579 MW).

Generation

The FRCC Region counts on 56,193 MW of Existing - Certain resources, of which 44 MW are hydro and 339 MW are Biomass. Potential solar capacity is projected to be 49.3 MW; however, most of this capacity is de-rated with approximately 1.7 MW considered as a Firm resource available during peak demand, with the remainder being used as an energy-only

resource. Derated hydro capacity will be 11 MW. There are 2,033 MW of Existing-Other member-owned capacity presently placed into Inactive Reserves, while Existing-Other merchant plant capability of 193.2 MW is potentially available as future resources for FRCC members and others.

Approximately 60 percent of the Region's annual energy consumption and seasonal demand requirements are supplied by generation whose primary fuel source is natural gas. Nearly half of the generation fueled by natural gas has dual fuel capability therefore reducing the risk of these resources not being available due to unexpected fuel supply issues.

There are no retirements planned for during the upcoming winter season, however, 765 MW of generation are scheduled to be placed into Inactive Reserves[46] near the start of the winter season having functioned earlier in the year as replacement capacity for unit upgrades that have been completed. These activities are not expected to have an impact on ensuring that adequate generation will be available to serve load.

There are 865 MW of capacity not included in the winter forecast due to a long-term outage. This capacity is scheduled to be returned to service in late 2014. Another 822 MW of capacity is on short-term outage during the upcoming winter months, and will not be placed back into service until after the winter season.

Capacity Transactions

There are 1,340 MW of generation under Firm contract, available to be imported into the Region from the SERC-SE Assessment Area throughout the winter season, and another 872 MW of member-owned generation, which is dynamically dispatched out of the SERC-SE Assessment Area. These purchases have Firm transmission service to ensure deliverability into the FRCC Region.

The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts in place between entities within the SERC-SE Assessment Area and FRCC entities.

Transmission

Currently the FRCC Region expects to have multiple Bulk Electric System (BES) facilities out of service during the 2012/2013 winter season. The current planned outages are staggered as to limit the impact and exposure to the BES during the winter season. These respective outages were studied as part of the FRCC's Operational Seasonal Study. As a result, coordinated corrective action plans were developed to ensure reliability during the 2012/2013 winter season.

FRCC Region has not identified any specific large-scale projects that are needed to maintain or enhance reliability during the 2012/2013 winter season. The FRCC's Operational Seasonal Study did identify limiting elements associated with BES facilities that will be replaced prior to the 2012/2013 winter peak. Additions to the BES within the FRCC Region are primarily related to system expansion in order to serve forecasted demands and maintain the reliability of the BES.

Operations

FRCC expects the BES to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the 2012-2012 winter peak demand. The FRCC performed a Winter Transmission Assessment and Operational Seasonal Study to assess the adequacy and robustness of the BES within the FRCC Region under expected 2012/2013 winter peak load and under anticipated system conditions (taking into account generation and transmission maintenance activities). The study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria could be successfully mitigated under normal conditions, single contingency events, and selected multiple contingency events. Based on the FRCC Winter Transmission Assessment and Operational Seasonal Study, no unusual operating conditions are expected to impact reliability for the upcoming 2012/2013 winter.

[46] IEEE 762: Inactive Reserves – "the state in which a unit is unavailable for service but can be brought back into service after some repairs in a relatively short duration of time." FRCC does include Inactive Reserves capacity in the calculation of Reserve Margins when this generation is not in commercial service.

Vulnerability Assessment

Two 800MW class units are scheduled to be unavailable during a defined period within the study horizon. Based on the FRCC Winter Transmission Assessment and Operational Seasonal Study, the unavailability of these units is not anticipated to cause any reliability concerns.

The FRCC Region does not anticipate any impacts to the seasonal plan or in operations resulting from any potential capacity reductions stemming from forthcoming environmental and/or regulatory requirements. In addition, existing operating procedures can adequately address the integration of limited amounts of variable resources for the 2012/2013 winter.

For the 2012/2013 winter season, no concerns are anticipated due to a limited fuel supply within the FRCC Region. There are no fuel availability or supply issues identified at this time. Based on recent studies, current fuel diversity, alternate fuel capability and fuel study results, the FRCC does not anticipate any fuel issues affecting resource capability during the 2012/2013 winter season.

MISO

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**75,085**
Load-Modifying Demand Response	2,898
Net Internal Demand	**72,187**

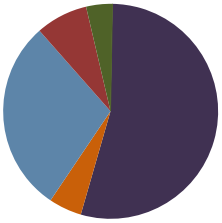
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	79,994
Actual Demand	72,739

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	3,001
Net Capacity Transactions (Firm and Expected)	2,714
Existing-Certain and Future-Planned Capacity	103,826
Anticipated Resources	**109,541**
Anticipated Reserve Margin (%)	**51.75%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**109,541**
Prospective Reserve Margin (%)	**67.89%**
NERC Reference Margin Level (%)	**15.40%**

Assessment Area Capacity Mix



Coal	54.2%
Oil	5.0%
Gas	29.1%
Nuclear	7.8%
Other/Unknown	0.0%
Renewables	3.9%

Assessment Area Highlights

Currently, MISO's membership consists of 40 Transmission Owners with $17.8 billion in transmission assets under MISO's functional control and 98 Non-transmission owners. MISO has four Balancing Authorities in the region, including the MISO Balancing Authority, and experiences its annual peak during the summer season. MISO's scope of operations encompasses 49,641 miles of transmission over 13 states and one Canadian province. MISO's Energy and Operating Reserves market includes 363 market participants serving over 38.9 million people.

MISO continues to establish reserve margin requirements for its members. For planning year 2012 MISO's System Installed Generation Planning Reserve Margin (PRMSYSIGEN) requirement on a MISO coincident load basis is 16.7 percent. The PRMSYSIGEN for the MISO Assessment Area is based on Net Internal Demand and Anticipated Capacity Resources. The anticipated Reserve Margin and Prospective Reserve Margin for the winter are 51.7 percent and 67.9 percent, respectively. These reserve margins are based on an additional 129 MW of capacity added during the 2012/2013 winter.

The forecasted Total internal peak demand for the 2012/2013 winter is 75,084 MW. Last year's forecasted peak Total Internal Demand for the 2011/2012 winter assessment period was 80,572 MW. This decrease (about 7percent percent) is due to the transfer of Duke Energy Ohio and Kentucky to PJM on Jan 1, 2012. MISO does not anticipate any significant transmission issues to impact reliability during the 2012/2013 winter.

Planning Reserve Margin

For the winter of 2012/2013 the existing certain reserve margin is 51.7 percent which exceeds MISO's Planning Reserve Margin Requirement (PRMR)[47] of 16.7 percent. The anticipated reserve margin is 57.1 percent exceeding the PRMR, and the prospective planning reserve margin of 73.9 percent exceeds the PRMR. MISO is projecting adequate Planning Reserve Margins for the 2012/2013 winter.

Demand

During last year's winter season, MISO experienced an instantaneous peak of 74,011MW on December 6th hour ending 19 EST. The instantaneous load is the highest value metered during the peak hour. The 2011/2012 winter peak demand was

[47] For planning year 2012 MISO's System Installed Generation Planning Reserve Margin (PRMSYSIGEN) requirement on a MISO coincident load basis is 16.7 percent. For more information regarding how MISO establishes requirements please see the 2012 LOLE Study Report.

forecasted to be 75,363 MW. Last year's demand forecast of 75,363 MW is 0.4 percent higher than this year's demand forecast of 75,084 MW.

Demand-Side Management

MISO bases its resource evaluation on the actual market peak. MISO currently separates Demand Response Resources into two categories, Interruptible Load and Direct Control Load Management (DCLM). Interruptible load of 2,593 MW for this assessment is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. DCLM of 305 MW for this assessment is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator.

Generation

The total amount of current generation for winter 2012/2013 is 126,526 MW where the Existing-Certain generation is 103,825 MW, the Existing-Other is 11,652 MW, and the Existing-Inoperable is 1,625 MW

Last year's Existing (Certain, Other, and Inoperable) capacity of 128,519 MW is 1.6 percent higher than MISO's projected Existing capacity of 126,526 MW for the upcoming winter season. This difference is mostly due to exit of Duke Ohio and Kentucky from MISO into PJM effective January 2012. The remaining MW changes were from new generation,[48] retirements and suspensions,[49] and reclassified units.[50]

The three primary fuel sources for MISO are coal, gas and nuclear. Coal units will account for 54.2 percent (62,003 MW), while gas and nuclear units will be 28.5 percent (32,690 MW), and 7.1 percent (8,203 MW), respectively.

MISO has not identified areas of concern regarding the reliability of its fuel sources; however, MISO is currently in the process of identifying areas of concern regarding the reliability of natural gas. In 2012, approximately 33 percent of MISO's gas-fired power plants are dual-fuel capable with ability to switch within zero to six hours. Approximately 20 percent of the total natural gas fleet, MISO has Firm gas supply contracts.

There are 129 MW of Future-Planned resources projected to come online throughout the assessment period. These units (natural gas and wind) are expected to be on line by January 2013.

Between May 2012 and October 2012, MISO has experienced 382 MW of unit retirements. 80 percent of the units retired in June of 2012, while the remaining units are scheduled to retire in October of 2012. During 2012/2013 winter seasons, 314 MW of unit retirements are projected by MISO. The majority will take place in December 2012.

Currently, 10,722 MW of wind resources are registered with MISO; however, MISO applies a 14.7 percent wind capacity credit to MISO wind resources based on their historical performance. The 14.7 percent system wide MISO wind capacity credit is based on determining the Effective Load Carrying Capacity (ELCC) of the intermittent wind resources.[51] Applying the 14.7 percent capacity credit brings the wind capacity down from 10,722 MW to 1,576 MW; however, MISO is not expecting 1,576 MW on peak. Of the 1,576 MW of wind, only 563 MW are registered as designated network resources in March 2012 commercial model, and are expected to serve MISO load during the 2012 winter season. Therefore, of the 10,722 MW of registered wind resources, MISO anticipates 563 MW of wind capacity on peak during the 2012 winter.

Capacity Transactions on Peak

The MISO only reports net power imports to the MISO market or reported interchange transactions into the MISO market. The forecast reflects 2,714 MW of power imports from year-to-year. All these imports are Firm and fully backed by Firm transmission and Firm generation.

[48] New Generation does not necessarily refer to newly built generation. It is simply new from the March 2011 Commercial Model to the March 2012 Commercial Model.
[49] Retirement and suspension information gathered per the Attachment Y process.
[50] MW Change from last year Commercial Model, Unit either designated to BTMG or Psuedo Tied Out of MISO
[51] For more detailed information regarding the wind capacity credit and ELCC study please see the 2012 LOLE study report.

Transmission

At this time MISO does not anticipate any project delays or temporary service outages during the upcoming winter season. There are no concerns in meeting target in-service dates of transmission identified. MISO does not have any transmission constraints that could significantly impact reliability.

Two main projects with in-service date of December 2012 that enhance the reliability of the system during 2012/2013 winter are the breaker replacement project throughout the ITC 345KV and 120 KV system, and addition of a 230/115 kV transformer at Cass Lake station.

Operational Issues

MISO is not anticipating any unusual operating conditions during the 2012/2013 winter.

Vulnerability Issues

New and proposed regulatory compliance obligations will potentially cause the retirement of an estimated 12 GW of coal-fired capacity in MISO, causing a shift in the region's fuel mix. Natural gas-fired plants are expected to replace much of the retired capacity.

Additional Information

MISO's membership has changed since the 2011 winter. Duke Energy Ohio and Duke Energy Kentucky consolidated into the PJM RTO on January 1st 2012, removing approximately 5,700MW of load and generation from MISO's footprint. The Entergy operating companies Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc. intend to join MISO in December 2013. Total Internal Demand and Net Energy Load for Entergy are not included in the above sections as the current Module E Capacity Tracking tool doesn't capture the information. MISO is not including Entergy in the 2012/2013 winter analysis.

MRO-Manitoba Hydro

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**4,407**
Load-Modifying Demand Response	225
Net Internal Demand	**4,182**

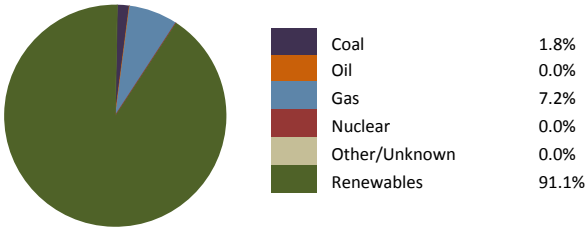
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	4,477
Actual Demand	4,371

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-50
Existing-Certain and Future-Planned Capacity	5,464
Anticipated Resources	**5,414**
Anticipated Reserve Margin (%)	**29.46%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**5,414**
Prospective Reserve Margin (%)	**29.46%**
NERC Reference Margin Level (%)	**12.00%**

Assessment Area Capacity Mix



Assessment Area Highlights

The purpose of this section is to present winter 2012 - 2013 projections for reliability, resources, demand, and transmission infrastructure in the Manitoba Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The Reserve Margins for the Manitoba Assessment Area are based on Anticipated or Prospective resources. The Planning Reserve Margins, 29.5 percent, (Existing-Certain and Net Firm Transactions; Anticipated; Prospective) will remain above Manitoba Hydro's Reference Reserve Margin Level of 12 percent during the 2012 - 2013 winter assessment period.

An additional 200 MW of new hydro capacity will be in-service for the 2012 - 2013 winter season. The Total Internal Peak Demand in Manitoba for the 2012/2013 winter season is forecast to be 4,407 MW in January 2013. Total Internal Demand for the winter peak has decreased from 4,477 MW for the 2011/2012 winter season. The small difference is a result of updating input variables into the Peak Load Model,[52] namely updating weather and economic variables.

Planning Reserve Margins

Manitoba is projecting above adequate Planning Reserve Margins during the 2012/2013 winter season for the existing, anticipated, and prospective reserve margin cases. All reserve margin cases for all winter months are projected to exceed 29 percent.

Manitoba Hydro has planned and maintained its system in accordance with good utility practice such that adequate Planning Reserve Margins shall be maintained throughout the winter season. No unit retirements, extraordinary load growth or additional environmental restrictions are expected. Manitoba Hydro does not anticipate any significant challenges to maintaining the Planning Reserve Margin projections throughout the winter season.

Demand

Last winter's actual peak demand of 4,371 MWs occurred in January 2012 compared to the forecasted peak of 4,477 MW. December 2011 through February 2012 was warmer than normal and the peak demand occurred at warmer temperatures than previous years.

[52] http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/attachment_1.pdf.

This year's Total Internal Demand forecast of 4,407 MW is 1.6 percent lower than last year's Total Internal Demand forecast. The small difference is a result of updating input variables into the Peak Load Model, namely updating weather and economic variables. Economic forecast assumptions come from the 2012 Economic Outlook[53] and the 2012 Energy Price Outlook[54] prepared by Manitoba Hydro's Economic Analysis Department.

Demand-Side Management

Manitoba Hydro is projecting 19 MW of energy efficiency (conservation) to be realized for the 2012/2013 winter peak. There is 225 MW of demand response projected to be available for the 2012/2013 winter peak. Manitoba Hydro deploys Demand Response programs only during system contingencies/emergencies. Interruptible customer load may only be used to reduce peak demand if contingency reserve obligations are in jeopardy of not being met. The Demand Response program used for Ancillary Services (Non Spinning Reserves) in place at Manitoba Hydro is the Curtailable Customer Load Option R[55]. Manitoba Hydro has an agreement with a large industrial customer to carry 50 MW of Non Spinning Reserves in the form of a curtailable customer load.

Generation

5,464 MW of Existing-Certain resources are expected to be available for the winter 2012/2013 peak. Hydro is the primary fuel source in Manitoba. Reservoir levels are sufficient to meet both peak demand and daily energy demand. Manitoba Hydro is not anticipating any issues that could significantly impact reliability of hydro as a fuel source.

For resource adequacy analysis, Manitoba Hydro uses 8 percent of wind generation nameplate for summer capacity and 0 percent of wind generation nameplate for winter capacity. Short-term impacts for changes to capacity include the Wuskwatim Generating Station which is expected to be in-service for the winter season, adding 200 MW of Existing-Certain capacity to Manitoba's generation. Unit outages for the winter season are expected to amount to approximately 179 MW during the winter peak. Potentially 25 MW of capacity will be returned to service after prolonged maintenance. There are no significant short-term impacts expected with this additional capacity which will either marginally supplement Manitoba's real-time exports or suppress real-time imports. Approximately 74 MW of capacity is expected to be unavailable during the winter season due to long-term outages, no significant short-term impacts are expected due to this lost capacity as Manitoba's internal generation plus import capability far exceeds their expected internal demand over the upcoming winter peak load.

Wind resources in Manitoba Hydro include two existing variable capacity resources, St. Leon wind farm, and St. Joseph wind farm, which have about 120.5 MW and 138 MW of nameplate capacity (maximum capacity), respectively. Although Manitoba Hydro has contractual rights to all capacity from these facilities no capacity credit is given to wind resources for winter reliability/capacity purposes.

The expected on-peak capacity for hydro is 5,173 MW for the winter peak. Expected on-peak values for hydro generation are determined using testing and data processing procedures in accordance with the Midwest Reliability Organization (MRO) Generator Testing Guidelines.[56] The expected on-peak capacity that a unit can sustain is computed using the test results.[57]

Capacity Transactions

All of Manitoba Hydro's dependable exports and/or imports are backed by contracts and Firm transmission service. Manitoba Hydro has 550 MW of on-peak capacity exports and 500 MW of on-peak capacity imports in the winter season. Manitoba Hydro's emergency energy imports are characterized under the MISO-Manitoba Hydro Contingency Reserve

[53] http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_4_1.pdf
[54] The Energy Price Outlook is proprietary and not available for public consumption.
[55] Page 4 of http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_10_4.pdf
[56] www.midwestreliability.org/03_reliability/06_gtrtf/Documents/MRO_Generator_Testing_Guidelines.pdf
[57] These values are adjusted for ambient conditions and don't include any capacity utilized for station service. For reservoir hydro units, the values are corrected to the five-year median head for each month, while for run-of-river hydro units, the calculations is the average net integrated hourly capability for all hours of historical operation for each month.

Sharing Group (CRSG) agreement. Only upon significant contingencies involving the loss of generation or transmission facilities do Manitoba Hydro system operators have the ability to request emergency energy imports from MISO under the CRSG. The total reserve carried in the reserve sharing group is 2,000 MW (150 MW for Manitoba Hydro, 1850 MW for MISO). There is no new additional import/export capability planned for the 2012/2013 winter season.

Transmission

Manitoba Hydro does not foresee any significant project delays or temporary service outages of any significant transmission facilities that could impact reliability.

Operations

On an annual basis, Manitoba Hydro performs an operational study to determine the hydro storage reserve requirements necessary to meet demand under the lowest historic flow on record and a high load forecast. There have been no unique operational problems observed.

Manitoba Hydro does not anticipate any unusual operating conditions that could significantly impact reliability for the upcoming winter season.

Vulnerability Assessment

As a predominately hydro region, Manitoba Hydro has an energy criterion which requires adequate energy resources to supply the Firm energy demand in the event that the lowest recorded coincident river flow conditions on the 97 year hydraulic flow record are repeated. In other words, the Manitoba Hydro system is designed and operated to serve all Firm load requirements under the worst inflow conditions on record coincident with high winter load conditions. Drought contingency plans are well established and operational concerns are not a factor.

Manitoba Hydro's system tends to be energy constrained rather than capacity constrained. As a result of the tendency to be energy constrained, there are typically significant amounts of surplus generation capacity available. Therefore it is possible to manage resources around significant long-term generator outages of capacity resources.

The most significant operational concern for this scenario is the need to carry contingency reserves elsewhere when the non-spinning reserves normally available as Demand Response are unresponsive. In addition, when interruptible customer load is unavailable, system operators will have to rely more heavily on emergency energy purchases prior to shedding Firm load under severe system contingencies.

The Raven Lake MR11 Tripping SPS was installed at Raven Lake station in October 2011 with the SPS tripping function disabled and will be in service for the 2012/2013 winter season. The purpose of this SPS is to prevent overloading of the 115 kV line MR11 under certain system contingencies.

Manitoba Hydro does not anticipate any supply or transportation issues for the 2012/2013 winter season. On-site coal supplies are adequate with contracts in place for additional deliveries if required. Alberta natural gas supplies and transportation to Manitoba are plentiful. TransCanada Pipeline has been experiencing significant de-contracting of Firm transport by its customers resulting in additional transport available should Manitoba Hydro need to run its gas-fired generation during the winter season. Gas supply is available either from Alberta or from the East via backhaul arrangements. Manitoba Hydro does not have any Firm arrangements in place for supply or transport at this time.

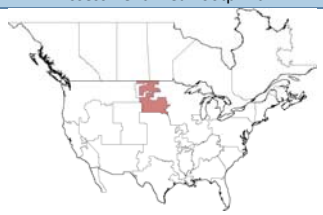
MRO-MAPP

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**5,512**
Load-Modifying Demand Response	375
Net Internal Demand	**5,137**

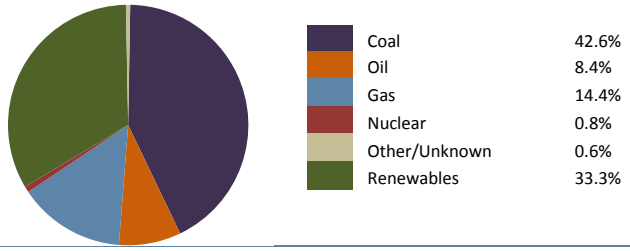
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	5,036
Actual Demand	4,371

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-507
Existing-Certain and Future-Planned Capacity	7,408
Anticipated Resources	**6,901**
Anticipated Reserve Margin (%)	**34.36%**
Existing-Other and Future-Other Capacity	233
Prospective Resources	**7,134**
Prospective Reserve Margin (%)	**38.89%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

MAPP is projecting adequate Planning Reserve Margins during the 2012/2013 winter assessment period. All categories of reserve margin (Existing 33 percent, Anticipated 34 percent, and Prospective 39 percent) exceed the NERC target reference margin of 15 percent for thermal systems and 10 percent for hydro systems. MAPP does not anticipate any scenarios that would lead to a significant detraction from these projections for the upcoming winter season.

Demand

The 2011/2012 MAPP actual winter peak non-coincident demand was 5,217 MW compared to the demand forecast of 5,078 MW in the 2011/2012 MAPP winter reliability assessment which was about 2.7 percent under actual winter peak non- coincident demand. This winter's peak demand forecast is 5,561 MW which is about a 7 percent increase over last winter's actual peak. The MAPP non-coincident internal peak demand forecast was developed by aggregating individual entity peak demands.

Each MAPP LSE uses its own forecasting methodology. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal or 50/50 weather patterns. There were no changes in this year's forecast assumptions in comparison to last year.

Load growth in the MAPP assessment area can be attributed to increasing energy needs of Minnkota Power Cooperative (MPC) end use customers and the addition of new customers in MPC. Additionally Basin Electric Power Cooperative (BEPC) is continuing to experience load growth in western North Dakota due to increased oil activity in excess of normal load growth.

Demand-Side Management

The total amount of Energy Efficiency (Conservation) that is expected to be available on-peak for the 2012/2013 winter season is 29 MW. The total amount of Demand Response that is expected to be available on-peak for the 2012/2013 winter season is 375 MW. The bulk of the demand response in the MAPP Assessment area is located in MPC's service territory and is treated as load-modifying.

A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the assessment period. MAPP entities utilize various measurement and verification programs for demand response, such as those based upon International Performance Measurement and Verification

Protocols (IPMVP).[58] Energy efficiency is verified through several means, such as use of the Minnesota Deemed Savings Database[59] provided by the Minnesota Office of Energy Security.[60]

Generation

The Existing-Certain capacity resources at the time of the assessment period are 7,340 MW. There are 233 MW of Existing-Other and 0 MW of Existing-Inoperable capacity. The primary fuel sources in MAPP are coal (45 percent), hydro (31 percent), natural gas (10 percent), oil (9 percent), and wind (4 percent). MAPP does not have concerns about the reliability of its most dominant fuel sources.

There are 68 MW of Future-Planned resources projected to come online throughout the assessment period. Northwestern Energy is in the process of installing an internal peaking unit of 60 MW in Aberdeen, South Dakota. The unit will be simple cycle gas fired and is expected to be on line by January 2013. Hutchinson Utilities Commission is adding 8 MW of natural gas fired generation.

There have been no significant unit retirements, deferments, derates, or other negative impacts to Existing-Certain capacity in the prior year. Further, there are no significant unit retirements, deferments, derates, or other negative impacts projected to Existing-Certain capacity during the assessment period.

MAPP is not projecting any significant new generation, generator uprates, units taken out of service, units brought back in service, or long-term outages over the assessment period. There has been no change in behind-the-meter generation, or changes in other "non-traditional" resources in the previous year.

Of the Existing-Certain capacity resources, 436 MW of wind generation is expected on-peak, with a nameplate rating of 1,080 MW. To determine wind expected peak, MAPP utilizes a methodology that is based on a median of actual wind output.[61] Additionally, there are 1,980 MW of hydro and 3 MW of biomass Existing-Certain capacity resources in MAPP.

Capacity Transactions

MAPP is projecting total Firm imports of 262 MW. MAPP is projecting total Firm exports of 768 MW. For both imports and exports, Firm contracts exist for both the generation and the transmission service. Firm contracts are at least one year in length, and some extend out twenty years or more. Capacity transactions projected beyond the length of Firm contracts may be based on extensions of those contracts. Transmission providers within MAPP handle Liquidated Damage Contracts (LDC) according to their tariff policies.[62] MAPP is forecasted to meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources.

No emergency imports are required to meet the Reserve Margin target in MAPP. There are no additional import/export capabilities newly available for the 2012/2013 winter season.

Transmission

MAPP has not identified any project delays or temporary service outages of any significant transmission facilities during the 2012/2013 winter season.

The Basin Electric Power Cooperative/Western Area Power Administration/Heartland Consumer Power District Integrated System has energized several new interconnections since the 2012 summer season. A new Wheelock 230/115 kV substation is scheduled to be energized late 2012 on the Williston – Tioga 230 kV line to support load growth in the region. New Southwest Minot and Berthold substations are also scheduled to be added to the Logan – Kenmare – Tioga 115 kV line by

[58] Efficiency Valuation Organization - http://www.evo-world.org/
[59] MN Department of Commerce - http://mn.gov/commerce/energy/topics/conservation/Design-Resources/Deemed-Savings.jsp
[60] MPC staff provides direction and expertise to its member cooperatives for both conservation and energy efficiency improvements. MPC has been and remains active in its load management program involving its member cooperatives.
[61] These values are adjusted for ambient conditions and don't include any capacity utilized for station service. For reservoir hydro units, the values are corrected to the five-year median head for each month, while for run-of-river hydro units, the calculations is the average net integrated hourly capability for all hours of historical operation for each month.
[62] Most MAPP LSEs are within non-retail access jurisdictions and therefore liquidated damages products are not typically used.

the end of 2012. Northwestern Energy is reconductoring the 115 kV line between the Seibrecht Substation and the Redfield Jct. Substation. The estimated completion of the first phase is November 2012. They are replacing 4/0 ACSR with 556 ACSR. The second phase of this project is to reconductor between Redfield Jct. and Huron "A" Tap and is scheduled to start in the spring of 2013.

Operations

No significant operational issues are expected this winter for the MAPP assessment area.

An extended drought could reduce the available cooling water at the Laramie River Station. Although there is the possibility of environmental restrictions affecting reliability in the near future, currently Heartland Consumer Power District (HCPD) believes that there are no regulatory/environmental restrictions that will affect system reliability this winter.

Vulnerability Assessment

A long-term drought in the region that results in significantly reduced hydroelectric production could cause a regional resource inadequacy. Similarly, an extended drought could reduce the available cooling water at the Laramie River Station.

MAPP does perform studies that consider known and anticipated fuel supply or delivery issues in its assessment. Because the MAPP Planning Authority area has a large diversity of fuel supply, inventory management, and delivery methods, MAPP does not have a specific mitigation procedure in place should fuel delivery problems occur. Resource providers do not foresee any significant fuel supply and/or fuel delivery issues for the upcoming 2012/2013 winter season. Any fuel supply issues that may develop will be handled on a case by case basis.

Adequate water is anticipated for normal generation during the winter assessment period. Coal stockpiles are near full and there does not appear to be any supply or transportation issues at this time.

Significant load growth is anticipated in the western North Dakota region due to oil production activity. Temporary operating guides will be developed for critical outages in the area to ensure reliable operation until transmission reinforcements are placed in service.

MRO-SaskPower

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**3,512**
Load-Modifying Demand Response	86
Net Internal Demand	**3,426**

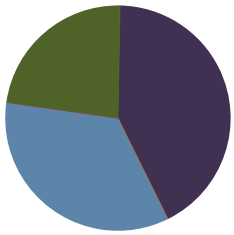
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	3,391
Actual Demand	3,241

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	3,901
Anticipated Resources	**3,901**
Anticipated Reserve Margin (%)	**13.86%**
Existing-Other and Future-Other Capacity	185
Prospective Resources	**4,086**
Prospective Reserve Margin (%)	**19.25%**
NERC Reference Margin Level (%)	**13.00%**

Assessment Area Capacity Mix



Coal	42.4%
Oil	0.0%
Gas	34.6%
Nuclear	0.0%
Other/Unknown	0.0%
Rewables	23.0%

Assessment Area Highlights

Other than seasonal derates, there are no significant capacity changes since the release of the 2012 Summer Seasonal Reliability Assessment . According to the Saskatchewan demand forecast, Total Internal Demand is forecasted to be 3,500 MW for the 2012/2013 winter assessment period. Last year's forecasted peak Total Internal Demand for the 2011/2012 winter assessment period was 3,365 MW. This increase (about 4 percent) is due primarily to increased industrial activity in Saskatchewan. No significant transmission issues are expected to impact reliability during the 2012/2013 winter season.

Planning Reserve Margins

An adequate Planning Reserve Margin is projected for Saskatchewan during the 2012/2013 winter assessment period. Planning Reserve Margin's for all months this winter exceed 13 percent. Saskatchewan's criteria for adding new generation resources are based on Expected Unserved Energy (EUE). The probabilistic EUE value equates to an approximate 11 percent to 13 percent monthly Reference Margin Level. Adequate resources have been planned for Saskatchewan to meet anticipated load for the 2012/2013 winter assessment period.

There are no anticipated challenges that would lead to significant detractions of Planning Reserve Margin projections for Saskatchewan for the 2012/2013 winter season.

Demand

The 2011/2012 winter Total Internal Demand forecast was 3,365 MW. The actual 2011/2012 peak demand was 3,241 MW. The actual peak was lower than forecast due mainly to lower than expected industrial activity and a warmer than expected winter season. According to the Saskatchewan demand forecast, Total Internal Demand is forecasted to be 3,500 MW for the 2012/2013 winter assessment period. The 4 percent increase in the winter Total Internal Demand is due primarily to increased economic growth in Saskatchewan.

Demand-Side Management

Approximately 44 MW of energy efficiency and 86 MW of demand response are expected to be in use during the 2012/2013 winter peak. Demand response resources are treated as demand-side contractually interruptible.[63]

[63] Demand Response is used for reserve purposes in Saskatchewan.

The primary driver for Demand-Side Management (DSM) programs in Saskatchewan is economic incentive (difference in cost between providing the DSM program and the cost of serving the load). Increases in DSM for the 2012/2013 winter season will come from growth of existing programs. No new Demand Response programs are being incorporated for the 2012/2013 winter assessment period in Saskatchewan.

Generation

For Saskatchewan an average of 3,902 MW of existing-certain resources are expected to be available for the 2012/2013 winter assessment period. An average of 186 MW of existing-other resources includes wind derates; hydro derates, and scheduled maintenance.

The primary sources of fuel for Saskatchewan are coal, hydro, and natural gas. Saskatchewan does not anticipate any reliability issues associated with these fuel types. Natural gas resources have Firm on-peak transportation contracts with large natural gas storage facilities located within the province to back the contracts.

There are no Future-Planned resources, anticipated unit retirements, project deferments, or any other impacts that would affect the existing capacity level since the 2012 summer assessment period. Unit derates of less than 45 MWs for conventional units are expected. No generation additions or uprates are expected to occur during the 2012/2013 winter season. There are no additional units that will be taken out of service during the 2012/2013 winter season in Saskatchewan, other than those that are part of the regular maintenance plan. There are also no units that will be brought back into service during the 2012/2013 winter season in Saskatchewan, other than those that are part of the regular maintenance plan.

For Saskatchewan, an average of 39 MW of wind, 850 MW of hydro, and 10 MW of biomass is expected on-peak during the 2012/2013 winter season. Nameplate capacities of wind, hydro, and biomass are 197 MW, 853 MW, and 10 MW respectively. For the 2012/2013 winter season, Saskatchewan plans for 20 percent of wind nameplate capacity to be available to meet on-peak demand. This value was determined using historical data and analyzing the actual amount of wind available during the 4 hours of each daily peak over each month. On-peak expected values for hydro assume nameplate net generation less expected seasonal derates due to water conditions.

On-Peak Capacity Transactions

At this time, there are no Firm imports and/or exports that are backed by contracts for the 2012/2013 winter season involving Saskatchewan. There will be no additions of import/export capabilities that will be newly available for the 2012/2013 winter season.

Transmission

There are no project delays or temporary transmission service outages for transmission facilities in Saskatchewan that are expected to impact reliability during the 2012/2013 winter season. Additionally, there are no specific new projects that have been identified to maintain or enhance reliability during the 2012/2013 winter season.

Operations

SaskPower performs daily assessments as to the adequacy of its generation fleet to meet the expected loads while maintaining its reserves. These assessments will take into account any extreme weather conditions and if warranted, refinements to those assessments will be completed as required.

Saskatchewan has no general operational concerns for the coming 2012/2013 winter season. No unit retirements, project deferments, derates, or other capacity reductions are expected in Saskatchewan for the 2012/2013 winter. When applicable, Saskatchewan plans to mitigate future capacity reductions with new sources of generation and/or Firm imports.

Vulnerability Assessment

Saskatchewan has no resource adequacy or operational concerns for the following conditions: long-term/ extended drought, significant long-term generator outages, unresponsive or unavailable demand response, or significant penetration of variable generation for the 2012/2013 winter season.

With regards to coordination with the fuel supply industry, coal resources have Firm contracts and are mine-to-mouth operations. Coal stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Typically there are 20 days of on-site stockpile for each of the coal facilities which in total represent approximately 47 percent of total provincial installed capacity. Strip coal reserves are also available and only need to be loaded and hauled from the mine. These reserves range from 30 to 65 days depending on the plant.

Natural gas resources have Firm on-peak transportation contracts with large natural gas storage facilities located within the province to back the contracts. Coordination meetings between the electric system and the natural gas transportation system are held to discuss operational and planning issues. These meetings enable both systems to be informed of any issues relating to security of supply for natural gas transportation.

NPCC Summary

The five Northeast Power Coordinating Council, Inc. (NPCC) Reliability Coordinator sub-areas, or subregions, are defined by the following footprints: (1) The Maritimes sub-Area (the New Brunswick System Operator, Nova Scotia Power Inc., the Maritime Electric Company Ltd. and the Northern Maine Independent System Administrator, Inc); (2)New England (ISO New England Inc.); (3) New York (New York ISO); (4) Ontario (Independent Electricity System Operator); and (5) Québec (Hydro-Québec TransÉnergie).

The Planning Reserve Margins for the NPCC Assessment Area are based on Existing Certain and Net Firm Transactions resources. The Anticipated Planning Reserve Margin will remain above the Reference Reserve Margin Level during winter 2012/2013 season. According to the aggregate of NPCC demand forecasts, Total Internal Demand is expected to increase to 112,063 MW from the 2011/2012 winter amount of 111,804 MW. This equates to an annual growth rate of 0.2 percent.

Demand, Capacity & Planning Reserve Margins

A comparison of winter 2012/2013 projections, winter 2011/2012 forecasted and actual demands with the lowest planning reserve margin projections is as follows:

NPCC Sub-Area	2012/2013 Winter Forecasted Peak (MW)	2012/2013 Winter Forecasted Reserve Margin (percent)	2011/2012 Winter Forecasted Reserve Margin (percent)	2011/2012 Winter Forecasted Peak (MW)	2011/2012 Winter Actual Peak (MW)
Maritimes	5,246	30.2%	21%	5552	4,963
New England	22,355	65.3%	45%	22255	19,926*
New York	24,832	34.1%	47%	24533	23,901
Ontario	22,087	39.2%	36%	22311	21,847
Québec	37,543	10.9%	11%	37153	35,481

*Reconstituted peak was 21,354 MW.

The Maritimes, New England, Ontario and Quebec Subregions are projecting reserve margins that are higher than last winter. New York is projecting a lower reserve margin but it is still well in excess of any requirements.

The NPCC real time operating reserve requirements are indicated in the NPCC Directory #5, “Reserve.” Existing-Certain resources expected in the NPCC Assessment Areas for the 2012/2013 winter months are shown below:

Month	Maritimes	New England	New York	Ontario	Québec
December 2012	6,560	34,010	31,877	28,984	39,754
January 2013	6,593	34,323	32,924	30,042	39,606
February 2013	6,599	33,104	32,418	29,058	39,428

Operations

The following are highlights that should be noted with regard to operations within NPCC during the winter 2012/2013 period:

- Two refurbished nuclear generators (1,500 MW) in Ontario are scheduled to return to service before 2012/2013 winter.
- The Beck-Packard 230 kV BP76 New York-Ontario tie is expected to return to service during the 2012/2013 Winter.
- The Point Lepreau nuclear station in the Maritimes is scheduled to return to service prior to the 2012/2013 winter period.
- The Gentilly-2 nuclear station in Québec will be retired for decommissioning at the end of 2012.
- Synchronous Condenser CS23 at Duvernay substation in the Montréal area, which has been out of service since June 2008 due to a transformer fault will be back in service for the 2012/2013 Winter Operating Period. This will enhance transmission capability on the Southern Interface in the load area of the system.
- Hydro-Québec TransÉnergie (HQT) is proposing to install a new generation rejection Type III SPS at Bersimis-1 and 2 Generating Stations. The SPS should be operational in October 2012. The SPS is required because a double-circuit 315-kV transmission line will be unavailable while work is being performed to integrate three wind power plants on the Bersimis sub-system

NPCC-Maritimes

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**5,246**
Load-Modifying Demand Response	170
Net Internal Demand	**5,076**

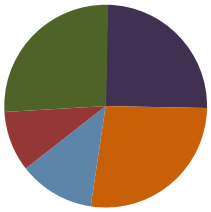
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	5,552
Actual Demand	4,963

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	14
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	6,593
Anticipated Resources	**6,607**
Anticipated Reserve Margin (%)	**13.86%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**6,607**
Prospective Reserve Margin (%)	**30.17%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Coal	25.0%
Oil	27.1%
Gas	12.1%
Nuclear	9.6%
Other/Unknown	0.0%
Renewables	26.2%

Planning Reserve Margins

When allowances for unplanned outages (based on a discreet MW value representing an historical assessment of the total forced outages in MW typically realized at the time of peak for the given operating season) are considered, the Maritimes Area is projecting more than adequate surplus capacity margins above its operating reserve requirements for the winter 2012/2013 assessment period.

The projected reserve margins for the 2012/2013 winter period (for the months of December, January and February) range from 30.2 percent to 38.7 percent, with the minimum reserve margin of 30.2 percent projected for the month of January.[64] When compared to the corresponding projected reserve margins for the 2011/2012 winter period, the monthly reserve margins ranged from a minimum of 20.7 percent in the month of January to 25.7 percent.

Demand

The Maritimes Area 2011/2012 forecasted peak demand of 5,552 MW was projected to occur the week of January 8, 2012. The actual peak for the 2011/2012 winter was 4,963 MW and it occurred on February 13, 2012. The 2011/2012 actual winter peak was 589 MW (10.6 percent) lower than the forecasted peak demand. The difference can be attributed to the shutdown of a large industrial load and milder than expected winter temperatures. The Maritimes Area is forecasting a 5,246 MW peak demand for the 2012/2013 winter reporting period. The difference in the forecasted amounts is due to the loss of industrial load and warmer forecasted temperatures.

Demand-Side Management

In the Maritimes Area there is between 144 MW and 198 MW of interruptible demand available during the assessment period; there is 170 MW forecasted to be available at the time of the Maritimes Area seasonal peak. The interruptible load demand that is used comes from industrial loads that are metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions.

[64] The Reserve Margins for the Maritimes Assessment Area are based in accordance with NPCC Directory #1.

The Maritimes Area is broken up into sub-areas and each sub-area has its own energy efficiency programs. These programs are primarily aimed at the residential consumer to help reduce their heating costs. It is usually geared towards heat as the Maritimes Area is a winter peaking system.[65]

Generation

The Maritimes Area projected Total Internal Capacity is 7,423. The Maritimes Area only considers Existing-Certain resources when doing its seasonal assessment. There is a very diverse fuel supply made up of nuclear (Point Lepreau unit scheduled back in service October 2012), natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind and wood. The primary sources of fuel are hydro, oil, coal, natural gas and nuclear. Wind and biomass nameplate capacity make up only about 12 percent of the existing capacity. The Maritimes Area is a winter peaking system therefore units, which would affect system reliability, are not planned to be taken out of service during this period. During the 2012/2013 winter assessment period no anticipated capacity reductions expected to occur.

The Dalhousie coal fired plant, totaling 299 MW (a 96 MW unit and a 203 MW unit), retired on May 31, 2012. The Point Lepreau nuclear station is scheduled to be back in service October 2012. It has been off-line being refurbished since April 2008.

Wind capacity within the Maritimes Area is expected to be 816 MW with 168 MW expected on peak. Wind projected capacity is de-rated to its demonstrated average output for each summer or winter capability period. In New Brunswick, Prince Edward Island and NMISA, for wind facilities that have been in production over an extended period of time (three years), a de-rated monthly average is calculated using metering data from the previous three years of demonstrated performance over each seasonal assessment period. Nova Scotia has decided not to include any wind facilities towards their installed capacity (100 percent de-rated).

	2011/2012	2012/2013	
Maritimes Sub-Areas	Nameplate Capacity	Nameplate Capacity	On-Peak Capacity
New Brunswick	294	294	85
Prince Edward Island	164	164	71
Nova Scotia	274	316	0
NMISA	42	42	13
TOTALS	774	816	169

For those generators that have not been in service that length of time (three years), the derating of wind capacity in the Maritimes Area is based upon results from the September 21, 2005 NBSO report titled "Maritimes Wind Integration Study."[66] This wind study showed that the effective capacity from wind projects, and their contribution to LOLE was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production. Wind is the only variable resource currently considered in the Maritimes Area resource adequacy assessment.

On-Peak Capacity Transactions

No on-peak capacity transactions have been scheduled at this time. The Maritimes, through existing agreements with neighboring Balancing Authority areas, namely, ISO-NE and TransÉnergie, has established procedures for the acquisition of emergency energy. But the Maritimes Area does not rely on this assistance when doing its winter assessment.

Transmission

There are no project delays or anticipated transmission outages during the winter that would be expected to significantly affect reliability.

[65] For further information on the energy efficiency programs please review the following links: www.maritimeelectric.com , www.nppower.com , www.mainepublicservice.com , www.emec.com , www.nspower.ca/energy_efficiency/programs/

[66] http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf.

Operations

The Maritimes area does not anticipate any significant reliability concerns for the winter period.

The recent retirement of a 299 MW generating station on May 31, 2012 does not have a significant impact on capacity margins primarily because the Point Lepreau nuclear station is scheduled to return to service prior to the 2012/2013 winter assessment period.

The amount of wind generation presently operating does not require any special operational changes.

The only demand response considered in the resource adequacy assessments for the Maritimes Area is interruptible load. The Maritimes Area uses a 20 percent reserve criterion for planning purposes, equal to 20 percent x (Forecast Peak Load MW – Interruptible Load MW).

Vulnerability Assessment

The Area is forecasting normal hydro conditions for the 2012/2013 winter assessment period. Hydro resources are run of the river facilities with limited reservoir storage facilities. These facilities are primarily utilized as peaking units or providing operating reserve.

Load Management is not included in the resource adequacy assessment for the Maritimes Area. The interruptible load demand that is used is from industrial loads that are metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions.

The amount of wind generation presently operating does not require any special operational changes. If there were a significant increase of wind the New Brunswick System Operator as Reliability Coordinator for the Maritimes Area has the authority to curtail the variable generator as required.

The Maritimes Area closely monitors air emissions and other environmental discharges to ensure compliance with standards and limits set forth by Canadian Federal and Provincial environmental regulations. For the 2012/2013 Winter Operating Period, there may be occasions when some units are required to be derated in order to meet these regulations. However, these occasions are expected to be infrequent, of short duration and are not included in the winter assessment.

It is the responsibility of the generator owners to ensure that fuel supplies are adequate. The Maritimes Area does not consider potential fuel-supply interruptions in the regional assessment. The fuel supply in the Maritimes Area is very diverse and it includes nuclear (scheduled back in-service October 2012), natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind and wood. As such the assessment area does not expect to experience any reliability issues resulting from fuel supply issues.

NPCC-New England

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**22,355**
Load-Modifying Demand Response	963
Net Internal Demand	**21,392**

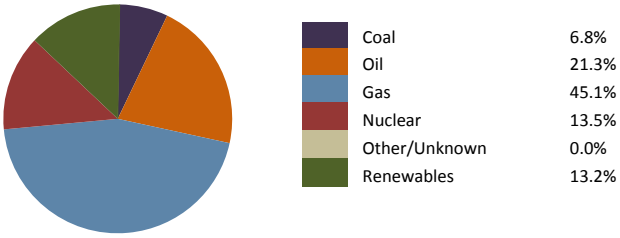
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	22,255
Actual Demand	19,926

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	957
Net Capacity Transactions (Firm and Expected)	475
Existing-Certain and Future-Planned Capacity	34,450
Anticipated Resources	**35,882**
Anticipated Reserve Margin (%)	**67.74%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**35,882**
Prospective Reserve Margin (%)	**67.74%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

ISO New England is projecting adequate Planning Reserve Margins during the 2012/2013 winter season. During the peak demand period in January the Planning Reserve Margin based on Existing-Certain capacity and Net Firm Transactions is 67.1 percent, and both the Anticipated and Prospective Reserve Margins are 67.7percent.

for the purposes of this report, the reference margin level is considered to be 15 percent, which is the target reserve margin assigned by NERC for predominantly thermal systems.[67]

ISO New England has adequate capacity consisting of Existing-Certain generation (34,323 MW), Future-Planned generation (127 MW), demand resources (1,920 MW) and net imports (475 MW) to meet the forecasted Total Internal Demand of 22,355 MW during the winter season. The lowest Anticipated Capacity Resources Reserve Margin of 13,400 MW (65.9 percent) occurs in the month of February.[68]

The amount of capacity that is procured annually through FCM is the amount required to serve the summer peak demand and operating reserves. Therefore, since New England is a summer peaking system with winter peaks historically about seventy five percent of the summer peaks, there will be enough capacity available to serve the lower winter peak loads and operating reserves.

ISO-NE projects available capacity for each week of the year within its Annual Maintenance Schedule (AMS).[69] The AMS's Operable Capacity Analysis takes into consideration the capacity purchased through the FCM, planned generator outages, potential for unplanned outages and generation at risk. "Generation at Risk due to Gas Supply" accounts apply for gas fired capacity expected to be at risk due to potential gas supply issues during cold weather conditions or pipeline maintenance outages. After taking into account the At-Risk generation due to Gas Supply, ISO-NE is still forecasting a sufficient winter capacity margin.

[67] New England does not have a fixed capacity or reserve margin requirement, rather it projects its capacity needs to meet the NPCC once in ten-year loss of load expectation (LOLE) resource planning reliability criterion. The capacity needs can vary from year to year depending on system conditions. Therefore,

[68] ISO New England ensures that it has enough electrical capacity to meet overall system needs through its Forward Capacity Market (FCM). The FCM purchases the amount of capacity required to satisfy the NPCC once in ten-year loss of load expectation resource planning reliability criterion through annual auctions three years in advance of the year of interest. After this primary auction, there are Annual Reconfiguration Auctions prior to the commencement year. These auctions are held to re-adjust installed capacity purchases and to ensure that adequate capacity will be purchased to meet system needs.

[69] The current copy of the Annual Maintenance Schedule is located on the ISO's web site at: http://www.iso-ne.com/genrtion_resrcs/ann_mnt_sched/index.html .

Demand

The 2011/2012 winter peak demand forecast was 22,255 MW. This was 901 MW (4.2 percent) higher than ISO-NE's reconstituted 2011/2012 winter actual peak demand of 21,354 MW, which occurred on January 4. The metered peak demand of 19,926 MW reflects reductions of 1,428 MW due to passive demand resources (energy efficiency). The primary reason for the lower than forecast peak demand was that the weather at the time of the actual peak was 23.7°F, while the 50/50 winter peak forecast is predicated on a temperature of 7.0°F.

The 2012/2013 winter peak demand forecast of 22,355 MW is 100 MW (0.4 percent) higher than the 2011/2012 winter peak demand forecast of 22,255 MW.

As noted by the minor change in the peak demand forecast between last winter and this upcoming winter, the key factors behind this low level of demand growth are the lingering effects of the economic recession.

Demand-Side Management

ISO-NE has 963 MW of passive demand resources that are forecast to be in-service during the 2012/2013 winter peak. Passive demand resources are non-dispatchable load reductions, typically consisting of energy efficiency measures or distributed generation that regularly operates to meet end use customer needs.[70] A total of 957 MW of active demand resources are expected to be available on peak. These demand resources are activated in real time during actual or anticipated capacity/operating reserve deficiencies.

Both passive and active demand resources are treated as capacity in ISO-NE's FCM. The 963 MW of passive demand resources CSOs are treated as demand reducers in this report resulting in a reduced Net Internal Demand. The 957 MW of active demand resources consist of Real-Time Demand Response and Real-Time Emergency Generation and are treated as dispatchable capacity, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 - Action During a Capacity Deficiency (OP 4).[71,72]

Generation

ISO-NE's Existing-Certain generating capacity during the month of January amounts to 34,323 MW based on Winter Seasonal Claimed Capability ratings. Natural gas-fired generation represents the largest component of ISO-NE's total installed capacity at 45.3 percent (15,599 MW), followed by oil-fired generation at 21.4percent (7,358 MW), nuclear generation at 13.6 percent (4,674 MW), and coal at 6.9 percent (2,367 MW). Hydroelectric capacity and pumped-storage capacity make up 4.7percent and 4.9 of the total, respectively. The remaining 3.2percent of capacity consists of renewable resources such as wind or biomass facilities.

It is expected that approximately 74 MW of wind capacity (228 MW nameplate), a 28 MW landfill gas facility and a 25 MW uprate to a wood-burning power plant will be in service before or during the 2012/2013 winter.

The current scheduled generator outages for the ISO-NE winter capacity weekly peak period total 439 MW in December, 126 MW in January and 1,345 MW in February, most of which are for annual generator inspections and could possibly be rescheduled to address reliability concerns.

Within the Existing-Certain category, approximately 188 MW of capacity is wind generation that is expected to be available at the time of peak demand. This reflects a 378 MW derate on-peak, from the total nameplate capability of 566 MW. Solar generation, though not considered impactive during winter evening peak periods, makes up 2 MW of on-peak capacity, derated from its nameplate capacity of 18 MW. Existing-Certain capacity also includes 1,622 MW of hydro-electric

[70] Passive Resources are defined as either On-Peak or Seasonal Peak Resources, the main difference being their performance hours. On-Peak Demand Resources provide their load reduction during non-holiday weekdays in December and January during the on-peak hours of 5:00 to 7:00 p.m. Seasonal Peak Demand Resources must reduce load during non-holiday weekdays when the Real-Time hourly load is equal to or greater than 90% of the most recent 50/50 System Peak Load Forecast for the applicable summer or winter season.

[71] Operating Procedure No. 4 is located on the ISO's web site at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

[72] These active demand response resources can be used to help mitigate an actual or anticipated capacity deficiency. OP 4 Action 2 is the dispatch of Real-Time Demand Response Resources, which is implemented in order to maintain the full NPCC operating reserve requirements. Action 6, which is the dispatch of Real-Time Emergency Generation Resources, is implemented to maintain NPCC 10-minute operating reserve.

resources. This reflects a 421 MW derate on-peak, from the total nameplate capability of 2,043 MW. Biomass capacity in the Existing-Certain category totals 945 MW.

The method for determining the expected on-peak capacity for wind, solar, hydro, and biomass facilities depends on whether the resource is classified as intermittent or non-intermittent. Generally, run-of-river hydroelectric units, many of the biomass plants and all of the wind and solar resources are categorized within the intermittent category. The winter capability of intermittent units is equal to the median of net output during the winter reliability hours each day of the previous winter (October through May), as well as any winter hour with a shortage event.[73]

On-Peak Capacity Transactions

The forecast for 2012/2013 winter on-peak Firm capacity imports is 575 MW. These Firm capacity imports, which include 253 MW from Hydro-Québec and 322 MW from New York, have been contracted for delivery within the 2012/2013 FCM Capability Period.[74,75] A Firm capacity export of 100 MW is anticipated to be delivered via the Cross-Sound Cable (CSC) to New York (Long Island).

Transmission

Currently there are three significant transmission facilities scheduled for maintenance during the winter capacity period. Two of the outages impact post contingency operating requirements for power plants and the remaining transmission facility effects power transfers into Connecticut and between New York and New England. None of these outages are anticipated to impose noteworthy reductions to generator facilities or transfer limits. If unfavorable conditions develop, ISO-NE will coordinate the repositioning of outages as needed.

Though ISO-NE currently has numerous transmission projects underway, none are required to be completed before or during the winter assessment period to either maintain or enhance system reliability.

Operations

There are no significant environmental restrictions that would adversely impact system reliability or require special operating studies during the winter.

ISO-NE does expect the potential for various amounts of single fuel, gas-only power plants to be temporarily unavailable during extreme winter weather conditions or during force majeure conditions on the regional gas grid, and plans to mitigate these scenarios with supplemental commitment. ISO-NE continues to integrate new power supply sources, including new variable resources, into the electrical network. To facilitate system operation with potentially large amounts of wind power, SO-NE Operating Procedure No. 14 Appendix F - Wind Plant Operators Guide (OP 14F),[76] was developed and implemented.[77]

ISO-NE does not have any scheduled unit retirements, communicated project deferments or permanent derates scheduled for the winter 2012/2013 assessment period. New England does anticipate that, in the event of a full dispatch of demand resources during the 2012/2013 winter season, the response rate will be in the range of 85 percent of the full capacity obligation (CSO). This estimate is based on the December 2011 audits of dispatchable Demand Resources which demonstrated an aggregated performance of 84.9 percent of the CSO in place at that time. Those audits were conducted in late afternoons during the typical winter peak load ramp period. Performance could be lower depending on the time of the actual dispatch, as was experienced during the December 19, 2011 dispatch of Real Time Demand Resources. This dispatch was early on a Monday morning and there was essentially no prior indication that a dispatch would be necessary. During

[73] These are events under which ISO-NE operations experience either an operating reserve or capacity deficiency.
[74] The 2012/2013 FCM Capability Period is from June 1, 2012 to May 31, 2013.
[75] Firm Capacity Import contracts rely on external resources to satisfy their FCM Capacity Supply Obligation (CSO), which in turn, contributes to meeting the region's overall Installed Capacity Requirement (ICR).
[76] The ISO Operating Procedure OP 14, Appendix F is located here at: http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14f_rto_final.pdf.
[77] Under the FCM rules, the deliverability of external capacity imports must meet the same deliverability requirements as those of internal generators. The market participant is free to choose the type of transmission service it wishes to use for the delivery of energy associated with these Capacity Imports, but the market participant also bears the associated risks of FCM non-deliverability penalties if it chooses non-Firm transmission.

the period of 100 percent CSO dispatch on 12/19/2011, the aggregate performance was 75.4 percent of CSO. It should also be noted that there has been variation in winter Demand Resource performance between dispatch zones, though there is insufficient data at this time to discern any predictive patterns.

Vulnerability Assessment

Though during the summer capacity period the region had received less rainfall than normal, but New England has not been undergoing a drought and drought conditions are not forecasted for the near future. New England will put into service one new SPS during this assessment period. The SPS is identified as the "Rumford Area Temporary SPS." This temporary SPS is required for a long duration construction outage in western Maine that will take approximately 18 months to complete. Following completion of the construction the SPS will then be permanently retired. The SPS function is to transfer trip a generator following the occurrence of a 115 kV contingency in western Maine. The SPS has completed all of the required New England and NPCC planning requirements for installation as a new SPS. It has been classified as a NPCC Type III SPS, which means that its failure to operate would only affect a local area.

ISO-NE has not identified areas of major concern regarding the reliability of its fuel sources, other than natural gas.[78] As previously noted, most of New England's gas-fired power plants are not dual-fuel capable, and most do not have Firm gas supply or transportation contracts. On days of extreme winter temperatures, single-fuel, natural gas-fired capacity is at risk of being unavailable due to fuel constraints. During the winter period in New England, the regional pipelines run full with gas targeted for use by the regional local distribution companies.[79] Therefore, on an extreme (weather) winter peak day, various amounts of single fuel, gas-only capacity are likely to be fuel constrained. This would result in ISO-NE committing oil and coal units that require lengthy notification timelines to supplement the known loss of gas-fired capacity under these types of winter weather scenarios, or during force majeure declarations on the regional gas grid. This creates operational challenges for near-term planning and real-time operations.

In addition to discussing the winter outlook with regional stakeholders, ISO-NE staff has also attended several regional fuel supply conferences and seminars. Access to and delivery of natural gas to the regional power generation sector continues to be a concern within New England during the winter months. ISO-NE routinely gauges the impacts that fuel supply disruptions could have upon system or subregional reliability. ISO-NE continuously monitors the regional natural gas pipeline systems, via their Electronic Bulletin Board (EBB) postings. This ensures that emerging gas supply or delivery issues can be incorporated into and mitigated within the daily or day-ahead operating plans. Should natural gas issues arise, ISO-NE has predefined communication protocols in place with the Gas Control Centers of the regional pipelines and local distribution companies, in order to quickly understand the emerging situation and subsequently implement mitigation measures. ISO-NE has two procedures that can also be invoked to mitigate regional fuel supply emergencies affecting the power generation sector:

- ISO-NE's Operating Procedure No. 21 - Action During an Energy Emergency (OP21) is designed to help mitigate the impacts on bulk power system reliability resulting from the loss of operable capacity due to regional fuel supply deficiencies that can occur anytime during the year.[80] Fuel supply deficiencies are the temporary or prolonged disruption to regional fuel supply chains for coal, natural gas, LNG, and heavy and light fuel oil.
- ISO-NE's Market Rule No. 1 – Appendix H – Operations During Cold Weather Conditions is a procedure that is designed to help mitigate the impacts on bulk power system reliability resulting from the loss of operable capacity due to the combined effects from extreme cold winter weather or constraints with regional natural gas/LNG supplies or deliveries.[81]

[78] As of late October 2012, regional inventories of distillate fuel oils (i.e. jet fuel, kerosene, diesel and No. 2 fuel oil) are considerably down from their 5-year historical averages. With the restarting of several east coast refineries, this situation is expected to improve prior to winter.
[79] Local Distribution Company is a retail gas distribution company that delivers natural gas to end users.
[80] Operating Procedure No. 21 is located on the ISO's web site at: http://www.iso-ne.com/rules_proceds/operating/isone/op21/index.html.
[81] Appendix H of Market Rule No. 1 is located at: http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-h.pdf.

NPCC-New York

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**24,832**
Load-Modifying Demand Response	0
Net Internal Demand	**24,832**

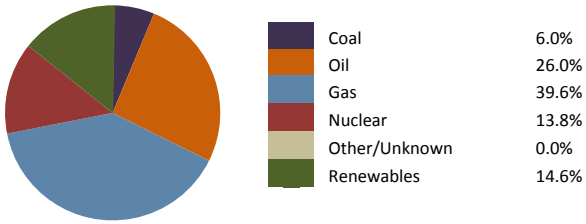
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	24,533
Actual Demand	23,901

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	1,424
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	32,418
Anticipated Resources	**33,841**
Anticipated Reserve Margin (%)	**36.28%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**33,841**
Prospective Reserve Margin (%)	**36.28%**
NERC Reference Margin Level (%)	**16.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

With the minimum Existing-Certain capacity of 31,877 MW and the expected peak of 24,832 MW, there is a wintertime reserve margin of at least 34.1 percent. This exceeds the 16.0 percent annual reserve margin set by the New York State Reliability Council (NYSRC).

The NYSRC has determined that an Installed Reserve Margin (IRM)[82] of 16.0 percent in excess of the NYISO Balancing Authority summer peak demand forecast for the Capability Year 2012/2013 is required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC resource adequacy criterion. There are no foreseen issues or circumstances that could lead to detractions from seasonal projections.

Demand

The 2011/2012 actual peak demand occurred on January 3, 2012 and was 23,901 MW, 632 MW less than the forecast peak demand of 24,533 MW. The weather-normalized peak was 24,630 MW, 97 MW greater than the forecast peak. The primary drivers to the NYISO's peak load forecast are economic growth, energy efficiency impacts, weather trends, and geographic or structural economic changes in an area. There have been no significant changes in any of these drivers in 2012 compared to 2011.

The 2012/2013 winter peak demand forecast of 24,832 MW is 299 MW and 1.2 percent more than the 2011/2012 winter peak demand forecast of 24,533 MW.

Demand Side Management

Estimated energy efficiency impacts during the winter peak are 296 MW. Estimated enrollment of SCR resources for the winter capability period is 1,424 MW. Full deployment of the estimated resources may reduce the winter peak demand of 24,832 MW by up to 5.7 percent. The NYISO offers two demand response programs that support reliability: the Emergency Demand Response Program (EDRP)[83] and the Installed Capacity-Special Case Resource Program (ICAP/SCR).

[82] NYSRC Report titled, "New York Control Area Installed Capacity Requirements for the Period May 2012 - April 2013" (December 2, 2011).
[83] Terms in upper case not defined herein have the meaning ascribed to them in the NYISO's Market Administration and Control Area Services Tariff.

Generation

For the 2012/2013 winter season the NYISO expects 42,201 MW of installed capacity with 31,877 MW of that classified as Existing Certain. Traditionally, New York generation mix has been dependent on fossil fuels for the largest portion of the installed capacity.

A new 216 MW nameplate wind facility, Marble River Wind Farm, is expected to come into service before the winter season. Since May 2012 several units have been retired. They are: Astoria GT 10 (May, 24.2 MW), Glenwood Units 4 & 5 (July, 111 & 105.5 MW), Far Rockaway Unit 4 (July, 106.2 MW) and Astoria GT 11 (July, 26.5 MW). All values are winter capacity ratings.

Since the 2012 summer season the Bayonne Energy Center, a 500 MW nameplate facility has come online while Dunkirk units 3 and 4 with nameplate capacity totaling 435 MW have retired. [5.5]The owner of the coal fired Cayuga units 1 and 2 has given notice of intent to mothball the units in January 2013. They are located in the Finger Lakes region of New York and total 306 MW of winter capacity. [5.6]No short term impacts due to capacity changes are expected in New York.

Installed capacities total: 1,579 MW for wind, 32 MW for solar, 4,685 MW for large hydro, 1,005 MW for run-of-river hydro, 92.9 MW for methane gas and 295.4 for refuse and wood. For the 2012/2013 winter season these capacities are de-rated 70 percent for wind to 473.7 MW, 84 percent for solar to 5 MW, 2 percent for large hydro to 4591.3 MW, 45 percent for run-of-river hydro to 552.8 MW, 16.6 percent for methane gas to 77.5 MW and 8.05 percent for refuse and wood to 271.6 MW.

On-Peak Capacity Transactions

The NYISO projects net imports into the New York Balancing Authority area of 1,100 MW during winter 2012/2013. Capacity purchases in New York are not required to have accompanying Firm transmission reservations, but adequate transmission rights must be available to assure delivery to New York when scheduled.

Transmission

The Moses-Massena MMS2 230 kV line will be out of service for the 2012/2013 winter due to a breaker failure at the Massena switchyard. Due to a transformer failure, the Neptune DC cable will operate at half capacity for the winter season. The Beck-Packard BP76 230 kV line is expected to return to service by January, 2013. There are no foreseen reliability issues associated with these outages.

Operations

The NYISO routinely conducts a winter operating study for the November 1 through April 30 winter capability period. There were no unique operational problems observed from these studies. NYISO has incorporated variable resources into the dispatch software, along with Limited Energy Storage Resources, (flywheel and batteries). These resources are integrated such that no unique operational procedures are required.

The use of demand resources are fully integrated into the policies and procedures of the NYISO. The program design promotes participation and the NYISO expectation is for full participation. Further control actions are outlined in NYISO policies and procedures. There is no limitation as to the number of times a resource can be called upon to provide response.

Vulnerability Assessment

For the 2012/2013 winter season there are no specific operational concerns for extended drought conditions, long-term generator outages, unavailable demand response, increases in variable generation or environmental impacts.

Recent capacity additions or enhancements use natural gas as the primary fuel. While some existing generators in southeastern New York have “dual-fuel” capability, use of residual or distillate oil as an alternate may be limited by environmental regulations. Adequate supplies of all fuel types are expected to be available for the winter period.

NYISO has adopted the New York State Gas-Electric Coordination Protocol as Appendix BB[84] to its Open Access Transmission Tariff (OATT). This Coordination Protocol applies to circumstances in which the NYISO has determined (for the bulk power system) or a Transmission Owner has determined (for the local power system) that the loss of a Generator due to a Gas System Event would likely lead to the loss of Firm electric load. This Coordination Protocol also applies to communications, following the declaration of an Operational Flow Order or an Emergency Energy Alert.

[4] New York State Gas-Electric Coordination Protocol, Attachment BB to the NYISO Open Access Tariff (OATT), June 30, 2010.

NPCC-Ontario

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**22,087**
Load-Modifying Demand Response	0
Net Internal Demand	**22,087**

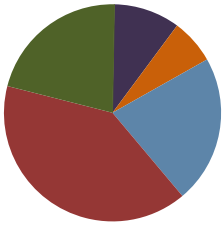
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	22,311
Actual Demand	21,847

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	1,315
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	31,404
Anticipated Resources	**32,719**
Anticipated Reserve Margin (%)	**48.14%**
Existing-Other and Future-Other Capacity	630
Prospective Resources	**33,349**
Prospective Reserve Margin (%)	**50.99%**
NERC Reference Margin Level (%)	**20.40%**

Assessment Area Capacity Mix



Coal	9.9%
Oil	6.7%
Gas	22.1%
Nuclear	40.1%
Other/Unknown	0.0%
Renewables	21.3%

Planning Reserve Margins

Ontario is projecting an adequate Planning Reserve Margin during the 2012/2013 winter. All Planning Reserve Margins (Existing-Certain and Net-Firm Transactions, Anticipated, and Prospective Planning Reserve Margins) vary between 39.2 percent and 51 percent all well above target levels over this period for normal weather conditions. The reserve margin target determined on the basis of the IESO's requirements for Ontario's self-sufficiency is 19.7 percent.

Before the winter of 2012/2013, it is anticipated that there will be more than 1,700 MW of capacity added to the grid, comprising two refurbished nuclear units with a capacity of 1,500 MW returning to service, and more than 200 MW of new grid-connected renewable generation. Generation projects providing additional capacity are expected to be online before the winter 2012/2013 season. Though some delays are possible, Ontario meets the reserve margins target, regardless, with the existing generation capacity.

The IESO addresses winter extreme weather conditions by conducting planning studies using the most severe weather experienced over the last 31 years. Adequacy assessments show that Ontario will have sufficient reserves over the entire winter period.

Demand

The peak demand forecast for the last winter was 22,311 MW under Normal weather and 23,582 MW under extreme weather. The actual (not weather-corrected) peak demand was 21,847 MW. Actual peak demand was slightly lower than the normal weather forecast peak, with actual weather conditions fairly close to normal weather scenario. There was no demand response at the time of the system peak so weather corrected peak demand was only 0.3 per cent different from the forecasted peak.

This winter's peak demand forecast is 22,087 MW which is lower than the peak demand forecast for the winter of 2011/2012. Peak demand is expected to be lower due to four main factors. The economy remains stagnant with little growth in the industrial sector. Residential and commercial load would increase due to the significant level of construction activity. However, that underlying growth will be more than offset by the increase in embedded generation, conservation and customers subject to time-of-use rates.

Demand-Side Management

There are a number of conservation initiatives developed by distributors and the Ontario Power Authority, which are decremented from demand. However, none of these are included as demand response programs.

The IESO has just over 1,850 MW of demand response capacity of which roughly 1,315 MW is deemed to be reliably available at the time of system peak. All of the demand response programs within the IESO's service area are market-driven programs and are dispatched based on market conditions. There are price and demand triggers that both need to be met in order to deploy these resources. These triggers are calculated to meet a certain number of activations per month.

The Dispatchable Loads bid into the market and are dispatched off like any resource. This program has a total capacity of roughly 900 MW. The DR3 program contracts loads that are dispatched off the system based on the supply cushion – the difference between demand and supply. This program has a capacity of 525 MW. Four other programs provide an additional 425 MW of capacity.

Generation

The amount of Existing Certain resources is between 28,984 MW and 30,042 MW over the three months, December 2012 to February 2013. Existing-Other ranges from 480 to 680 MW and Existing Inoperable totals 27.5 MW. The primary fuel of existing resources by installed capacity is nuclear (34 percent), followed by gas/oil (28 percent) and hydroelectric (23 percent). Two refurbished nuclear units (1,500 MW) and two new wind farms (214 MW) are expected to be added prior to the winter season. Atikokan coal unit (211 MW) biomass fuel conversion is underway.

Two refurbished nuclear units will return to service and 214 MW of wind generation will be added before winter. A coal unit will go out of service and biomass fueled Thunder Bay Condensing Turbine (40 MW) is expected to be added during winter. Since the winter of 2011/2012 there has been 300 MW of new embedded generation contracted to begin commercial operation.

For wind, 586 MW is expected at time of winter peak out of a maximum capacity of 1,725 MW. There is no grid-connected solar in Ontario at this time. For hydro, 6,012 MW out of a maximum of 7,947 MW is expected on-peak. For biomass, 44 MW out of 122 MW installed capacity is expected at the time of the winter peak.

Capacity Transactions

In its determination of resource adequacy, the IESO plans for Ontario to meet NPCC regional criteria without reliance on external resources. There are no Firm imports or exports identified for the winter period.

For use during daily operation, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC and MRO include contractual provisions for emergency imports directly by the IESO. IESO also participates in the NPCC Simultaneous Activation of Reserve program which includes PJM, NYISO, ISO-NE and New Brunswick.

Transmission

Planned outages may result in some transfer capability reductions but they are not expected to have any impact on the load supply. The completion date for transmission reinforcements from the Niagara region into the Hamilton-Burlington area continues to be delayed. Completion of this project will increase the transfer capability between the Niagara region to the rest of the Ontario system. Under the conditions expected for this winter, studies show that the system is adequate to meet expected demands without this reinforcement.

Operations

With the addition of nuclear and variable baseload generation to the grid combined with anticipated low off-peak electricity demands, Ontario will likely continue to experience SBG (Surplus Baseload Generation) conditions.

A lack of direct control over a number of factors that contribute to SBG, such as temperature, other weather parameters, consumption, and lack of generation and load response to market prices, poses challenges in handling SBG situations. These events will need to be managed in the short term until baseload generation begins to decline when nuclear refurbishment programs get underway later in the decade.

With the forecast increase in SBG, an increase in out-of-market control actions is foreseen such as minimum hydro dispatch and nuclear maneuvers, to be required in order to manage the surplus, extending beyond the typical market actions which

include exports. With wind and solar becoming more prominent resources on the electricity system, the need for maximum flexibility from all resources has become integral for the reliable and efficient operation of the grid. When variable generation becomes dispatchable, additional flexibility will be available to diminish the frequency of out-of-market control actions for SBG.

Vulnerability Assessment

The hydroelectric production was low from May to July 2012. The hydroelectric forecast was reduced for the fall months. However, it is expected that the production may bounce back to median levels for the winter months. Ontario generates its forecasts using median conditions for hydroelectric generation and does not expect any impacts from drought for winter 2012/2013.

The Atikokan coal unit will be on a long–term outage during winter and beyond for conversion to biomass. The IESO is working with Hydro One and OPG to accommodate the Atikokan coal shutdown and conversion project. Work includes completion of planned maintenance on other critical equipment to support the outage, and ensuring plans to manage high-voltage situations are sufficient to cover the duration of the Atikokan outage.

The IESO includes a quantity of demand response termed “Reliably Available Capacity” in its reliability analysis. This does not represent the total registered capacity of demand response programs. For market-based programs, the IESO utilizes historical information to ascertain the amount of demand response capacity that is typically bid into the market at the time of the weekly peak demand. For programs that have contracts, the IESO uses both historical information and contract information in order to determine the quantity of Reliably Available Capacity.

There are restrictions on how many times Demand Response 3 can be deployed. However there are price and demand triggers that both need to be met in order to deploy these resources. These triggers are calculated to meet a certain number of activations per month.

About 3,200 MW of coal generation has been shut down since 2010. Replacement capacity has come from new gas generation as well as from renewable generation. The existing coal fleet, though running at vastly reduced levels from previous years, provides the IESO with desirable flexibility, such as quick ramping and operating reserve, under all market conditions. As Ontario’s coal-fired generation is shut down over the next two years, its associated flexibility will be lost. Therefore, future capacity additions should also possess this flexibility to help facilitate the management of maintenance outages, provide effective ramp capability, supply operating reserve and even provide regulation when necessary.

Regarding gas-electric interdependency, there are communication protocols in effect between the IESO and gas pipeline operators to manage and share information under tight supply conditions in either sector (gas or electricity).

NPCC-Québec

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**37,543**
Load-Modifying Demand Response	1,830
Net Internal Demand	**35,713**

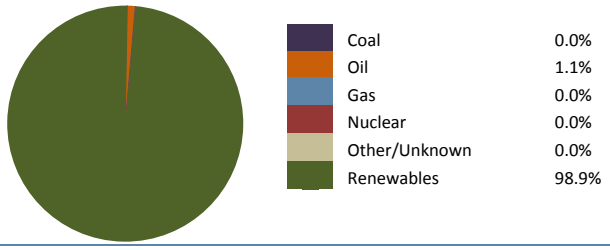
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	37,153
Actual Demand	35,481

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	1,830
Net Capacity Transactions (Firm and Expected)	183
Existing-Certain and Future-Planned Capacity	39,606
Anticipated Resources	**41,619**
Anticipated Reserve Margin (%)	**16.54%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**41,619**
Prospective Reserve Margin (%)	**16.54%**
NERC Reference Margin Level (%)	**9.60%**

Assessment Area Capacity Mix



Planning Reserve Margins

The Québec Assessment Area is projecting adequate Planning Reserve Margins for the 2012/2013 winter peak period, with an Anticipated Reserve Margin equal to 10.9 percent. This Planned Reserve Margin is above the Area Reference Reserve Margin level of 9.6 percent and shows that the Québec Area has sufficient resources to meet its winter peak load forecast. The Québec capacity is predominately hydro (93 percent), so the Reference Reserve Margin level is lower than for systems where the generation makeup is different.[85]

The Planning Reserve Margins projected throughout the 2012/2013 winter season result mostly from the commissioning of additional resources such as La Sarcelle hydro Generating Station (100 MW) along with wind and biomass resources. In fact, more than 760 MW of additional wind power (with an estimated 30 percent capacity value at peak) and about 110 MW of additional biomass will be in service for the 2012/2013 winter peak period. Moreover, additional capacity (150 MW) in the interruptible load program and an additional capacity contribution from existing Hydro-Québec Production (HQP) wind farms (32 MW) contribute to this adequate level of projected Reserve Margins.

Demand

The Hydro-Québec System is winter peaking because a large amount of space heating load is present during Winter Operating Periods. The all-time internal peak hourly demand is 37,717 MW which occurred on January 24, 2011. The internal demand forecast for the 2012/2013 winter peak period is 37,543 MW forecasted for January 2013. This forecast is 390 MW higher than the 2011/2012 winter forecast of 37,153 MW (+1.05 percent). The difference reflects slightly growing demand in all sectors, particularly the industrial sector.

The actual peak demand which occurred on January 16, 2012 was 35,481 MW. The difference between the actual peak demand and the forecasted demand is explained mainly by weather conditions. Winter 2011/2012 was remarkably warmer than the average. In Montréal (the main load area) average temperatures were 3.4°C (6.1°F) higher than normal temperatures. This was the warmest winter since 2001/2002.

[85] The Reference Reserve Margin Level is drawn from the most recent Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on November 29, 2011.

Demand-Side Management

Demand Response (DR) programs in the Québec Area specifically designed for peak-load reduction during winter operating periods and are considered as interruptible demand programs (for large industrial customers). DR totals 1,580 MW for the 2012/2013 winter season. In this assessment, DR resources are treated as supply-side resources. These resources are usually used in situations where load is expected to reach high levels or when resources are not expected to be sufficient to meet load at peak periods. Moreover, total Energy Efficiency/Conservation (Demand Side Management) is included in the forecasted load and accounts for 1,780 MW for the 2012/2013 winter peak period.

Generation

Resources being considered in this assessment for the winter 2012/2013 period are shown below:

- Existing-Certain: 39,606 MW
- Existing-Inoperable: 547 MW
- Existing-Other: 0 MW
- Future-Planned: 0 MW

Most generation in the Québec Area is hydro (93 percent of Installed Capacity) owned and operated by Hydro-Québec Production (HQP). Variable resources include wind resources, owned and operated by Independent Power Producers and some biomass. Installed nameplate capacity is expected to be 1,814 MW in December 2012. A small amount of capacity (281 MW) is generated by biomass. Two fossil fuel generating stations have been permanently retired since March 2012. The Tracy G.S. (450 MW) which was mothballed in the previous assessment is now permanently retired and the La Citière G.S. (280 MW) has been retired since May 2012. Moreover, the Gentilly-2 nuclear G.S. (675 MW) will be retired for decommissioning at the end of 2012. In addition, La Sarcelle G.S.'s last unit (50 MW hydro) should be in service later in winter or spring 2013. It is not assumed to be in service for this winter assessment.

Maximum capacity for hydro resources is set equal to the power that each plant can generate at its maximum rating during two full hours, while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions. Biomass and wind IPPs have signed contractual agreements with Hydro-Québec. Therefore, maximum capacity and expected on-peak capacity of biomass are equal to contractual values. These represent almost 100 percent of nameplate capacity. As for wind resources, maximum capacity is set equal to contractual capacity. The capacity contribution of wind power generation at peak is estimated to be 30 percent of nameplate capacity.

On-Peak Capacity Transactions

The Québec Area will need to purchase about 600 MW on short term markets to ensure resource adequacy for the 2012/2013 Winter Operating Period. All capacity purchases needed to ensure resource adequacy for the 2012/2013 winter operating period will be backed by Firm contracts for both generation and transmission. For exports, a total of 398 MW with neighboring areas are backed by Firm contracts.

Transmission

Most significant transmission facilities are expected to be in service for the winter operating period. Transmission maintenance outages are scheduled during summer operating periods because of the system's winter-peaking characteristic. Planned transmission outages are normally completed by December 1.

Synchronous Condenser CS23 at Duvernay substation in the Montréal area, which has been out of service since June 2008 due to a major transformer fault, will be back in service for the 2012/2013 Winter Operating Period. This will enhance transmission capability on the Southern Interface of the load area of the Québec system.

Transmission projects now under way and scheduled in service for this winter peak period concern mainly wind generation integration (seven projects totaling 760 MW), 120 and 230 kV Bécancour subsystem reinforcement and satellite substation integration (three substations). No delays are expected.

There are no specific major projects needed to maintain or enhance system reliability during the 2012/2013 winter. There are a number of regional projects now under way: the Limoilou 230/25 kV substation in Québec City, the l'Anse-Pleureuse 230/25 kV substation, the Neubois 120/25 kV substation and the Bécancour 230 and 120 kV system reinforcements are scheduled in service for fall 2012.

Finally, Hydro-Québec TransÉnergie (HQT) is proposing to install a new generation rejection Type III SPS at Bersimis-1 and 2 Generating Stations. The SPS should be operational before the winter. The SPS is required because a double-circuit 315-kV transmission line will be unavailable during work done to integrate three wind power plants on the Bersimis sub-system. Without the SPS, this outage would cause restrictions at Bersimis-1 and 2.

Operations

No particular operating problems concerning transmission equipment have been observed for the coming 2012/2013 Winter Operating Period. Despite the retirement of two fossil fuel generating stations, a significant additional amount of capacity (hydro, wind and biomass), demand response and energy efficiency were added to the system, so these withdrawals have no impact on the system's reliability.

Integration of wind generation resources is ongoing in Québec. There will be about 3,600 MW integrated into the system by 2015; for the 2012/2013 operating period, it is expected that 760 MW of additional nameplate capacity will be placed into service, bringing the total wind nameplate capacity to 1,814 MW. This has not yet led to any special System Operating Procedures. Total generation capacity has actually grown for the 2012/2013 winter, despite fossil fuel retirements. However, peaking capability has been reduced with the retirement of La Citière jet turbine G.S. (280 MW) which, when manned, was usually available within 10 minutes.

Interruptible Load

Interruptible load programs used to meet peak demand are planned with participating industrial customers, who are contacted before the peak period (generally during fall) so that their commitment to provide their capacity when called during peak periods is ascertained. These programs have been in operation for a number of years and according to the records, customer response is highly reliable.

There are two different load response programs in Québec and each program has different options. There are some limitations or restrictions on calling demand response. Firstly, these programs are not available during summer operating periods. In winter, some options are available twice a day; others are available once a day. There is a maximum number of calls and a maximum number of interruption hours over a year. Calls must be made 2 to 18 hours in advance depending on the options to be used. The Load Serving Entity in Québec accounts for these restrictions when evaluating resource adequacy in the Area.

Unusual Operating Conditions

Presently, Hydro-Québec TransÉnergie (HQT) has a 735-kV current transformer (CT) replacement program running for the next two years. CTs that will not be replaced before winter will be subject to a restricted-access area due to safety issues that could limit operator interventions in such substations until the replacements are completed; this will not significantly impact operations.

Vulnerability Assessment

Given the importance of hydroelectric resources within the Québec Area, an energy criterion has been developed to assess its energy reliability, stating that sufficient resources should be available to run through sequences of two or four consecutive years of low water inflows totaling 64 TWh and 98 TWh respectively, and having a 2 percent probability of occurrence (system consumption was approximately 186 TWh in 2011). Normal hydro conditions are projected for the winter season and reservoir levels are expected to be sufficient to meet both peak demands and daily energy demand.

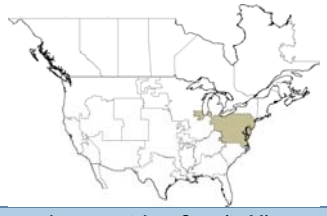
PJM

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**130,222**
Load-Modifying Demand Response	0
Net Internal Demand	**130,222**

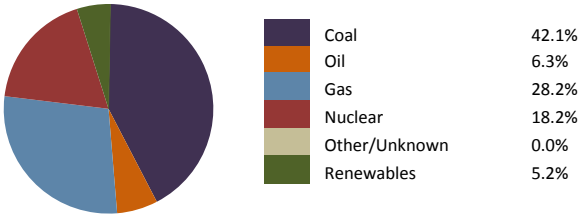
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	130,711
Actual Demand	130,222

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	581
Net Capacity Transactions (Firm and Expected)	217
Existing-Certain and Future-Planned Capacity	181,669
Anticipated Resources	**182,467**
Anticipated Reserve Margin (%)	**40.12%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**182,467**
Prospective Reserve Margin (%)	**40.12%**
NERC Reference Margin Level (%)	**15.60%**

Assessment Area Capacity Mix



Planning Reserve Margins

The PJM projected (existing and anticipated margins are the same) reserve margin for winter 2012/2013 is 40.1 percent. This level is well in excess of the PJM Required Reserve Margin[86] of 15.6 percent. The Reserve Margin calculation includes total forecasted load, Existing Certain generating resources, net transfers and Energy Efficiency treated as a resource. Demand-Side management is not included in the reserve margin calculations during this winter.

Demand

The PJM RTO 2011/2012 winter peak was 122,565 MW that occurred on January 3, 2012, hour ending 1900. On a weather-normalized basis, the PJM RTO 2011/2012 winter peak forecast was 130,711 MW. The difference can be attributed to a relatively mild winter in most of the PJM region. The forecast for the 2012/2013 PJM RTO winter peak is 130,222 MW. The combination of the new economic driver model and a downward revision to the economic outlook for the PJM area has resulted in almost the same peak and energy forecasts compared to last year's report. This year's forecast reflects PJM's adoption of an independent consultant's recommendation to replace the load model's previous economic driver (Gross Metropolitan Product) with a variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment).

Demand-Side Management

The total amount of Energy Efficiency for the PJM area expected to be available on peak for winter 2012/2013 is 581 MW. PJM Demand Response (DR) is not secured for the winter season except for DR used for operating reserves.

Energy Efficiency programs included in the 2012/2013 load forecast are impacts approved for use in the PJM RPM. Measurement and verification of energy efficiency programs are governed by rules specified in PJM Manual 18B - Energy Efficiency Measurement & Verification.[87] DR used for reserves is limited by the RFC standard BAL-002-RFC-02 to 25 percent of the Operating Reserve requirement. This type of DSM is typically fully subscribed and can range up to approximately 2,000 MW during a winter peak day.

[86] http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/2011-rrs-study.ashx.
[87] http://www.pjm.com/~/media/documents/manuals/m18b.ashx.

Generation

There is 181,669 MW of Existing-Certain generation in PJM to meet this winter's peak load. There is 4,825 MW of Existing-Other generation in PJM this winter. This amount is composed of wind and solar derates only. No Existing-Inoperable generation is accounted for in PJM. The predominant source of fuel in PJM is coal at approximately 42 percent of total Existing-Certain capacity. Next is natural gas at 26 percent of total Existing-Certain capacity and nuclear at 18 percent of total Existing-Certain capacity. No capacity resource changes are expected though the winter of 2012/2013.

Please see the table below for PJM generator retirements since May 2012.

Unit	Capacity (MW)	Transmission Zone	Age (Years)	Fuel Type	Actual Deactivation Date
Walter C Beckjord 1	94	DEOK	59	Coal	May-2012
Buzzard Point East Banks 1, 2, 4-8	112	PEP	39	Diesel	May-2012
Buzzard Point West Banks 1-8	128	PEP	39	Diesel	May-2012
Eddystone 2	309	PE	49	Coal	May-2012
Elrama 1	93	DUQ	59	Coal	June-2012
Elrama 2	93	DUQ	59	Coal	June-2012
Elrama 3	103	DUQ	57	Coal	June-2012
Kearny 10	122	PSEG	39	Natural Gas	June-2012
Kearny 11	128	PSEG	40	Natural Gas	June-2012
Niles 2	108	ATSI	58	Coal	June-2012
Benning 15	275	PEP	39	Oil	July-2012
Benning 16	275	PEP	35	Oil	July-2012
Crawford 8	319	ComEd	50	Coal	August-2012
Crawford 7	213	ComEd	53	Coal	August-2012
Fisk Street 19	326	ComEd	52	Coal	August-2012
Albright 1	73	APS	59	Coal	September-2012
Albright 2	73	APS	59	Coal	September-2012
Albright 3	137	APS	57	Coal	September-2012
Armstrong 1	172	AP	53	Coal	September-2012
Armstrong 2	171	AP	52	Coal	September-2012
Bay Shore 2	138	ATSI	53	Coal	September-2012
Bay Shore 3	142	ATSI	48	Coal	September-2012
Bay Shore 4	215	ATSI	43	Coal	September-2012
Eastlake 4	240	ATSI	55	Coal	September-2012
Eastlake 5	597	ATSI	39	Coal	September-2012
R Paul Smith 3	28	AP	64	Coal	September-2012
R Paul Smith 4	87	AP	43	Coal	September-2012
Rivesville 5	35	APS	68	Coal	September-2012
Rivesville 6	86	APS	60	Coal	September-2012
Vineland 10	23	AE	41	Coal	September-2012
Willow Island 1	51	APS	63	Coal	September-2012
Willow Island 2	138	APS	51	Coal	September-2012
Niles 1	109	ATSI	58	Coal	October-2012
Elrama 4	171	DUQ	51	Coal	October-2012
Potomac River	482	PEP	62	Coal	October-2012
Total Deactivated:	**5,866**	-	-	-	-

No additional units are expected to retire during the winter 2012/2013 assessment period. Any addition of new generation or generator uprates adds to the PJM reserve margin. Any generation retirements subtracts from the PJM reserve margin.

The nameplate value of wind generators in PJM for this winter is 5,400 MW and the on-peak expected value is 700 MW. The nameplate value for solar units in PJM is 103 MW and the on-peak expected value is 39 MW. Hydro and biomass units are not derated. Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual unit's capacity factor.

Capacity Transactions

All transactions are Firm for both specific generation and transmission. No currently accepted Firm contracts end during the 2012/2013 winter peak season. PJM has no reliance on outside assistance for emergency imports. There have been no addition of import/export capabilities for the 2012/2013 winter.

Transmission

There are no project delays or temporary service outages for transmission facilities (lines or transformers) that will impact reliability during this winter. No new transmission projects are needed to go in service during this winter to maintain reliability.

Operations

PJM performs both an Operations Analysis Task Force (self assessment) and interregional assessment(s) using expected peak winter conditions to determine system adequacy and to identify system problems. No unique issues were observed.

PJM processes incorporate announced retirements into the PJM Regional Transmission Planning Process. Planning and Operation staff analyze the need to implement RMR contracts to extend the retirement date until transmission reinforcements are placed into service. Additional Regional Transmission Expansion Plan (RTEP) projects have been identified based on projected capacity reductions. No general operational concerns for the coming 2012/2013 winter season have been identified in PJM.

PJM staff continues to manage the impact of approximately 16,600 MW of announced generation retirements and an additional 6,020 MW of projected retirements through 2018, mostly resulting from environmental legislation (approximately 5,700 MW retirement scheduled in 2012).

Vulnerability Assessment

PJM has very little hydro generation and reservoir levels are adequate. Any one specific generator outage, even if it is long-term, can be replaced with other resources available within PJM.

PJM has developed a Wind Power Forecast tool and visualization to assist operations. This tool enhances the operator's ability to more accurately project how much power can be expected from wind resources. Expected values typically provide forecasts for near real-time and hourly time increments.

PJM has established rules/procedures to ensure fuel is conserved to maintain an adequate level on-site fuel supplies under forecasted peak load conditions. PJM coordinates with neighboring entities and gas pipelines to quickly address fuel issues.

SERC-E

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**43,150**
Load-Modifying Demand Response	1,504
Net Internal Demand	**41,647**

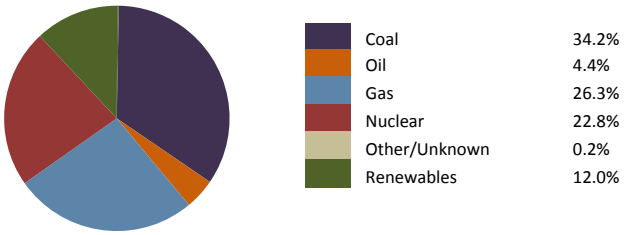
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	42,459
Actual Demand	40,151

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	1,430
Existing-Certain and Future-Planned Capacity	54,307
Anticipated Resources	**55,737**
Anticipated Reserve Margin (%)	**33.83%**
Existing-Other and Future-Other Capacity	52
Prospective Resources	**55,789**
Prospective Reserve Margin (%)	**33.96%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

Reserves are appropriate for providing an adequate and reliable power supply during the 2012/2013 winter. Entities do not use a regional/reporting area target or Reserve Margin criteria. No operational problems are anticipated that would detract from these projected Reserve Margins.

Demand

The 2011/2012 winter actual demand was 40,151 MW while the peak Total Internal Demand forecast for 2011/2012 was 42,459 MW. The differences between these figures are primarily due to mild seasonal weather and reduced demands stemming from lingering economic conditions. This winter's peak demand forecast is projected to be 43,150 MW, which is 1.6 percent higher than the prior year's forecast. Increases are due to anticipated economic growth and normalized winter conditions. Some entities within the reporting area are updating their forecasting models for the most recent regional and local economic projections. .

Demand-Side Management

Demand Response and Energy Efficiency programs are projected to be 1,687 MW and 496 MW, respectively. Existing Demand Response resources are primarily used for reducing peak loads associated with system emergencies and maintaining adequate capacity reserves.

Generation

Companies within the SERC-E reporting area expect to have 52,353 MW of Existing-Certain, 10 MW of Existing-Other, and 64 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during this time period. Coal is the primary source of fuel within this area, representing 35 percent of Existing-Certain Resources, with the next largest fuel source of gas/dual fuel at 27 percent. Additionally, 2,389 MW of Future-Planned resources are projected to be added leading up to and during the period. This new generation capacity is scheduled to come on-line to offset planned retirements. By December 2012, approximately 90 MW of reduced generation is expected during the winter due to unit retirements. As a result of the recently finalized environmental regulatory requirements, entities will continue to assess the risk on the system and plan accordingly to meet demand. No additional generation retirements have been announced. Individual entity's internal company discussions have included scenario planning and mitigation measures. Mitigation options must be explored and considered as part of any decision to retire existing generating units.

Entities have scheduled approximately 1,445 MW of new generation in-service prior to the 2012/2013 winter season. A new combined cycle facility is scheduled to be in-service by October 2012 and will be rated for a net output of 620 MW. This generation will offset previously retired coal-fired generation. In January of 2013, 1,049 MW of new generation is scheduled to be in-service. System upgrades are being made to accommodate the new generation. Before December 2012, entities plan to retire 1,755 MW of generation, approximately 68 percent of retirements are from coal-fired generation. Approximately, 2,300 MW are expected to be off-line throughout the period.

A hydro unit rated at 50 MW is reported to be off-line for an extended outage. Entities continue to assess long-term outages and report significant changes to SERC staff throughout the year. Behind-the-meter and distributed generation are reported to be 0 MW. However, entities expect 630 MW of non-traditional resources for the winter period.

For the upcoming winter season, companies within the SERC-E reporting area expect to have 97 MW of biomass, 28 MW of solar, and 6,139 MW of hydro/pumped storage capacity on-peak. SERC does not collect the nameplate output of the units, so no maximum capacity MW is available. Overall, variable resources are limited within this area. However, they are assessed for their availability to meet the needs of customers reliably and economically, based on the requirements of the regulatory standards and their ability to maintain flexibility for long-term resource decisions. As required, entities will continue to evaluate these and other renewable resources as part of their integrated resource planning process.

Capacity Transactions

Entities within the SERC-E reporting area expect net capacity transaction as listed in the summary table for the 2012/2013 winter. All resources are used in Reserve Margin calculations for the reporting area. Of all imports/exports, very few are associated with Liquidated Damages Contracts (LDCs), in which the contracts are considered 100 percent “make-whole.”

To meet Planning Reserve Margins during the period, entities within the SERC-E reporting area do not rely on resources outside the region for emergency imports, reserve sharing, or outside assistance/external resources.

Transmission

The existing transmission projected in-service dates are not at risk for the assessment period.

Several large-scale construction projects are planned and will be implemented in phases around seasonal peak load periods to mitigate reliability concerns associated with line clearances and non-routine operating arrangements during higher seasonal load periods. Additionally, no specific projects have been identified that would maintain or enhance reliability for the winter period.

Operations

For hydro units, lake levels are carefully managed. To the extent weather conditions and inflows permit, entities manage hydro capacity limitations during seasonal peak load periods.

Overall, there are no other unusual operating conditions anticipated that could impact reliability for the winter.

Vulnerability Assessment

Resource adequacy studies help determine entity Reserve Margins in the reporting area. The study recognizes, among other factors; load forecast uncertainty due to economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. Uncertainties may also be addressed through capacity margin objectives and practices in other resource assessments at the operational level. These operational studies may be performed annually using input provided from Generator Operators. As conditions warrant, entities may need to perform additional assessments to mitigate challenging conditions that may occur to the system. Entities report that historical studies have determined that a minimum reserve of 12 percent is adequate for reliability.

Entities maintain enough diesel fuel to run the generation units for an order cycle of fuel. Firm gas supply and transportation contracts are monitored to align with inventory levels of coal and oil supply, natural gas storage, and generation capacity margins. Entities have ongoing communications with commodity and transportation suppliers to

communicate near-term and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel, or redundant fuel supplies may also be used to mitigate emergencies in the fuel industry or economic scenarios. On-site fuel oil inventory allows for seven-day operations on some units. This is considered to be ample time to coordinate with the industry to obtain adequate supplies. Contracts are in place for months and often years, into the future. Vendor performance is closely monitored, and potential problems are addressed long before issues become critical. Contracts and market positions are considered to be diverse enough to mitigate any supply or delivery issues.

SERC-N

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**45,081**
Load-Modifying Demand Response	1,592
Net Internal Demand	**43,489**

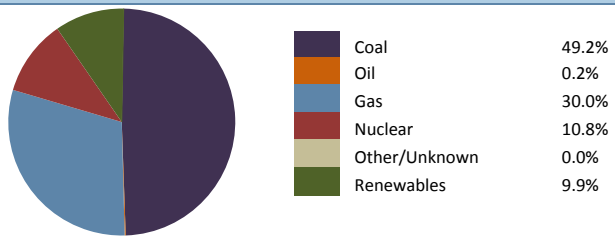
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	47,123
Actual Demand	39,580

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-236
Existing-Certain and Future-Planned Capacity	57,831
Anticipated Resources	**57,595**
Anticipated Reserve Margin (%)	**32.44%**
Existing-Other and Future-Other Capacity	6,290
Prospective Resources	**63,885**
Prospective Reserve Margin (%)	**46.90%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

The SERC-N Assessment Area had planned for adequate Planning Reserve Margins during the 2012/2013 winter season and this is now further enhanced by lower projected loads. Entity results show that they are planning for reserves of at least 15-17 percent for the upcoming winter. Reserves forecast for the season are adequate, assuming typical weather and expected operating conditions. Currently there are no potential issues that could lead to detraction from reported projections.

Demand

The difference between the 2011/2012 winter peak demand forecast of 47,123 MW and the actual of 39,580 MW is primarily due to extremely mild weather conditions. The impact of a new rate structure on consumer behavior may also have had an effect. This winter's peak demand forecast is 45,081 MW. The decrease from the prior year's forecast is due to reduced load expectations. Assumptions have been adjusted for normal weather and current economic conditions for both the US and regional economies. Since the start of the economic recession, some entities reported that they have significantly adjusted their long-term models and enhanced near-term hourly forecast models.

Demand-Side Management

Demand Response and Energy Efficiency are projected to be 1,592 MW and 139 MW, respectively. These load control programs allow entities to reduce demand and control voltage as needed for reliability purposes during peak loads. Demand Response is projected to be 3.5 percent of Total Internal Demand for the upcoming winter, for a 0.7 percent increase from the 2011/2012 winter season. The primary source of current Demand Response is a direct load control (DLC) program and an interruptible product portfolio.

Generation

Entities within the SERC-N reporting area expect to have 57,843 MW of Existing-Certain, 2,576 MW of Existing-Other, and 152 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during the 2012/2013 winter season. Coal is the primary fuel source within this area, representing 43.3 percent of Existing-Certain resources. The next largest fuel source for generation is gas/dual fuel with 33.3 percent of Existing-Certain resources. No Future-Planned resources are planned for the season. Between May and October 2012 there were 2,209 MW of coal-fired and hydro generation retirement, deferments, derates or other reductions. No additional capacity reductions are expected to occur during the winter season.

16 MW of Biomass, 156 MW of wind, and 6,389 MW of hydro/pumped storage are expected on-peak. The capacity values of wind contracts are usually based on contract terms with an assumed contribution at system peak of 12 percent of the wind generator nameplate ratings. This factor is consistent with the credit applied by RTOs to other wind resources in that same geographical area. The contribution from customer-owned solar resources is based on solar insolation values at the time of the 2012/2013 winter peak.

Hydro capacity projections are based on modeling the competing requirements for management of the Tennessee River system. Balancing these requirements and factoring in anticipated weather conditions for the winter season allows estimation of energy production from the conventional hydro facilities.

Capacity Transactions

Net capacity transactions for the SERC-E Assessment Area are shown in the summary table above. The majority of these imports/exports into and out of the SERC-N Assessment Area are backed by Firm contracts for both Firm specific generation and transmission and do not include "make-whole provisions." Imports and exports have been accounted for in the Reserve Margin calculations for the reporting area.

Contingency reserves and emergency imports are obtained from a variety of resources such as Midwest ISO (under Attachment RR of the Midwest ISO ancillary services market tariff), together with 350 MW from PJM and 1,347 MW from the TEE Contingency Reserve Sharing Group (TCRSG). Entities are not anticipating additional import/export capabilities for the winter season.

Transmission

If week-ahead, real-time, or next day operating studies reveal potential reliability issues, action plans such as operational guides exist to address and mitigate the issue. Local area generation may be re-dispatched or transmission elements reconfigured to alleviate anticipated next contingency overloads. No transmission issues have been identified that will impact reliability during the 2012/2013 winter season.

Operations

Routine operating studies (bi-annual load forecast study; monthly, weekly, and daily operational planning efforts; annual assessment of winter peak and temperature, etc.) are performed to assess the system. These studies take into consideration weather, demand, unit availability, and upcoming capacity reductions to help to address risk. Based on the results of these studies entities do not anticipate operational problems.

Operational guides are also in place to mitigate impact of variable resources as needed. Net scheduled interchanges plus the operating minimum on all the generators are assessed to address low minimum load conditions. System operators have the authority to take units off-line to address generation operating minimum issues as needed.

There are no unusual operating conditions anticipated that would impact reliability for the winter season.

Vulnerability Assessment

Resource adequacy assessments covering the next 36 months are performed monthly to assist in identifying limitations or constraints that may impact seasonal adequacy. No system reliability concerns for the season have been identified in the latest resource adequacy studies. Resource availability, fuel availability, hydro and reservoir conditions are expected to be normal during the winter season. Preventative actions such as maintaining adequate fuel inventories, purchasing incremental fuel supplies, and obtaining dual fuel options and additional purchased power contracts, will help ensure operational concerns are not an issue for the season.

Entities are aware of potential risks associated with current and pending environmental regulations/limitations. In order to maintain compliance entities perform studies, re-establish operational procedures, and implement projects. Outage coordination procedures assist in avoiding or mitigating system reliability impacts. No reliability impacts are anticipated for the upcoming winter season.

Having a diverse portfolio of suppliers is common within the SERC-N reporting area. Entity fuel departments typically monitor supply conditions on a daily basis through review of receipts and coal burns, and interact daily with both coal and transportation suppliers to review situations and foreseeable interruptions. Any identifiable interruptions are assessed with regard to desired inventory levels. By purchasing from different regions, coal is projected to move upstream and downstream to various plants. Some plants have the ability to reroute deliveries among themselves. Some stations having coal delivered by rail can also use trucks to supplement deliveries.

Entities have reported that they maintain fuel reserve targets greater than 30 days of on-site coal inventory. Fuel supplies are reported to be adequate and readily available for the winter season. Multiple entities have contracts for local coal from area mines. In the event of a potential supply or transportation disruption, entity processes may include the delay or cancelation of planned unit maintenance outages or derates.

SERC-SE

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**45,620**
Load-Modifying Demand Response	1,882
Net Internal Demand	**43,738**

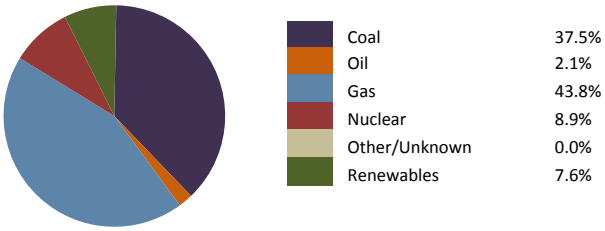
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	44,259
Actual Demand	42,811

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-2,262
Existing-Certain and Future-Planned Capacity	67,102
Anticipated Resources	**64,840**
Anticipated Reserve Margin (%)	**48.25%**
Existing-Other and Future-Other Capacity	2,412
Prospective Resources	**67,253**
Prospective Reserve Margin (%)	**53.76%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

The SERC-SE Assessment Area is projecting an adequate Planning Reserve Margin during the 2012/2013 winter period. Entities do not adhere to any regional/reporting area targets or the NERC Reference Reserve Margin criteria. However, the State of Georgia requires maintaining at least 13.5 percent near-term (less than 3 years) and 15 percent long-term (3 years or more) Reserve Margin levels for investor-owned utilities or the largest operating company within the state. Through the system's intercompany interchange contract, this Reserve Margin requirement has been applied to all system operating companies and is verified triennially via resource adequacy studies for the entire system. Winter reserves for this summer-peaking area are anticipated to be adequate due to reductions in load forecast resulting from the recent recession and continued economic recovery, assuming typical weather and operating conditions. There are no known operational issues or circumstances expected to detract entities from these projections.

Demand

Increases from the 2011/2012 winter peak demand forecast of 44,459 MW and this winter's peak demand forecast, which is projected to be 45,620 MW, are primarily due to economic recovery conditions. The 2011/2012 winter actual peak demand of 42,811 MW was lower than the 2011/2012 winter peak demand forecast. Differences in demand were due to warmer than normal weather. A change in the load class composition due to the economic recovery has increased the peak forecast for the 2012/2013 winter period.

Demand-Side Management

Demand Response is projected to be 1,882 MW, and Energy Efficiency is included in the Entities' Load Forecasts. These programs allow entities within the reporting area to have control over various amounts of load and capacity when needed for reliability purposes. Extreme real-time pricing response is considered as a capacity resource.

There is no significant change in the amount of Demand Response since last year, as Demand Response is projected to be 4.1 percent of Total Internal Demand, a 0.8 percentage point increase.

Generation

Utilities within the SERC-SE reporting area expect to have 66,296 MW of Existing-Certain, 2,412 MW of Existing-Other, and 0 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during this time period. Oil/Gas/Dual Fuel are the primary sources of fuel within this area, contributing 45.2 percent of Existing-Certain resources. The secondary source of fuel is Coal representing 38.3 percent of Existing-Certain resources. In addition, 921 MW of Future-

Planned resources are expected to be added during the period. 76 MW of retirements, deferments, derates or other reductions will occur on the system during the month of December. There are no significant negative impacts to reliability anticipated for the winter period.

Approximately 974 MW of new generation has been added since the last winter season. There are neither new generator uprates in service nor any generation expected to be taken out of service during the period. A 110 MW unit has been on an extended forced outage and is expected to return to service by September 2012. Behind-the-meter generation is reported to be 0 MW. However, there are 115 MW of Other/Unknown resources anticipated for the period. Extended outages are not expected during this timeframe.

For the upcoming winter season, 67 MW of biomass, 4 MW of solar, and 4,936 MW of hydro/pumped storage are expected on-peak. Given that SERC does not collect the nameplate output of the units, no maximum capacity data is available. Only Firm capacity is counted toward the peak in Reserve Margin calculations. However, Future-Planned biomass generation is included in the Integrated Resource Plans at less than the nameplate capacity for converted boilers, and at nameplate capacity for units receiving new boilers. Landfill gas facilities are included at their nameplate ratings. Contracts with external parties for these resources usually require proof of capacity and allow for capacity payment penalties for excessive unavailability and derating events.

Currently, entities are developing methods for incorporating variable resources into its planning processes. Variable resources are currently evaluated by analyzing their historical or projected output profiles. The result will be a determination of the comparative capacity value to that of a typical combustion turbine (CT) on the system.

Capacity Transactions

Utilities within the SERC-SE reporting area expect the net capacity transactions listed in summary table for the 2012/2013 winter season. These imports and exports have been included in the Reserve Margin calculations for the reporting area. All imports/exports were reported to be backed by Firm contracts for both generation and transmission, but none are associated with LDCs and only three (568.8 MWs) are considered “make whole.”

Reporting entities maintain emergency-reserve sharing agreements with organizations internal to the area and other contract agreements with neighboring utilities provide capacity for outages of specific generation. Total emergency MWs from these imports were not reported, but are available as needed. Overall, entities are not dependent on outside imports or transfers to meet the demands of its load. Starting in January 2013, an additional wind power purchase of 202 MW will be available having Firm transmission.

Transmission

Currently, there are no concerns with meeting in-service dates for transmission improvements or specific projects needed to maintain reliability. Entities consistently evaluate the transmission system through operating studies and a model construction process. Additionally, there are no specific projects that were identified to maintain or enhance reliability.

Operations

Entities perform studies of operating conditions up to 13 months into the future. These studies are updated on a monthly basis and include the most current information regarding load forecasts, transmission and generation status, and Firm transmission commitments for the time period studied.

Regularly, entities in the area experience significant loop flows due to transactions external to the area. The availability of large amounts of excess generation within the Southeast reporting area results in fairly volatile day-to-day scheduling patterns. The transmission flows are often more dependent on weather patterns, fuel costs, or market conditions outside the area. Significant changes in gas pricing dramatically impact dispatch patterns. All transmission constraints identified in current operational planning studies for the 2012/2013 winter season can be mitigated through generation adjustments, system reconfiguration, or system purchases. A large number of transmission and generator outages are necessary for the

fall and winter seasons to maintain reliability and make system changes necessary to ensure compliance with new environmental regulations. Extensive coordination efforts are currently underway to manage scheduling challenges and avoid significant negative impacts to system reliability.

Hydroelectric units in the area are run in cooperation with the U.S. Army Corps of Engineers to maintain water levels and river flow. As a result of federal and state regulations, fossil generating units in the area have numerous operating limits related to air and water quality permit limits. A number of these units have unique limits on operations and emissions. Some are annual limits while others are seasonal, most particularly during the summer season. These restrictions have traditionally been continually managed in the daily operation of the system while maintaining reliability. New and more stringent environmental requirements pose a short-term challenge in making all the necessary system and plant modifications needed. [8.9]Overall, no environment restrictions or unusual conditions are projected to impact the reliability on the Bulk Electric System for the upcoming winter season.

Vulnerability Assessment

To address extended generator outages, extensive coordination efforts are currently underway to manage scheduling challenges and avoid capacity shortages due to any overlapping generation outages.

Individually, entities in the area continue to adjust internal planning studies and facility evaluations to address compliance issues regarding upcoming environmental regulations. Adverse reliability impacts from the regulations are not expected for the upcoming winter season.

The fuel supply infrastructure, fuel delivery system, and fuel reserves are all adequate to meet peak demand. Various companies within the SERC-SE reporting area have; Firm transportation diversity, diverse fuel mixes, gas/coal storage, Firm pipeline capacity, and on-site fuel supplies to meet the peak demand. When situations limit supply, established communication methods allow for additional supplies. These lines of communication include daily e-mails, phone calls, internet accessibility, SCADA, and instant messaging so that entities are well aware of fuels moving to various generating stations or to storage.

Some utilities have implemented fuel storage and coal conservation programs, as well as various fuel policies, to address concerns. Policies are also in place to ensure that fuel storages are filled well in advance of hurricane season (by June 1st of each year). These tactics help to ensure balance and create flexibility to serve anticipated generation needs. Vendor relationships with coal mines and coal suppliers, daily communication with railroads for transportation updates, and ongoing communication with the coal plants and energy suppliers ensures that supplies are adequate and potential problems are communicated well in advance to enable adequate response time.

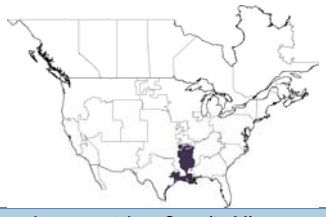
SERC-W

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**20,008**
Load-Modifying Demand Response	11
Net Internal Demand	**19,997**

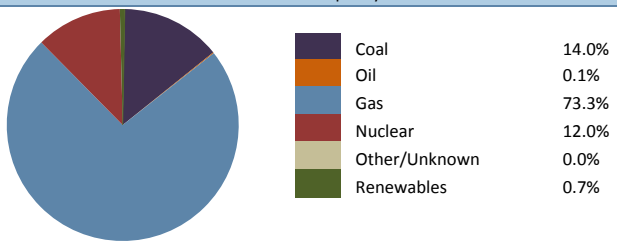
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	19,931
Actual Demand	19,868

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-1,701
Existing-Certain and Future-Planned Capacity	35,894
Anticipated Resources	**34,193**
Anticipated Reserve Margin (%)	**70.99%**
Existing-Other and Future-Other Capacity	5,002
Prospective Resources	**39,195**
Prospective Reserve Margin (%)	**96.00%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

The Reporting area is projecting adequate Planning Reserve Margins during the winter period, given that none of the Planning Reserve Margins will fall below the NERC Reference Margin Level of 15 percent. Entities within this area do not adhere to any regional/reporting area targets or Reserve Margin criteria. Contributing factors to adequate margins are attributed to existing and owning resources, limited and long-term purchase contracts. Potential deactivations and anticipated unit outages are also factored into the plans to meet the target Reserve Margin when developing plans for the season.[88] There are no other anticipated reliability concerns for the 2012/2013 winter season.

Demand

The 2011/2012 winter actual demand was 19,277 MW and the peak demand forecast was projected to be 19,931 MW. Differences in the 2011/2012 winter actual and forecast are due to mild weather, while the forecast is based on normal weather. This year's 2012/2013 winter demand forecast is 20,176 MW. The expansion of industrial customers was a factor in an increased forecast, given that the projections resulted in fewer loads than originally expected. Forecast assumptions are unchanged for this year's forecast predictions. Energy requirements were expected to be nearly unchanged, due to the effect of slow economic recovery. Therefore the peak demand forecast does not reflect much growth. However, load growth remains high in the western portion of the area's Texas footprint where residential and commercial load growth is spurred by stronger economic growth. Specific industrial and commercial expansion projects are also driving load growth in service areas in the south Louisiana area.

Demand-Side Management

Demand Response and Energy Efficiency are projected to be 11 MW and 0 MW, respectively. These programs are used to reduce peak demand on entity systems within the area. DSM programs among the utilities in the reporting area include: interruptible load programs for larger customers, direct-control load management programs for agricultural customers, and a range of conservation/load management programs for all customer segments.

Generation

Companies within the SERC-W reporting area expect to have 35,894 MW of Existing-Certain, 5,002 MW of Existing-Other, 1,074 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during the winter

[88] Individual entity criteria also help to establish resource adequacy by; allocations assigned as a member of the Southwest Power Pool (SPP) Reserve Sharing Group, Balancing Authority's (BAs) most severe single contingency, load forecast, and reserve requirement using historical allocations, and Loss-of Load expectation studies (0.1 day/year).

period. Oil/Gas/Dual Fuel units are the primary sources of fuel within this area, representing 66.2 percent of Existing-Certain resources. No Future-Planned resources are projected to be added during the period. Entities have reported 244 MW capacity reductions during the months of May through October 2012, and 421 MW of reductions during the upcoming winter. Significant negative impacts on capacity are not anticipated for the period.

Entities expect 178 MW of additional generation and uprates during the winter season. There are 421 MW of generation out of service during portions of the period. In addition, 411 MW will be brought back into service for the period. Behind-the-meter generation is reported to be 1,235 MW. Even though there are no ongoing long-term outages, entities have reported 141 MW of Other/Unknown resources in-service for the period.

Variable resources such as biomass, solar, and wind are not expected to be on peak during the season. However, 299 MW of hydro/pumped storage will contribute toward on-peak capacity. Only Firm capacity is counted toward the peak in calculations. In most cases, entities do not count variable resources due to its irregularity during peak demand periods. However, other entities consider wind values based on a time-period method using monthly capacity value measures. The process first examines the highest ten percent of load hours for the respective month, and ranks wind generation in those hours from high to low. The wind generation value that exceeds 85 percent of the time is defined as the capacity value of the wind resource. This method is based on research from various sources discussing estimation of the capacity value of wind resources. For base load resources like biomass and in-stream hydro, the assumption is 100 percent of the rated capacity value.

Capacity Transactions

Entities within the SERC-W reporting area expect the capacity transactions listed in the summary table for the 2012/2013 winter. These imports and exports have been accounted for in the Reserve Margin calculations for the reporting area. All contracts are Firm agreements for both generation and transmission. All the capacity contracts are unit contingent with corresponding Firm transmission sourced from the facility.

Reporting entities in the area are dependent on certain imports, transfers, or contracts to meet the demands of its load. Total emergency MWs from these imports were not reported, but are available as needed. In addition, there are no new import/export contracts available for 2012/2013 Winter Season.

Transmission

Entities within the reporting area are not expecting any delays in meeting in-service dates for projects scheduled for the winter assessment period. Additionally, there are no significant transmission facility outages that impact Bulk Electric System reliability. Prior to approval of any proposed maintenance outages, studies are completed to identify any impacts on reliability. No transmission issues have been identified that will impact reliability during the 2012/2013 winter season.

Operations

Companies within the SERC-W reporting area regularly participate in SERC NTSG seasonal reliability studies and in the ERAG MRO-RFC-SERC West-SPP (MRSWS) interregional studies. These studies test import capabilities into the area and are expected to predict increases/decreases for all transfer directions studied. Preliminary study results indicate that transfer capabilities for the upcoming winter season are expected to be at or near the test levels. Entities also do not expect any adverse operational impacts from capacity reductions of any kind during the upcoming winter period. The operational concerns for the area are the unseasonably cold temperatures that can occur, but there are well established processes and procedures for addressing these unusual circumstances.

Due to an insignificant amount of variable generation connected to the distribution system, there are no concerns about integrating these resources onto the system.

Vulnerability Assessment

Existing and owned resources, limited and long-term purchase contracts, as well as potential deactivations and anticipated unit outages to plan and procure resources needed to meet the target Reserve Margin are considered when developing the one-year and 10-year resource plan. Loss-of-Load studies are also performed annually for the current year based on updated load forecast and unit availability data. The long-term test of resource adequacy is met by achieving a 16.85 percent Planning Reserve Margin. Currently, there are no concerns from long-term drought conditions, unit outages, Demand Response, variable generation, or other operational issues.

With the completion of the joint Acadiana Load Pocket Projects (Phase 1 was completed in 2011 and Phase 2 completed in 2012), the Acadiana area in south Louisiana experience no reliability issues in the winter of 2011 or the summer of 2012. These projects, which created a new 230 kV transmission overlay for the area, helps move power more effectively from the stronger sources on the northern boundary of the Acadiana Load Pocket and inject more directly into the underlying system further south. This new 230 kV overlay addressed the historical transmission congestion issues that have occurred in prior seasons and is expected to continue to help alleviate future congestion in the area. With these new facilities in place no reliability issues are expected in the Acadiana area for the upcoming 2012 Winter season.

Planned outages are normally scheduled outside of summer and winter peaking periods. The following factors are taken into account when compiling seasonal outage schedules: System Reserves, Load Pocket Reserves / Area Import Limits, Load Pocket Required Must Run criteria (Owned/Contracted), Co-owner Constraints, Winter Fuel Units (Firm Fuel Capability), Hurricane Season (Firm Fuel Capability), Contract Unit Outages, Diversified Scheduling of CCGT Units, Diversified Scheduling of Black Start Units, Outage Balance Between Spring and Fall Seasons, and Cost of Replacement Power. No operational concerns are expected for the season.

Fuel supply or delivery problems are not anticipated for the period. Utilities maintain enough diesel fuel to run the generation units for an order cycle of fuel. Firm gas supply and transportation contracts are monitored to align with inventory levels of coal and oil supply, natural gas storage, and generation capacity margins. Entities have ongoing communications with commodity and transportation suppliers to communicate near-term and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel, or redundant fuel supplies may also be used to mitigate emergencies in the fuel industry or economic scenarios. On-site fuel oil inventory allows for seven-day operations on some units. This was considered to be ample time to coordinate with the industry to obtain adequate supplies. Contracts are in place for months, and often years, into the future. Vendor performance is closely monitored and potential problems are addressed long before issues become critical. Contracts and market positions are considered to be diverse enough to mitigate any supply or delivery issues as they occur.

SPP

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**35,810**
Load-Modifying Demand Response	732
Net Internal Demand	**35,079**

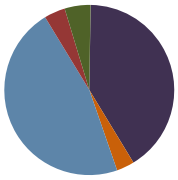
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	41,089
Actual Demand	35,810

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	200
Net Capacity Transactions (Firm and Expected)	-371
Existing-Certain and Future-Planned Capacity	80,508
Anticipated Resources	**80,337**
Anticipated Reserve Margin (%)	**129.02%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**80,337**
Prospective Reserve Margin (%)	**129.02%**
NERC Reference Margin Level (%)	**13.60%**

Assessment Area Capacity Mix



Coal	41.0%
Oil	3.4%
Gas	46.6%
Nuclear	4.0%
Other/Unknown	0.1%
Rewables	4.9%

Planning Reserve Margins

SPP Criteria requires members to maintain a minimum capacity margin of 12 percent which translates to a 13.6 percent Reserve Margin. SPP RTO is projected to have adequate Planning Reserve Margins for the assessment period as all of the planning reserve margins are well above the 13.6 percent reference reserve margin. This level of adequacy is supported by the SPP RTO's available generation fleet and the projected demand decrease projected for the winter timeframe.

The SPP RTO footprint is subject to extreme winter weather conditions that can impact demand and generation supply as evidenced in February 2011. Those conditions caused generation supply problems for a few members but did not negatively impact reliability for the broader SPP RTO assessment area. The region is even better prepared should extreme weather occur again this winter.

With the Federal Circuit Court's decision to vacate the Cross-State Air Pollution Rule (CSAPR), this regulation is not expected to impact the SPP RTO during the winter assessment period. The Environmental Protection Agency's (EPA) Mercury Air Toxic Standard (MATS) regulation will impact the SPP RTO region when it become effective, but it is not anticipated to cause reliability concerns for the 2012/2013 winter as discussed later in this assessment.

Demand

The projected non-coincident Total Internal Demand forecast for the 2011/2012 winter peak was 41,089 MW. The projected coincident 2012/2013 Total Internal Demand winter peak forecast is 35,810 MW. The actual 2011/2012 winter peak demand was 35,281 MW. The projected coincident forecast beginning with the 2012/2013 winter assessment uses modeling data submitted by the individual entities. In previous years SPP RTO has reported a non-coincident Total Internal Demand forecast based on aggregated member data. The increase in Estimated Diversity from the 2011-2012 winter assessment to the 2012/2013 winter assessment is due to SPP RTO performing the calculation instead of the individual balancing authorities. The ratio of actual peak coincident load to the modeled peak non-coincident load from the winter 2011-2012 was used to obtain the forecasted peak demand from the 2012/2013 winter model non-coincidental peak.

Demand-Side Management

Demand response programs in the SPP RTO footprint are voluntary and are primarily targeted for summer peak load reduction use. SPP RTO members include their own Demand Response and energy efficiency programs as reductions in their load forecasts. 726 MW of interruptible and non-controllable demand and 178 MW of direct control load

management will be available for use in reducing winter peak load. SPP RTO members report 235 MW of energy efficiency programs for the assessment period.

Generation

For the 2012/2013 winter assessment period, SPP RTO forecasts 78,631 MW of Existing- Certain; 0 MW of Existing-Other; and 0 MW of Existing-Inoperable Resources. The primary fuel sources in the SPP RTO footprint are gas (45 percent) and coal (37 percent). The higher Existing-Certain forecast, compared to previous assessments, is due to a change in the way SPP is reporting capacity resources. In the past, SPP RTO sent the assessments to the SPP Members and had them report their Expected-Certain resources. SPP RTO is now using the SPP Model Development Working Group model as a base case for all current year capacity resources, and will then subtract out all the reported outages. The use of the MDWG data set provides a consistent source of data for load, generation, and transmission topology for use in the NERC reliability assessments and SPP's transmission planning studies.

SPP RTO projects 597 MW of Future-Planned coal and 1,280 MW of Future-Planned wind resources to be added during the 2012/2013 winter of which 684 MW will be expected on peak. No upgrades or uprates are expected.

SPP RTO has added a total nameplate of 2,318 MW new wind generation, of which 70 MW is expected on peak, since the 2012 summer reporting season as shown below:

- 1,067 MWs of wind generation added in June
- 1,251 MWs of wind generation added in August

SPP RTO projects no capacity reductions to occur during the 2012/2013 winter season.

Because of the significant reserve margins in the SPP RTO assessment area for the 2012/2013 winter season, the capacity additions noted above are not expected to cause any short-term impacts.

For the 2012/2013 winter season SPP RTO projects less than 7 percent, based on historical data, of the total wind capacity of 6,992 MWs to be available on peak. Even though there has been a significant drought in the SPP region, no hydro capacity and conventional thermal unit reductions are expected during this season. The on-peak capacity values for variable resources are based on the 2011/2012 actual output percentages at winter peak.

Capacity Transactions

SPP RTO members, along with some members of the SERC Region, participate in a Reserve Sharing Group. Group members receive contingency reserve assistance from each other; however, due to the high reserve margin in the SPP RTO footprint, group participants within SPP generally transfer reserves into the SERC Region. Therefore, the group does not require support from generation resources located outside the SPP RTO Region.

Operations

As noted earlier in the assessment, two EPA regulations, the CSAPR and MATS, were expected to impact generation in the SPP RTO footprint. However, the CSAPR has been vacated and due to the timing of the MATS regulation, SPP RTO does not anticipate operational concerns for the upcoming winter season.

SPP RTO is currently working to implement a consolidated Balancing Authority within its footprint with centralized unit commitment as well as a day ahead energy market including ancillary services. This is expected to be in operation in early 2014. The centralized commitment and balancing activities are expected to ease the integration of a larger amount of variable generation. SPP RTO has implemented a centralized forecasting service for wind generation and is working with members to determine responsibility for provision of additional meteorological data in order to improve that forecast.

Vulnerability Assessment

Long-term (> 6 months) drought conditions exist across many areas of the SPP RTO footprint. However, the affected areas have minimal hydro facilities and unit derates have not occurred due to low cooling water or supply water levels. Since

heavy winter and spring rain totals tend to relieve the drought conditions, resource adequacy or operational concerns are not anticipated due to drought conditions for the upcoming winter.

Since SPP RTO has an abundant generation supply, significant long-term generator outages are not a potential concern. There are no short-term concerns about Demand Response programs being unresponsive or unavailable as SPP RTO exceeds its minimum reserve margin requirements even without relying on these programs.

To ensure the most efficient and effective use of renewable resources, SPP's operations staff must maintain and enhance its ability to project how much wind generation will be available to reliably serve load over given time periods. Unpredictability remains the largest obstacle in effectively integrating wind energy into SPP's generating mix. As wind speeds change, utilities must instantaneously switch to and from other generating resources to compensate for this variability. Increasing the capability to forecast wind's time, location, and speed will significantly enhance operators' ability to reliably manage the grid. In 2011, SPP implemented a new wind forecasting tool to generate five-minute, hourly, and day-ahead projections.

The Acadiana Load Pocket located in southern Louisiana did not experience any reliability issues in the winter of 2011 or the summer of 2012. The addition of Cleco's 230 kV line from Roark to Sellers Road and Entergy's Sellers Road to Meaux 230 kV line prior to the summer of 2011, along with the energizing of the Segura 230 kV line in fall 2011, alleviated a portion of the most limiting elements. The 230 kV line from Labbe to Bonin was energized in February 2012, and two other 230 kV lines from Wells to Labbe and Labbe to Sellers Rd. were energized on June 28, 2012. The completion of these projects should further alleviate transmission congestion in this area and the planned Acadiana Load Pocket projects have been completed.

SPP RTO conducted a reliability assessment based on members' plans for compliance with the CSAPR and MATS in April 2012. As noted above, SPP RTO does not anticipate that either of these EPA regulations will have a reliability impact in the SPP RTO area during the 2012/2013 winter assessment period. SPP Staff are currently reviewing outage requests submitted through 2016 to determine if a large number of outages or retirements will cause any reliability concerns. The results of that study are expected this year.[89]

SPP RTO reviews potential fuel supply limitations by consulting with its generation-owning and generation-controlling members via electronic communications. There are no known infrastructure issues which should impact fuel deliverability, as the SPP Region is blanketed by major pipelines and railroads that provide access to an adequate fuel supply. SPP Criteria require coal and natural gas-fired power plants, which make up approximately 37 percent and 45 percent of total generation respectively, to maintain sufficient quantities of standby fuel on site in case of deliverability issues.[90]

[89] Results in October are preliminary.
[90] SPP Criteria 2.4.2

WECC

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**131,070**
Load-Modifying Demand Response	1,920
Net Internal Demand	**129,150**

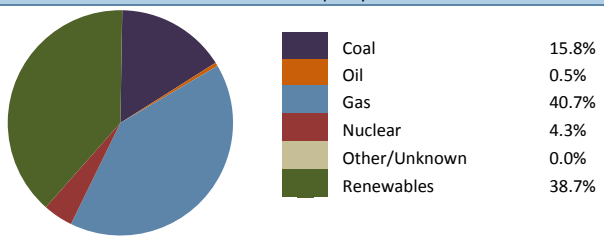
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	129,485
Actual Demand	126,337

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	182,551
Anticipated Resources	**182,551**
Anticipated Reserve Margin (%)	**41.35%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**182,551**
Prospective Reserve Margin (%)	**41.35%**
NERC Reference Margin Level (%)	**14.60%**

Assessment Area Capacity Mix



Subregional Considerations

The WECC Assessment Area is divided into four subregions for NERC's seasonal assessments: Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CA/MX). These subregions are used for two reasons. First, the subregions are structured around Reserve Sharing Groups. These groups have similar demand patterns and have similar operating practices. Second, the WECC Reliability Coordinator (RC) collects actual demand data from the Reserve Sharing groups. Creating the seasonal assessments using the same footprint allows for after-the-fact comparison between demand forecasts and actual demand.

Planning Reserve Margins

Reserve Margins for the summer peaking WECC Assessment Area are projected to remain above the NERC Reference Reserve Margin Level during the winter season. Alberta, Canada has the lowest projected Anticipated Capacity Resources (ACR) reserve margin for the upcoming winter, at 12.2 percent. However, that ACR exceeds the Reference Reserve Margin of 11.7 percent and is roughly double the operating reserve requirement.

The reserve margin adequacy is largely due to the construction of power plants in anticipation of a load growth that was interrupted by the recent recession and slow economic recovery. It should be noted that abnormal weather conditions would result in different reserve margins and severe adverse weather conditions or unexpected equipment failure could result in localized power supply or delivery limitations.

Demand

The aggregate WECC 2012/2013 winter total coincident peak demand is forecast to be 131,070 MW and is projected to occur in December. The forecast is 3.7 percent above last winter's actual peak demand of 126,337 MW, which was established under generally normal to slightly-warmer-than-normal temperatures with poor economic conditions in the region. The 2012/2013 winter coincident peak demand forecast is 1.2 percent above last winter's forecast coincident peak demand of 129,485 MW. The nominal increase in the prior year to current year winter peak demand forecasts largely reflects an expectation of nominal economic growth.

Demand-Side Management

Demand-side management programs are designed to reduce peak demands and conserve energy. These programs incorporate both active and passive actions. Passive programs generally focus on activities that reduce annual energy

consumption while simultaneously reducing peak demand. Entities within WECC have reported peak demand reductions associated with such programs at 393 MW.

Active DSM programs offered by Load-Serving Entities (LSE) vary widely. The 2012/2013 winter demand forecast includes 79 MW of Direct Control Load Management (DCLM), 1,427 MW of contractually interruptible demand, zero MW of critical-peak-pricing with control, and 414 MW of load as a capacity resource. As a percent of Total Internal Demand, total demand response could reduce peak demand by 1.5 percent. DCLM programs largely focus on air conditioner cycling programs while interruptible demand programs focus primarily on large water pumping operations and large industrial operations such as mining.

State and other regulatory drivers have led to nominal increases in DSM program penetration within the WECC subregions and, within some established market structures, DSM has been established as an ancillary service.

Generation

WECC's Western Interconnection modeling data report the available Existing-Certain capacity at 181,245 MW, Existing-Other capacity at zero megawatts, and Existing-Inoperable capability at 6,051 MW. The modeled Existing-Certain capabilities by fuel type are:

- 28.8 percent hydroelectric;
- 16.6 percent coal;
- 40.6 percent natural gas;
- 4.3 percent nuclear; and
- 9.7 percent all other fuel types.

It is expected that coal and natural gas will be readily available throughout the winter period. As is normally the case, hydroelectric generation may be somewhat limited but this limitation is adequately reflected in the reported hydro derates. Capacity changes since year-end 2011 are classified as Future-Planned. The net Future-Planned capacity changes total 2,917 MW from the start of the year through the end of September.

Capacity additions from the end of September through the end of the winter period are also classified as Future-Planned. Those capacity changes total 1,787 MW.

WECC's modeling for the winter assessment peak period gives a total renewables expected capacity of 60,497 MW from a nameplate capacity of 81,727 MW.[91]

Capacity Transactions

The WECC Region does not rely on imports from outside the Region when calculating peak demand reliability margins, nor does WECC rely on outside assistance or external resources for emergency imports, and does not model exports to areas outside of WECC.

Transmission

No project delays or temporary service outages of transmission facilities have been reported that will adversely impact reliability during the 2012/2013 winter season. In addition, no specific projects have been reported that are needed to maintain reliability.

Operations

WECC staff does not perform any special operating studies concerning extreme weather or drought conditions for the seasonal assessments. However, these studies are performed by the individual LSEs and BAs within WECC.

[91] The renewable expected capacity modeling for wind resources uses generation curves created from three years of one-hour interval wind speed data. Expected capacity modeling for solar resources uses generation curves created from two years of insolation data. Hydro generation is dispatched economically, limited by expected annual energy generated during an adverse hydro year. Biomass and geothermal capacities are based on nominal plant ratings.

The highly variable nature of wind and solar resources complicates daily power grid operation, often more significantly during off-peak periods than during on-peak periods. Operational procedures, such as implementing and testing resource curtailment capability and increased reserve requirements, are expected to address the wind and solar generation variability issues.

A significant portion of the demand response is related to seasonally-impacted loads such as residential air conditioning and irrigation system pumps. Hence, available demand response is less during the winter season than during the summer season. Due to the reduced winter season demand and increased margins, in most areas compared to the summer season, demand response dependability is of little concern.

Power plants operate under numerous environmental and other regulatory restrictions, including emission, water level, and water temperature limitations. The cumulative magnitude of the restrictions, although not quantified, is incorporated into the expected on-peak capabilities used for this assessment and the restrictions are not expected to adversely affect reliability during the winter season.

Vulnerability Assessment

The west experienced a relatively warm and dry summer, resulting in reservoir draw downs in some areas. The Colorado River basin is in essentially the twelfth year of a persistent drought.[92] It is expected that the reduced river flows will result in increased thermal-based energy generation but will not significantly affect the ability to meet peak demand. The margin information presented in this assessment reflects an assumed adverse hydroelectric generation condition.

The CISO has reported a San Francisco Bay area Special Protection System (SPS) as a temporary solution to a current local area congestion issue. Also, the CISO has reported three SPSs that are temporary bulk power transmission facility solutions related to new variable resource additions.

WECC entities have not reported any pending environmental regulations that have an impact on their upcoming season planning and have not included potential environmental regulation effects in their upcoming season plans.

Area entities report that they routinely coordinate their fuel supply needs with fuel and transportation suppliers on several levels. For example, significant portions of the coal supply are acquired under long-term contracts with mines and transportation providers and the power plants generally have significant on-site coal storage facilities. These long-term arrangements are largely unaffected by short-term conditions so seasonal planning coordination beyond pre-established parameters is minimal.

On the other hand, natural gas deliveries are often scheduled on a very short-term basis, e.g. daily. This short-term acquisition process, coupled with generally very limited storage located near power plants and gas pipeline pressure limitations, may lead to supply interruptions should other conditions, such as an unexpected cold snap or colder-than-expected temperatures occur. These temperature-driven supply interruption events are generally localized and are not expected to significantly affect reliability this winter.

[92] Upper Colorado River Basin Region: http://www.drought.gov/drought/regional-programs/ucrb/ucrb-home

Appendix I: Estimated Demand, Resources, and Reserve Margins

Demand

NERC uses the following terms to categorize on-peak electricity demand:

- **Total Internal Demand**: The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all non-dispatchable Demand Response Programs. This value is used in the Planning Reserve Margin calculation.
- **Net Internal Demand**: Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load.

Capacity Resources

NERC uses the following terms to categorize capacity resources and transactions in seasonal assessments:

Existing Capacity Resources

- **Existing-Certain**: Existing generation resources available to operate and deliver power within or into the assessment area (or Region) during the period of assessment.
- **Existing-Other**: Existing generation resources that may be available to operate and deliver power within or into the assessment area (or Region) during the period of assessment, but may be curtailed or interrupted at any time for various reasons.
- **Existing, but Inoperable**: Existing portion of generation resources that are out of service and cannot be brought back into service to serve load during the period assessment.

Existing Capacity Resources

- **Future-Planned**: Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of assessment.
- **Future-Other**: Future generating resources that do not qualify in Future-Planned and are not included in the Conceptual category.

Capacity Transactions

- Net Firm and Expected Transactions: Firm and Expected Imports, minus Firm and Expected Exports; including all Firm contracts with a reasonable expectation to be implemented.

Reserve Margins

Reserve Margins are capacity-based metrics and do not provide a comprehensive assessment of performance in energy-limited systems (*e.g.,* hydro capacity with limited water resources or systems with significant variable generation). Each capacity resource category (identified and explained in the previous section) is also used to calculate each different planning Reserve Margin.

Planning Reserve Margins for each assessment area are compared to the NERC Reference Margin Level, which is assigned for each NERC assessment area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined Reference Reserve Margin, NERC has applied a 10 or 15 percent Reference Reserve Margin for predominately hydro or thermal systems, respectively.

The NERC Reference Reserve Margin Level serves as a basis for determining whether more resources (*e.g.,* generation, Demand-Side Management, transfers) may be needed within that Region/subregion.

Note 1: Demand and Supply forecasts were reported between February and August, 2011—depending on the assessment area.

Note 2: Values for both Total Internal Demand and Net Internal Demand for each assessment area represent on-peak projections.

Note 3: The WECC-US peak demands or resources do not necessarily equal the sums of the non-coincident WECC-US subregional peak demands or resources because of subregional monthly peak demand diversity. Similarly, the Western Interconnection peak demands or resources do not necessarily equal the sums of the non-coincident WECC-U.S., Canada, and México peak demands or resources. In addition, the subregional resource numbers include use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking portions of the Western Interconnection.

Appendix II: Abbreviations Used in this Report

Abbreviation	Term	Abbreviation	Term
A/C	Air Conditioning	IA	Interchange Authority
AEP	American Electric Power	ICAP	Installed Capacity
AFC	Available Flowgate Capability	ICR	Installed Capacity Requirement
ASM	Ancillary Services Market	IESO	Independent Electric System Operator (in Ontario)
ATCLLC	American Transmission Company	IOU	Investor Owned Utility
ATR	AREA Transmission Review (of NYISO)	IPSI	Integrated Power System Plan
AWEA	American Wind Energy Association	IRM	Installed Reserve Margin
BA	Balancing Authorities	IROL	Interconnection Reliability Operating Limit
BASN	Basin (subregion of WECC)	IRP	Integrated Resource Plan
BCF	Billion cubic feet	ISO	Independent System Operator
BCF/d	Billion cubic feet per day	ISO-NE	New England Independent System Operator
CALN	California-North (subregion of WECC)	kV	Kilovolts (one thousand volts)
CALS	California-South (subregion of WECC)	LaaRs	Loads acting as a Resource
CANW	WECC-Canada (subregion of WECC)	LCR	Locational Installed Capacity Requirements
CFL	Compact Fluorescent Light	LDC	Liquidated Damage Contract
CMPA	California-Mexico Power Area	LFU	Load Forecast Uncertainty
COI	California-Oregon Intertie	LNG	Liquefied Natural Gas
COS	Coordinated Outage (transmission) System	LOLE	Loss of Load Expectation
CPUC	California Public Utilities Commission	LOLP	Loss Of Load Probability
CRO	Contingency Reserve Obligation	LOOP	Loss of off-site power
CRPP	Comprehensive Reliability Planning Process (of NYISO)	LRP	Long Range Plan
DADRP	Day-Ahead Demand Response Program	LSE	Load-serving Entities
dc	Direct Current	LTRA	Long-Term Reliability Assessment
DCLM	Direct Controlled Load Management	LTSG	Long-term Study Group
DFW	Dallas/Fort Worth	MAAC	Mid-Atlantic Area Council
DLC	Direct Load Control	Maf	Million acre-feet
DOE	U.S. Department of Energy	MAIN	Mid-America Interconnected Network, Inc.
DSG	Dynamics Study Group	MAPP	Mid-Continent Area Power Pool
DSI	Direct-served Industry	MCRSG	Midwest Contingency Reserve Sharing Group
DSM	Demand-Side Management	MEXW	WECC-Mexico (subregion of WECC)
DSW	Desert Southwest (subregion of WECC)	MISO	Midwest Independent Transmission System Operator
DVAR	D-VAR® reactive power compensation system	MPRP	Maine Power Reliability Program
EDRP	Emergency Demand Response Program	MRO	Midwest Reliability Organization
EE	Energy Efficiency	MVA	MegaVolt Ampere
EEA	Energy Emergency Alert	MVAr	MegaVolt Ampere reactive
EECP	Emergency Electric Curtailment Plan	MW	Megawatts (millions of watts)
EIA	Energy Information Agency (U.S. Department of Energy)	MWEX	Minnesota Wisconsin Export
EILS	Emergency Interruptible Load Service (of ERCOT)	NB	New Brunswick
EISA	Energy Independence and Security Act of 2007 (USA)	NBSO	New Brunswick System Operator
ELCC	Effective Load-carrying Capability	NDEX	North Dakota Export Stability Interface
EMTP	Electromagnetic Transient Program	NEEWS	New England East West Solution
ENS	Energy Not Served	NERC	North American Electric Reliability Corporation
EOP	Emergency Operating Procedure	NIETC	National Interest Electric Transmission Corridor
ERAG	Eastern Interconnection Reliability Assessment Group	NOPSG	Northwest Operation and Planning Study Group
ERCOT	Electric Reliability Council of Texas	NORW	Northwest (subregion of WECC)
ERO	Electric Reliability Organization	NPCC	Northeast Power Coordinating Council
FCITC	First Contingency Incremental Transfer Capability	NPDES	National Pollutant Discharge Elimination System
FCM	Forward Capacity Market	NPPD	Nebraska Public Power District
FERC	U.S. Federal Energy Regulatory Commission	NSPI	Nova Scotia Power Inc.
FP	*Future-Planned*	NTSG	Near-term Study Group
FO	*Future-Other*	NWPP	Northwest Power Pool Area (subregion of WECC)
FRCC	Florida Reliability Coordinating Council	NYISO	New York Independent System Operator
GADS	Generating Availability Data System	NYPA	New York Planning Authority
GDP	Gross Domestic Product	NYRSC	New York State Reliability Council, LLC
GGGS	Gerald Gentleman Station Stability	OASIS	Open Access Same Time Information Service
GHG	Greenhouse Gas	OATT	Open Access Transmission Tariff
GRSP	Generation Reserve Sharing Pool (of MAPP)	OP	Operating Procedure
GTA	Greater Toronto Area	OPA	Ontario Power Authority
GWh	Gigawatt hours	OPPD	Omaha Public Power District
HDD	Heating Degree Days	ORWG	Operating Reliability Working Group
HVac	Heating, Ventilating, and Air Conditioning	OTC	Operating Transfer Capability

Abbreviation	Term	Abbreviation	Term
OVEC	Ohio Valley Electric Corporation	SCD	Security Constrained Dispatch
PA	Planning Authority	SCDWG	Short Circuit Database Working Group
PACE	PacifiCorp East	SCEC	State Capacity Emergency Coordinator (of FRCC)
PAR	Phase Angle Regulators	SCR	Special Case Resources
PC	NERC Planning Committee	SEMA	Southeastern Massachusetts
PCAP	Pre-Contingency Action Plans	SEPA	State Environmental Protection Administration
PCC	Planning Coordination Committee (of WECC)	SERC	SERC Reliability Corporation
PJM	PJM Interconnection	SMUD	Sacramento Municipal Utility District
PRB	Powder River Basin	SOL	System Operating Limits
PRC	Public Regulation Commission	SPP	Southwest Power Pool
PRSG	Planned Reserve Sharing Group	SPS	Special Protection System
PSA	Power Supply Assessment	SPS	Special Protection Schemes
PUCN	Public Utilities Commission of Nevada	SRIS	System Reliability Impact Studies
QSE	Qualified Scheduling Entities	SRWG	System Review Working Group
RA	Resource Adequacy	STATCOM	Static Synchronous Compensator
RAP	Remedial Action Plan	STEP	SPP Transmission Expansion Plan
RAR	Resource Adequacy Requirement	SVC	Static VAr Compensation
RAS	Reliability Assessment Subcommittee	TCF	Trillion Cubic Feet
RC	Reliability Coordinator	TFCP	Task Force on Coordination of Planning
RCC	Reliability Coordinating Committee	THI	Temperature Humidity Index
RFC	ReliabilityFirst Corporation	TIC	Total Import Capability
RFP	Request For Proposal	TID	Total Internal Demand
RGGI	Regional Greenhouse Gas Initiative	TLR	Transmission Loading Relief
RIS	Resource Issues Subcommittee	TOP	Transmission Operator
RMR	Reliability Must Run	TPL	Transmission Planning
RMRG	Rocky Mountain Reserve Group	TRE	Texas Regional Entity
ROCK	Rockies (subregion of WECC)	TRM	Transmission Reliability Margins
RP	Reliability Planner	TS	Transformer Station
RPM	Reliability Pricing Mode	TSP	Transmission Service Provider
RRS	Reliability Review Subcommittee	TSS	Technical Studies Subcommittee
RSG	Reserve Sharing Group	TVA	Tennessee Valley Authority
RTEP	Regional Transmission Expansion Plan (for PJM)	UFLS	Under Frequency Load Shedding Schemes
RTO	Regional Transmission Organization	UVLS	Under Voltage Load-Shedding
RTP	Real-time Pricing	VAr	Voltampere reactive
RTWG	Renewable Technologies Working Group	VACAR	Virginia and Carolinas (subregion of SERC)
SA	Security Analysis	VSAT	Voltage Stability Assessment Tool
SasKPower	Saskatchewan Power Corp.	WALC	Western Area Lower Colorado
SCADA	Supervisory Control and Data Acquisition	WECC	Western Electricity Coordinating Council
SCC	Seasonal Claimed Capability	WTHI	Weighted Temperature-Humidity Index
		WUMS	Wisconsin-Upper Michigan Systems

Appendix III: Reliability Assessment Subcommittee Roster

Reliability Assessment Subcommittee Members

Name	Position	Represents	Job Title	Organization
Vince Ordax	Chair	FRCC*	Manager of Planning	FRCC
Curtis Crews	Vice Chair	TRE*	Lead Reliability Assessment Engineer	TRE
Justin Michlig	Member	MRO	Transmission Planning Specialty Engineer	Xcel
William B. Kunkel	Member	MRO*	Senior Engineer	MRO
John Lawhorn	Member	MRO	Senior Director, Regulatory and Economic Studies	Midwest ISO, Inc.
Madhuri Kandukuri	Member	MRO	Senior Engineer , Regulatory and Economic Studies	Midwest ISO, Inc.
Josh Collins	Member	MRO	Engineer I	Midwest ISO, Inc.
Bagen Bagen	Member	MRO	Principal Planning Engineer	Manitoba Hydro
Salva R. Andiappan	Member	MRO	Manager- Modeling and Reliability Assessments	MRO
Rao Konidena	Member	MRO	Manager, Resource Forecasting	Midwest ISO, Inc.
Bagen Bagen	Member	MRO	Principal Planning Engineer	Manitoba Hydro
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John G Mosier Jr.	Member	NPCC*	Assistant Vice President of System Operations	NPCC
Paul A. Roman	Member	NPCC	Manager, Operations Planning	NPCC
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Joaquin (Jack) M. Alvarez	Member	NPCC	Senior Engineer	NPCC
Kevan L. Jefferies	Member	NPCC	Manager - Market Forecasts and Modeling	Ontario Power Generation Inc.
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Tim Fryfogle	Member	RFC*	Associate Engineer	RFC
Mark J.Kuras	Member	RFC	Senior Lead Engineer	PJM
Bob Mariotti	Member	RFC	Supervisor - Short Term Forecasting	DTE Energy
Glenn P Catenacci	Member	RFC	Principal Staff Engineer	PSE&G
Esam A.F. Khadr	Member	RFC	Director Electric Delivery Planning	PSE&G
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Maria Haney	Member	SERC*	Reliability Assessment Engineer	SERC
Hubert C. Young	Member	SERC	Senior Manager, Capacity Planning	TVA
K. R. Chakravarthi	Member	SERC	Manager, Interconnection and Special Studies	Southern Company Services, Inc.
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David Kelley	Member	SPP RE*	Manager, Interregional Coordination	SPP Inc.
Deborah K. Currie	Member	SPP RE*	Lead Engineer	SPP RE
James Useldinger	Member	SPP RE	Manager, T&D System Operations	KCP&L
Warren Lasher	Member	TRE	Manager, System Assessment	ERCOT
Layne Brown	Member	WECC*	Manager, Reliability Assessments	WECC
Tina G. Ko	Member	WECC	Manager, Resources & Loads Analysis	BPA
James Leigh-Kendall	Member	WECC	Manager, Reliability Compliance and Coordination	SMUD
Jerry D. Rust	Observer	N/A	President	NPPC
Sedina Eric	Observer	GOV	Electrical Engineer	FERC
David J. Burnham	Observer	GOV	Electrical Engineer	FERC
Patricia Hoffman	Observer	GOV	Assistant Secretary	DOE
Maria A. Hanley	Observer	GOV	Energy Analyst	DOE-NETL
Erik Paul Shuster	Observer	GOV	Engineer	DOE
Peter Balash	Observer	GOV	Senior Economist	DOE
C. Richard Bozek	Observer	Trades	Director, Environmental Policy	EEI
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*Regional Entity Representative

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RIISC 2012

Reliability Issues Information-Sharing Conference

A Discussion of Reliability Risks and Emerging Issues

November 28, 2012 9:00am – 4:00pm | Washington, DC

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Welcome

Reliability Issues Information-Sharing Conference

A Discussion of Reliability Risks and Emerging Issues

Gerry Cauley
President and CEO, NERC

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Report on the RISC

Reliability Issues Steering Committee

Chris Schwab
Vice President, Regulatory Compliance and Chief Risk Officer
Dominion Resources Services, Inc.; Chair of the RISC

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Panel 1

Engineering and Planning Issues

Protection System Misoperations -Joe Spencer, SERC

Protection System Design - Jonathan Sykes, PG&E

Generation Modeling Tools and Accuracy - Dr. John Undrill

Transmission Modeling Tools and Accuracy - Rob O'Keefe, AEP

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Protection System Misoperations

Joe Spencer, SERC; Chair, ERO-RAPA

November 28, 2012

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Misoperations Reporting Overview

Background

- Protection Systems Misoperations (misops) identified as #1 NERC reliability issue (2010)
- Data collected under NERC standards PRC-003 and 004
- Regional differences made ERO trending difficult
- Near term effort - align regional misops reporting procedures
- Misops template finalized/approved via regional procedures
- Long term solution – Use NERC wide standard development (project 2010-05.1)
- Mandatory regional reporting in 2nd qtr 2011.
- Six quarters of NERC wide reporting now reported

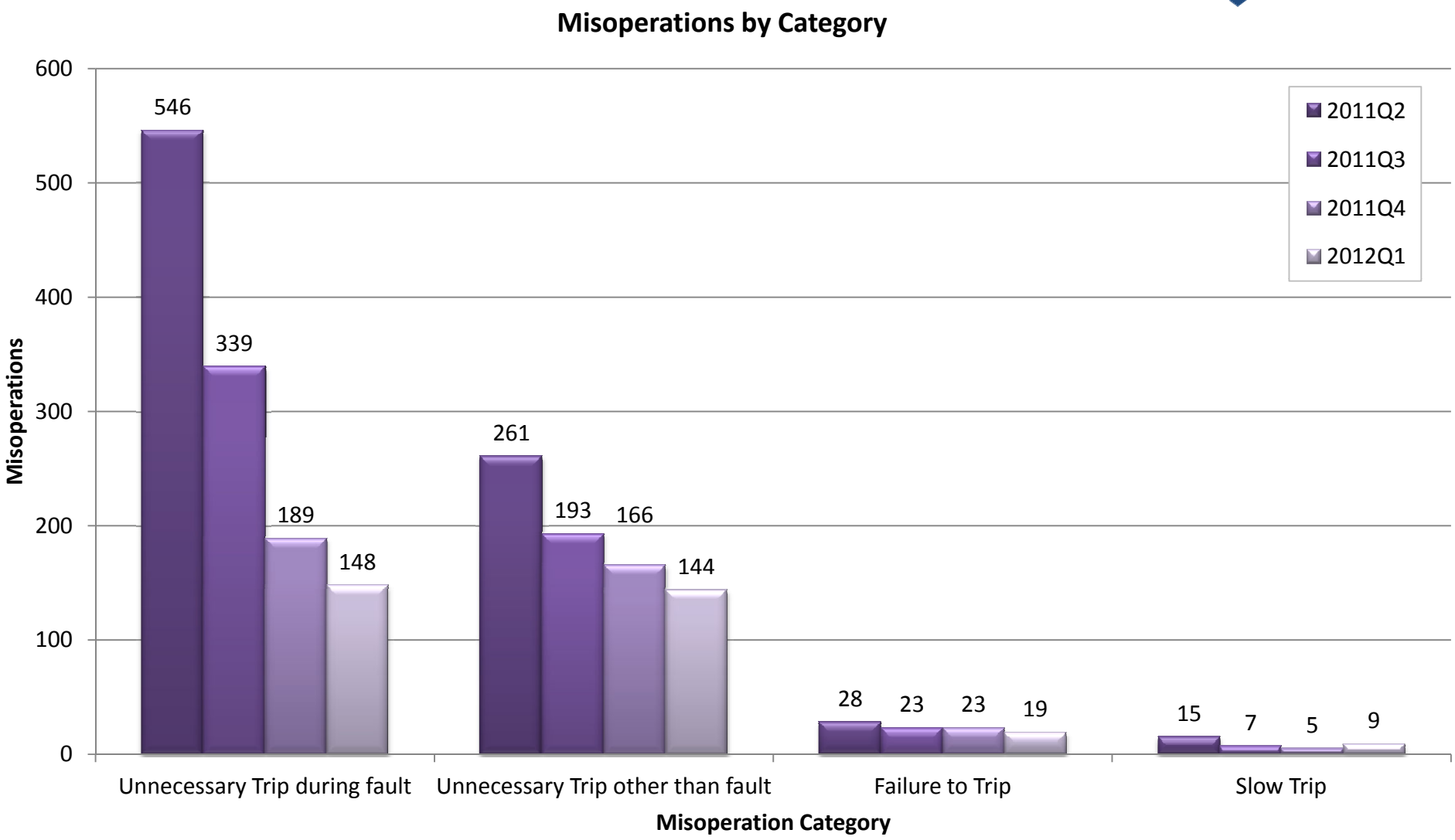
Misoperations Reporting Overview

Recent Efforts

- SPCS recommended collection of "total operations" for metrics (ALR 4-1)
- PS misops task force (PSMTF) established by PC to analyze past/current data
  - Recent focus – 2nd qtr 2011 thru 1st qtr 2012 – review of top three cause codes
  - Past focus – Pre 2011 – Consistent format proposed – review of data available from six regions.
  - Report targeted for early 2013
- ERO-RAPA and SPCS in communication with the Project 2010-05.1 SDT

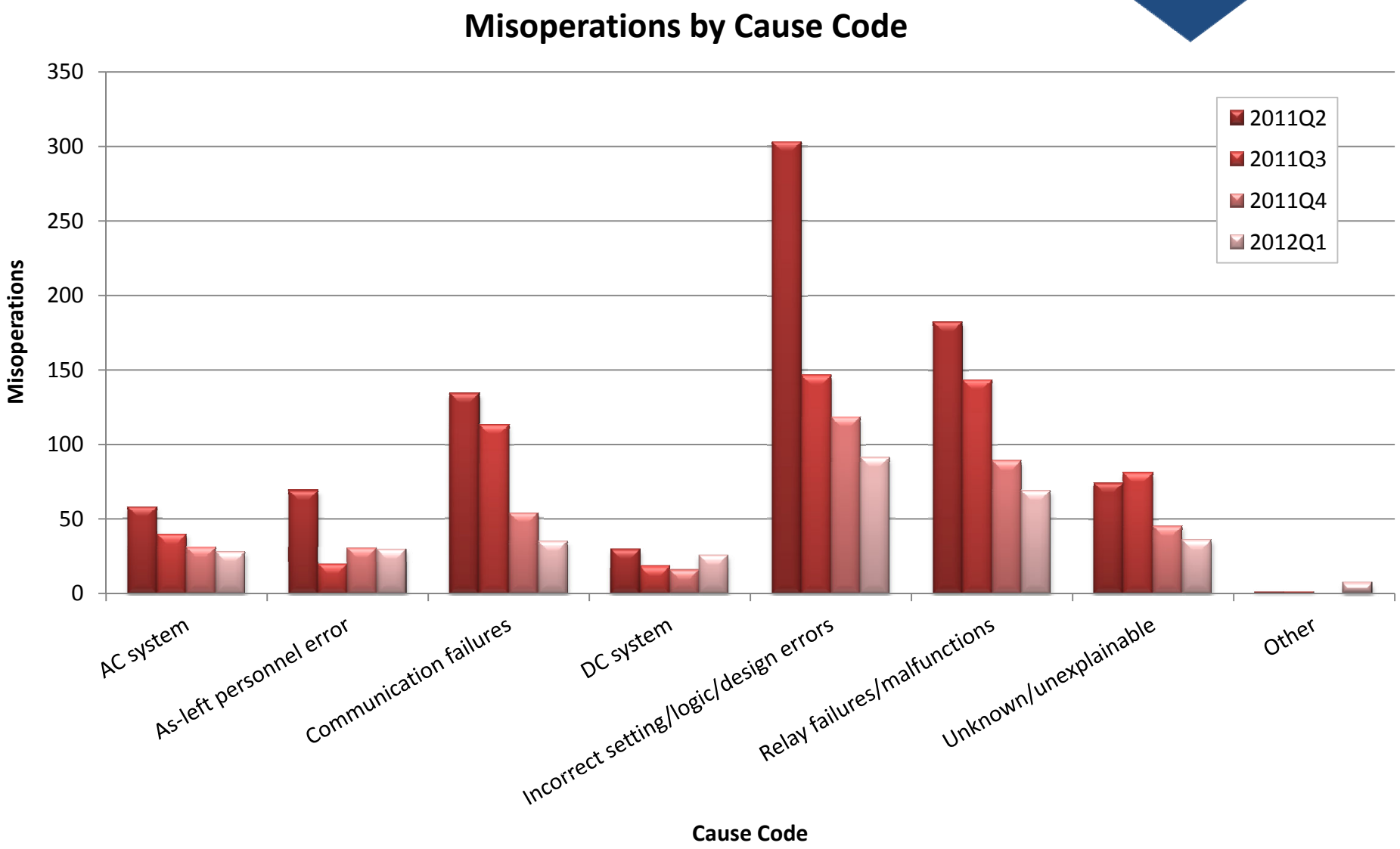
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Misops Categories



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Misops Causes

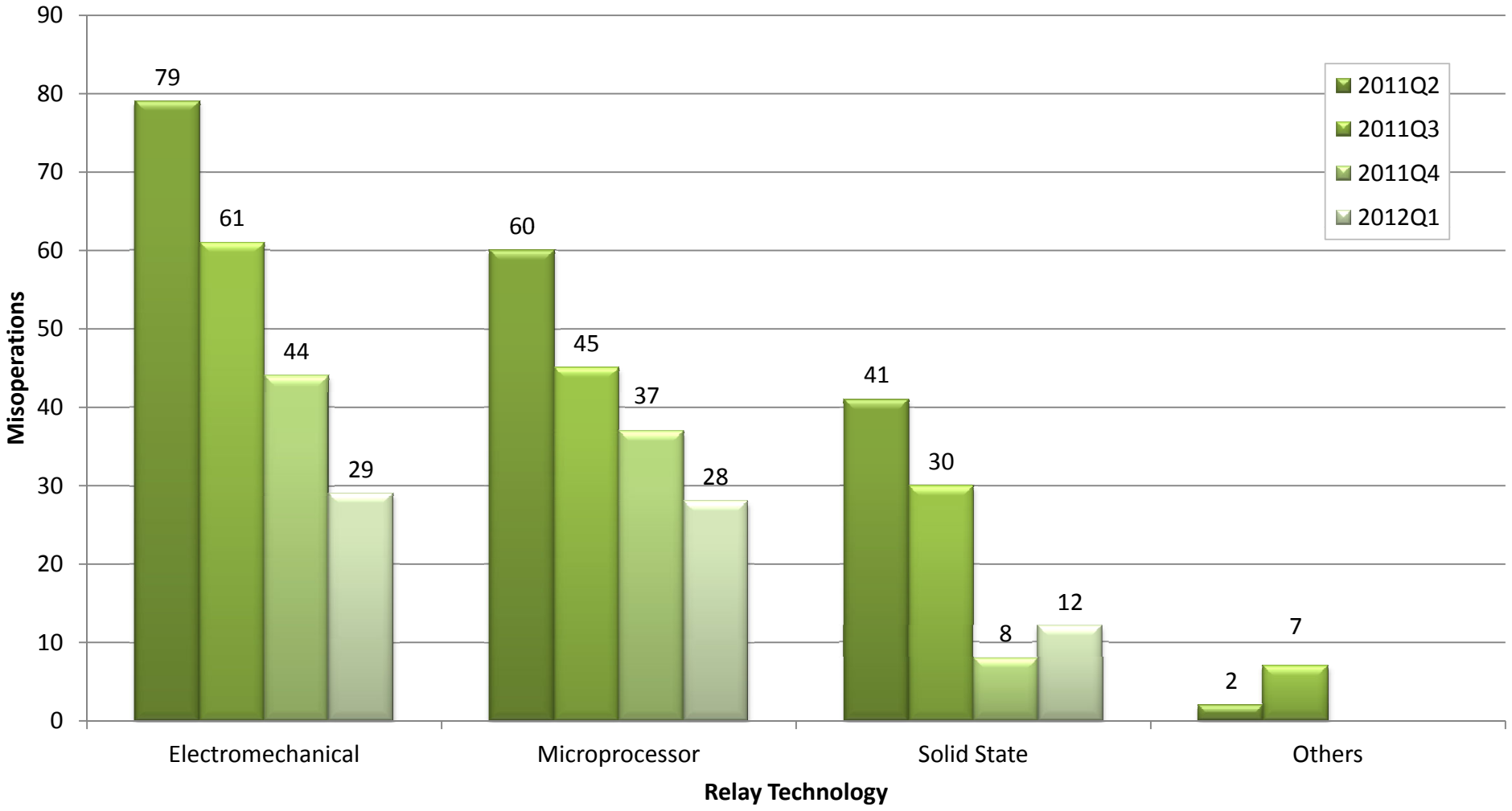


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Relay Technology (Failures / Malfunctions)

Misoperations by Relay Technology in 2011Q4

(Only Relay Failures/Malfunctions Cause Code)



Misoperations Reporting Overview

What's the Reliability Issue?

- Protection systems fundamentally for isolating faults and protecting equipment
- 95% of misops are unnecessary trips
- Electromechanical relays being replaced with microprocessor based
- Microprocessor based relays – capable but sophisticated
- Top cause codes
  - Incorrect settings and design errors – microprocessor based
  - Relay failures - electromechanical based
- Available expertise for specifying schemes and setting relays
- Obsolescence – life expectancy of new relays
- Updating relays – opportunity for incorporating errors?

What's the Reliability Issue (continued)?

- Process/procedures for procuring, specifying and setting relays
- Balancing dependability with security
  - Is it active when it should be (dependability)
  - Is it inactive when it should be (security)
- PRC-023-2 is driving fine-tuning of relays to remove "conservatism"
  - How much conservatism is there?
  - What's the tipping point?
  - What are implications of "tipping"?
  - Implication of adding layers of complexity?

Moving Forward

- More clear
  - Primarily (not exclusively) a human performance issue
  - Need for expertise and process
    - Identify components of program excellence
    - Identify and promote programs of excellence
    - Develop and roll-out focused training
    - Encourage development of P&C engineers/technicians

Moving Forward (continued)

- Less clear
  - Managing specification complexity
    - Balancing intentions of current standards (PRC-004, PRC-023, TPL's and others)
    - Reaction to failures
  - Understanding the implications of reduced misops
    - Where's the tipping point? implications of getting there?
    - Learning from other industries (airline and nuclear)
  - Expectations of relay vendors
  - Value of standardization

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Protection System Design

Jonathan Sykes, PG&E

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Problem Statement

- Protection Systems have single points of failure that if not mitigated by design or studies can cause the following issues:
  - Adverse impact to system reliability
  - Loss of equipment
  - Loss of customers

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Protection Systems

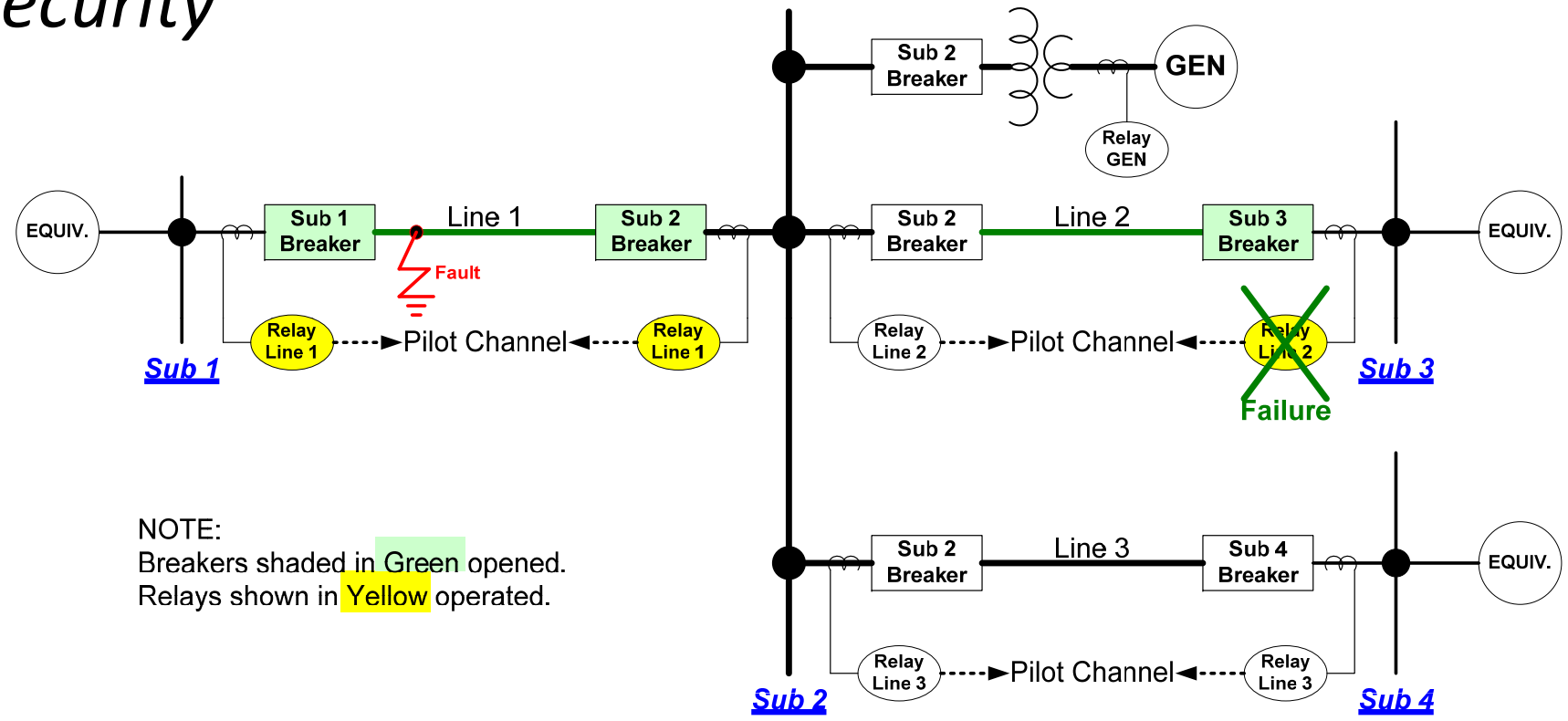
Protection Systems are applied and designed to protect Elements of the power grid by detecting faults and other perturbations and isolating the disturbance as quickly as possible from the rest of the grid.

Design Concepts

- Dependability (must always operate)
- Security (no false operations)
- Availability (for testing, failures, etc.)

Failure Modes

Security



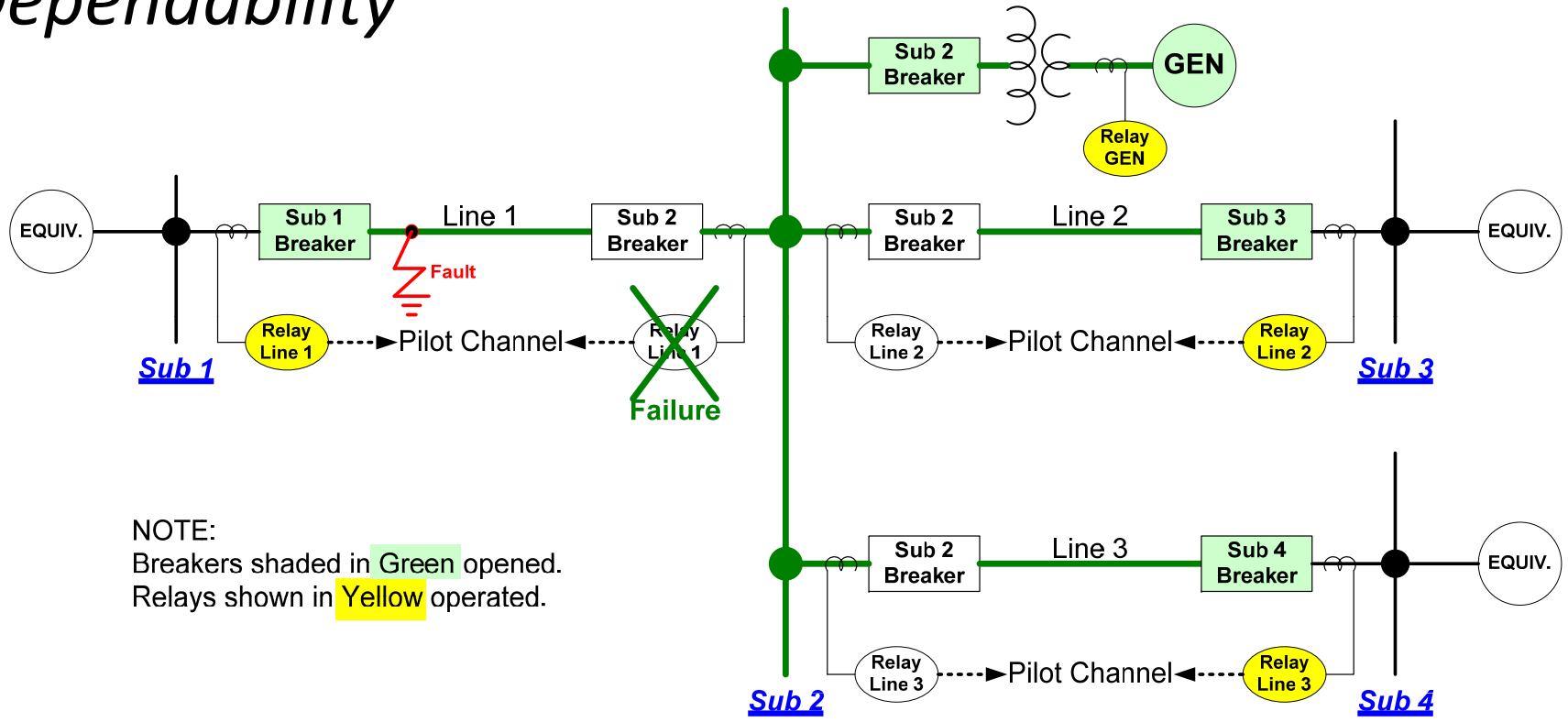
Security

Is the degree of certainty that Protection Systems will not operate incorrectly.

Security Type failures and misoperations generally do not have significant impact to the electric system.

Failure Modes

Dependability



Dependability

Is the degree of certainty that Protection Systems will operate correctly.

Dependability Type failures and misoperations can have significant impact to the electric system.

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Outages

Single Point of Failure has been contributory in the following outages:

- Westwing Disturbance – June 14, 2004
  - Single auxiliary relay on 230kV line failed, resulting in the loss of approximately 5,000MW of generation and numerous 500kV and 230kV lines.
- Broad River Disturbance – Aug. 25, 2007
  - Single lockout relay used to trip and initiate breaker fail timers on a GSU failed, resulting in the loss of 871MW of generation and numerous 230kV lines
- PacifiCorp East Disturbance – Feb. 14, 2008
  - Single lockout relay used to trip and initiate breaker fail timers on a GSU failed, resulting in the loss of 2,803MW of generation and numerous 345kV lines

Dependability

Protection Systems must achieve a level of dependability to prevent a disturbance from damaging equipment or causing a wide spread outage.

Design Considerations

- Clearing times (Normal and time delayed)
- Redundancy/duplicate/multiple systems
- Local Backup (selectivity and time considerations)
- Remote Backup (selectivity and time considerations)

Existing Resources

NERC Standards

- TPL (old and new)
- PRC (coordination, misoperation, maintenance)

Regional Standards

- WECC, NPCC and others

Company Standards

- To protect safety, high value assets, and reliability

Industry Standards, Guides, and Papers

- IEC, IEEE, NERC, WECC, Manufacturers and others

Definition Protection System

Protection System is a collective term which defines the equipment that detects, locates, and isolates the fault or abnormal condition from the power system.

NERC Protection System (Component Based)

- **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 station batteries, battery chargers, and non-battery-based dc supply), and
- **Control circuitry** associated with protective functions through the trip coil(s) of the circuit breaker or other interrupting devices

Definition Redundancy

NERC SPCS Technical Paper (2009 - 60 Pages)

Redundancy means that two or more functionally equivalent Protection Systems are used to protect each electric system element. Redundancy can be achieved in a variety of ways depending on the performance required and the infrastructure available.

1. No Common Single Points of Failure
2. Two Local Systems (High Speed)
3. One Local and One Remote (Low Speed)

IEEE PSRC WG I19 Paper (2011 - 60 pages)

Conclusion - There are many correct methods to accomplish protection system redundancy. ... Each utility…will have preferred method or methods of protection. … (stakeholders and industry changes in equipment etc.) contribute to the various methods used to achieve an acceptable level of redundancy, reliability, dependability, and security. The protection system redundancy goal should always be to promote a reliable electric system that is practical, robust, flexible, and safe to operate.

NERC SPCS Paper

Methodology to Reliability of Protection System

- Determine Redundancy of the Protection Systems
- Ascertain the Performance of the Protection Systems
- Compare Protection Systems performance with electric system performance requirements in the TPL standards
- Mitigate all performance shortfalls

Active Efforts

NERC/Industry Response to FERC Order 754

- 1600 Data Request – Owners will provide data per document "Order 754 Single Point of Failure"
  - Bus Selection (Iterative study process, 3 phase fault)
  - Protection System Performance
    (Redundancy or clearing times for SPOF)
  - Documentation and Submittal
- Request for Interpretation 2012-INT-02 (TPL-003 and -004)
  - Clarification of how to study "stuck breaker" or "protection system failure" contingency, or the most severe of these (R 1.3.1)
  - Clarification of the study of single point of failure of a protection system components (Table 1, Footnote (e))

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Next Steps

- Complete the 1600 Data Request for SPOF
- Complete the Request for Interpretation (2012-INT-02)
- Monitor the Protection System Misoperations Data
- Provide timely information to the industry about major events or trends through Lessons Learned and NERC Alerts
- Leverage Technical Subcommittees (SPCS, SAMS) and Industry Organizations (IEEE, IEC, EPRI, Transmission Forum, etc.)

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Generation Modeling Tools and Accuracy

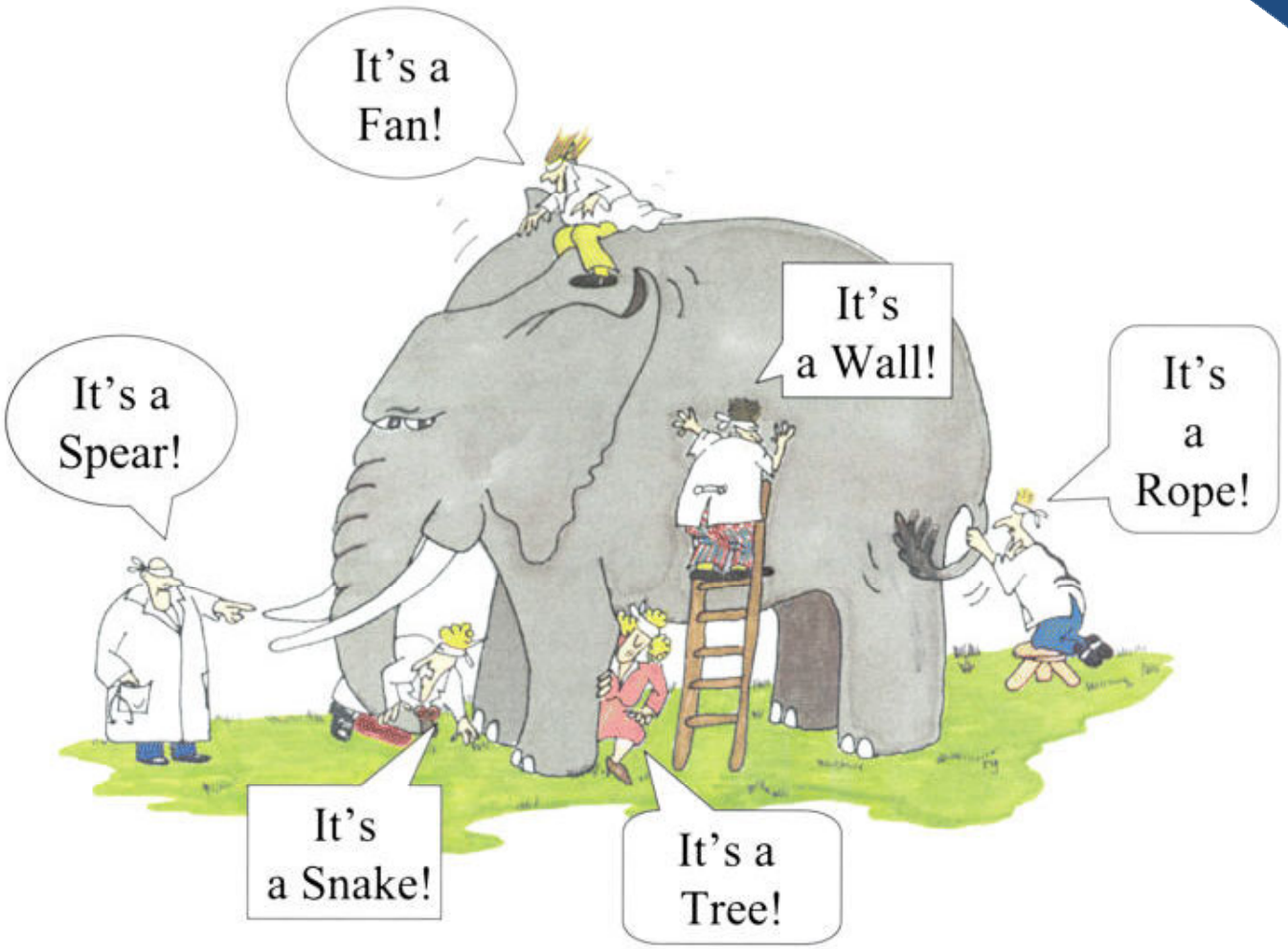
Dr. John Undrill

November 28, 2012

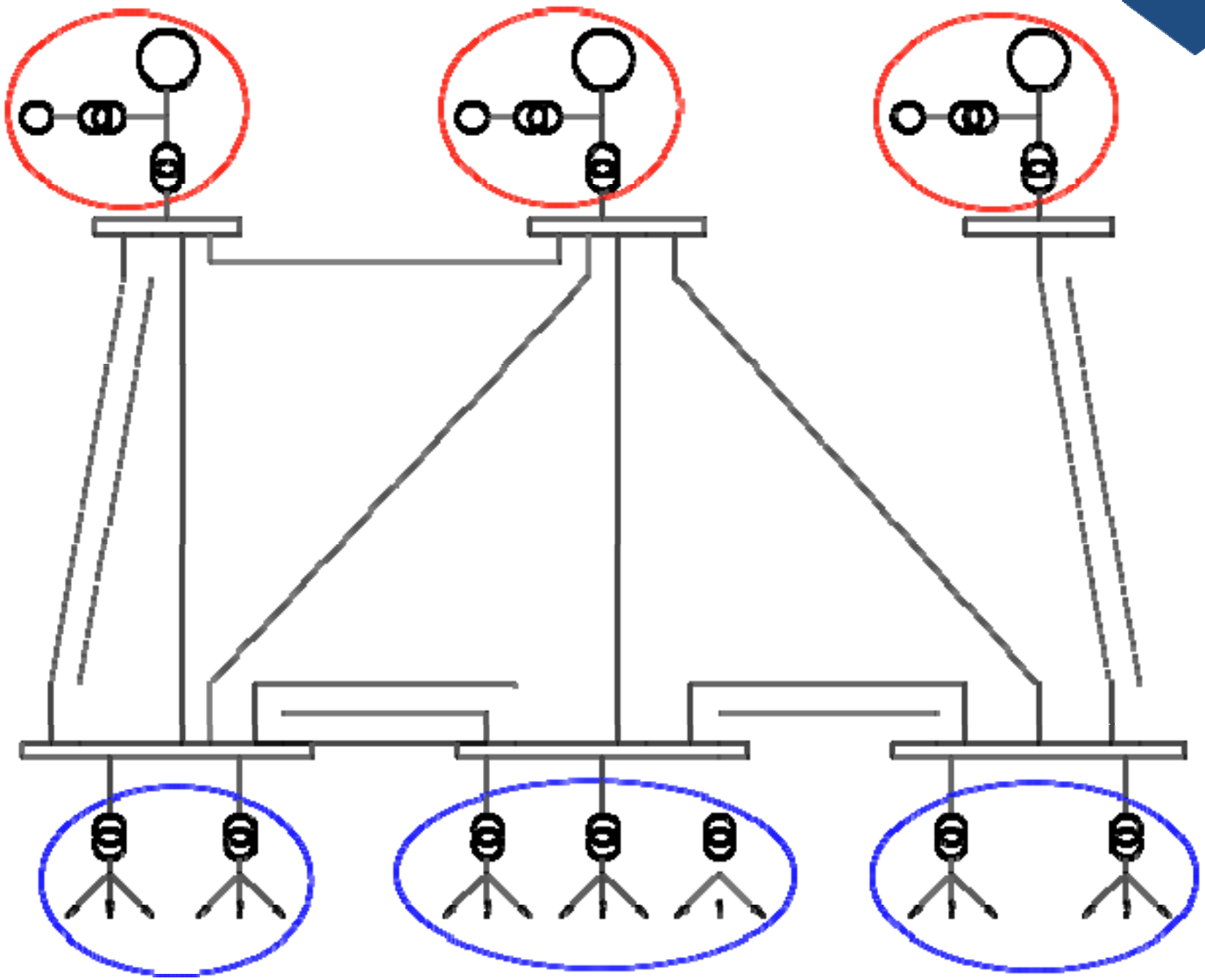
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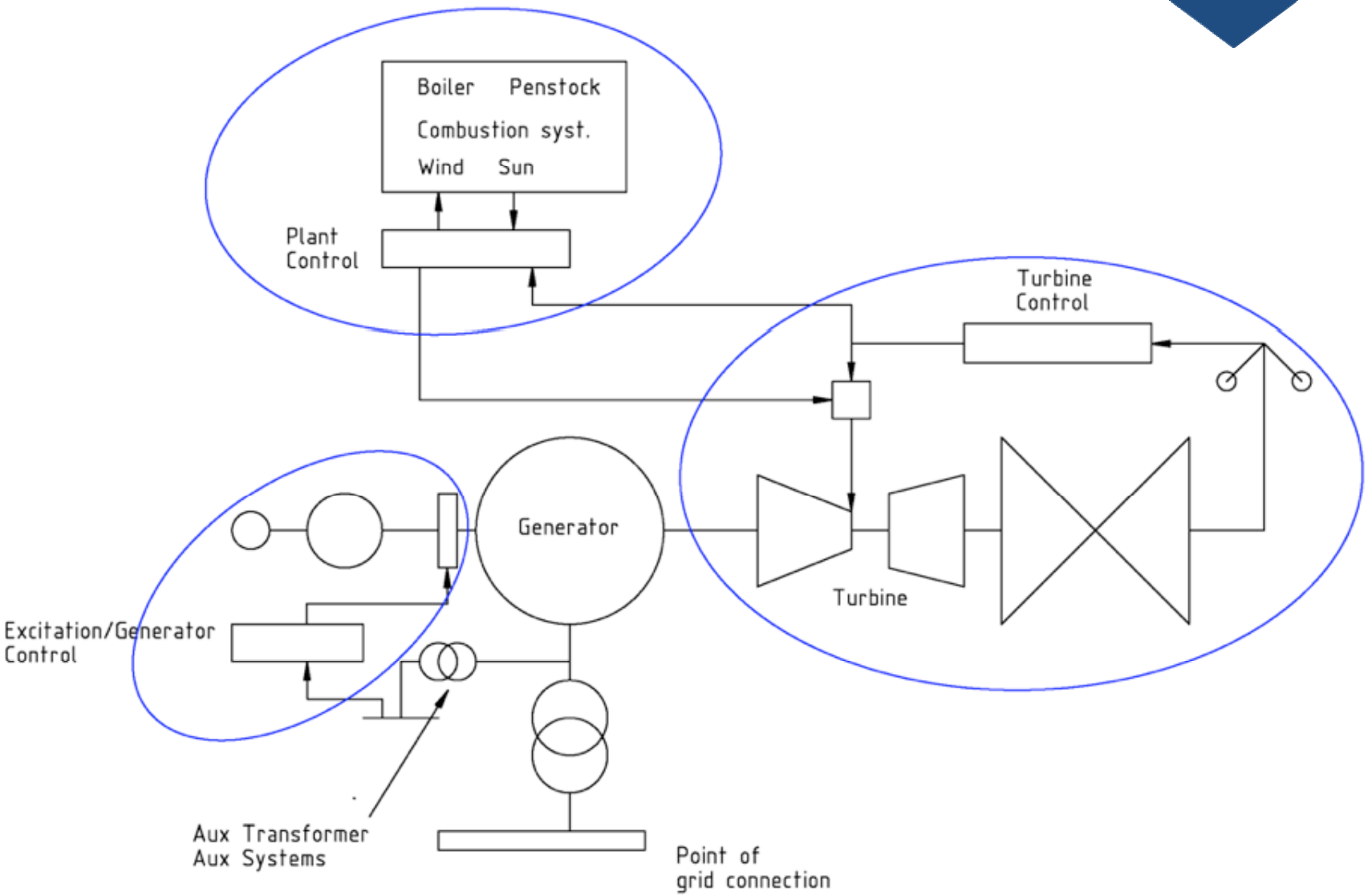


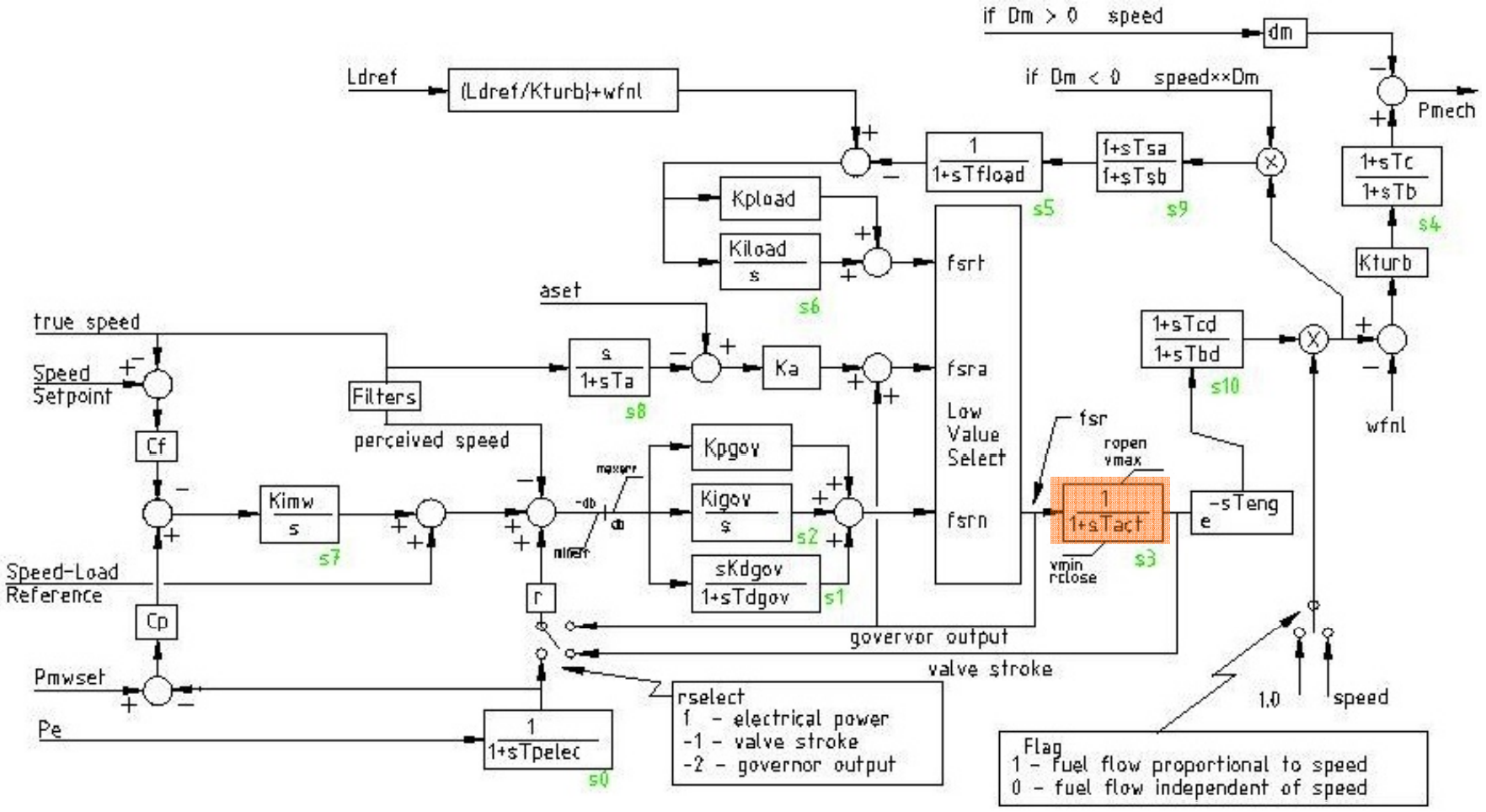




It's a Fan!
It's a Spear!
It's a Wall!
It's a Rope!
It's a Snake!
It's a Tree!

- We are concerned with interactions between power plants, the transmission grid, and loads
- We must consider :
  - steady and slowly varying conditions (load flow)
  - response to sudden events (transient stability)
  - dynamic characteristics in normal operation (damping)
  - interaction of subsystems within a plant
  - interactions between plants located far apart
- We are talking about modeling power plants in the context of the transmission grid.
- We are talking about interconnected models of thousands of generating units




Boiler
Penstock
Combustion syst.
Wind
Sun
Plant Control
Turbine Control
Generator
Turbine
Excitation/Generator Control
Aux Transformer
Aux Systems
Point of grid connection


if Dm > 0 speed
dm
if Dm < 0 speed××Dm
Ldref
(Ldref/Kturb)+wfnl
Pmech
1+sTc / 1+sTb
s4
Kturb
wfnl
1 / 1+sTfload
s5
1+sTsa / 1+sTsb
s9
Kpload
Kiload / s
s6
aset
fsrt
fsra
Low Value Select
fsrn
fsr
1+sTcd / 1+sTbd
s10
true speed
Speed Setpoint
Filters
perceived speed
s / 1+sTa
s8
Ka
Cf
Kimw / s
s7
Kpgov
Kigov / s
s2
sKdgov / 1+sTdgov
s1
maxerr
-db
db
minerr
r
ropen
vmax
1 / 1+sTact
s3
vmin
rclose
-sTeng
e
Speed-Load Reference
Cp
governor output
valve stroke
Pmwset
Pe
1 / 1+sTpelec
s0
rselect
1 - electrical power
-1 - valve stroke
-2 - governor output
1.0
speed
Flag
1 - fuel flow proportional to speed
0 - fuel flow independent of speed

Will this generating unit remain in synchronism after this transmission event starting in that grid flow condition

- This is the 'traditional' power system modeling/simulation problem
- Traditional modeling covers generators and transmission
  - Generator and generator control modeling is adequate
  - Improvement is needed in modeling of generator protection, remedial action schemes, transmission protection
- Improved protection speed alleviates the problem – increased transmission loadings aggravate it
- There is increasing reliance on 'remedial action schemes'
- These protections straddle the plant/transmission boundary
- Role of power plant controls is minimal

Will the power system develop unstable oscillations if the loading on this path rises to that level

- Known side effect of primary controls
  - Limiting factor on several key area-to-area transmission paths
  - Evolving load characteristics are unfriendly to this aspect of system behavior
- Proper modeling of primary controls is essential
- Improved load modeling is emerging as a critical requirement
- Internal protections at primary control level are not adequately modeled at present

Will the generation in this area increase its output as required if the transmission system operator requests it (via AGC) to compensate for loss of import capacity

- Plant secondary control capability is critical
- Requires modeling of turbine controls, boiler controls, tunnel/penstock characteristics
- Requires understanding of plant operating modes and practices

If grid frequency drops suddenly will there be sufficient primary control response in this area to arrest the drop and meet transmission security requirements

- Plant primary control response is critical
- Response must be prompt AND sustainable
- Modeling requires proper representation of
  - Primary AND secondary controls
  - Plant control modes and operating practices

Will this area be able to manage frequency / voltage / transmission flows if the wind dies quickly

- Plant secondary control response is critical
- Response must be prompt AND sustainable
- Modeling requires proper representation of
  - Primary AND secondary controls of the (conventional) plants that must replace the lost production
  - Plant control modes and operating practices

We can model specific machines very accurately

if/when we know that they need to be modeled

Modeling capability is far ahead of the ability of young engineers, who have never spent a week in a plant, to understand the physical, human, environmental, and risk assessment aspects of power plant operation

THE BIG QUESTION
(BOB CUMMINGS - NERC)

Will the plant trip 5 minutes after a grid event has run its course?

Modeling/simulation can't help with that

Why did that event knock the plant off?

Modeling might, or might not, help with this

How should equipment or operating practice be adjusted to ensure that it does not happen again?

Modeling is the essential ingredient here

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IS MODELING (as discussed here) A RISK ANALYSIS TOOL ?

- Risk analysis must identify the conditions and events whose consequences must be understood.
- Good modeling can show the consequences of a proposed event:
  - once the occurrence of the event has been conceived
  - and the relevant plant elements have been placed in the power system model

It is an important link in the chain

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Transmission Modeling Tools and Accuracy

Robert J. O'Keefe, American Electric Power

November 28, 2012

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Three Issues…

- Load Modeling
- Eastern Interconnection Model Data Management and Coordination
- Correlation Between Unidirectional Flow Patterns and Widespread Cascading Risk

Load Modeling – The Problem

- A long standing modeling problem: very difficult to accurately characterize / represent aggregate load behavior
  - Constantly moving target with wide variability – daily load curve, seasonal, geographical, substation-to-substation, and load class variability
  - Huge variety of load devices
- Recent discovery that modeling of single-phase A/C load is deficient; associated with fault induced delayed voltage recovery (FIDVR)
- Most planning studies do not depend on or require high accuracy, but some (particularly voltage instability/collapse analysis) have high sensitivity

Load Modeling – The Solution

- Sets of off-the-shelf composite dynamic load models representing various geographical, seasonal, time-of-day, and class variations
- Principal applications: uncovering possible voltage problem areas, and once uncovered, for sensitivity analysis
- WECC Region has led this development, and has produced such a set of off-the-shelf load models specific to western climate zones
- Need for ERCOT, Eastern Interconnection to follow

  (EPRI, ERAG?)

Model Data Management / Coordination Problems*

- Planning base case models often outdated even before they are finalized due to long development cycles
- Lack of efficient means to coordinate / translate between operations and planning models – leads to inconsistencies
- Difficulties in managing volume of data updates and assuring accuracy of in-service facilities for both planning and operations time-frames

Result is perhaps less than reasonable confidence in interconnection modeling and studies

*The Eastern Interconnection in particular

Model Data Management / Coordination – Ongoing Debate

- Entrenched base case development process (It works; don't fix it!) and diverse interests / perspectives make resolutions on future directions difficult
- Two key decision points:
  - Centralized interconnection database versus data owners maintaining their own databases
  - Impose operations detail (node-breaker) on planning models (presently bus-branch) versus devise translation mechanisms between operations and planning models

<u>Need to arrive at agreement on future directions among all parties</u>

Unidirectional Flow and Widespread Cascading - The Correlation

- Transmission outages not ordinarily expected to cause effects beyond an immediate locality lead / contribute to cascading well beyond it
  - Outages of facilities participating in a unidirectional flow pattern act to compound the load on remaining participating facilities
  - Increasing unidirectional flow thus sets up conditions that increase risk of cascading should system suddenly be hit with more than the “planned for” number of contingencies

Unidirectional Flow and Widespread Cascading - The Correlation

- Once uncontrolled cascading begins, ALL generation-load mismatched areas involved in a unidirectional flow pattern are affected

  Cascading proceeds along boundaries of generation-load mismatched areas until entire region participating in unidirectional flow resolves itself somehow – typically by separating into islands that may or may not survive

- Have viewed the allowed recovery time to return to N-1 secure state as a window of vulnerability

Unidirectional Flow and Widespread Cascading - What Should be Done?

- Supplement N-1 analysis with N-2+ when in a unidirectional flow environment (will require some strategic and heavy duty processing)…

  How quickly can a given multiple outage scenario initiate dynamic cascading? How many stages? Severity of conditions at each stage?

- Monitored area must encompass area of unidirectional flow; RC level oversight may or may not be adequate
- Possible supplementary criterion based on number of cascading stages before dynamic stage reached / severity of overloading (indicative of approximate time to trip) at each stage



Discussion

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Panel 2

Recent Events, Lessons Learned, and Moving Forward

The Arizona/Southern California Outage Event - Melanie Frye, WECC

Events Analysis and Trends - James Merlo, NERC

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The Arizona/Southern California Outage Event

Melanie Frye, WECC

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September 8, 2011 Event

- 11 minute cascading outage in Pacific Southwest
- 2.7 million customers out in AZ, S.CA, MX
- Initiated when a single 500 kV line tripped; not sole cause
- Power redistributed, increasing flows, dropping voltages and overloading equipment in underlying systems
- Led to tripping lines, generators, automatic load shedding, and operation of RAS and intertie separation scheme
- Restoration process generally effective

WECC's Comprehensive Response

Four Focus Areas

- Organizational Activities
- Reliability Coordination
- Operations and Planning
- Compliance

WECC

Western Electricity Coordinating Council
October 31, 2012

September 8 Event Recommendations
Monthly Progress Dashboard

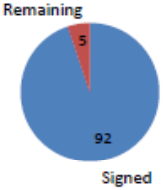
Key Accomplishments

- O&P20 - Activity is Complete. The default generator protection model has been added to the Master Dynamics File in monitor only mode and will be included in future base cases.
- ORG7 - A PCC Task Force of Subject Matter Experts has been formed to provide education on the Path Rating Process.
- RC10 - Activity is Complete. The WECC RC is sharing next-day studies in PTI format.
- O&P8 - A preliminary version of the Base Case Coordination System software tool was received at the end of September. Testing is underway.
- O&P5/6 - RAS Task Force is fully populated and a Scope of Work has been distributed.

Identified Risks

O&P7 - Approval Item for the Study Program Scope of Work was removed from the PCC agenda. A task force was formed to further review the Study Program process.
O&P10 - WECC is still in the process of executing an NDA with FERC to obtain the September 8 Dataset. Activity delayed.

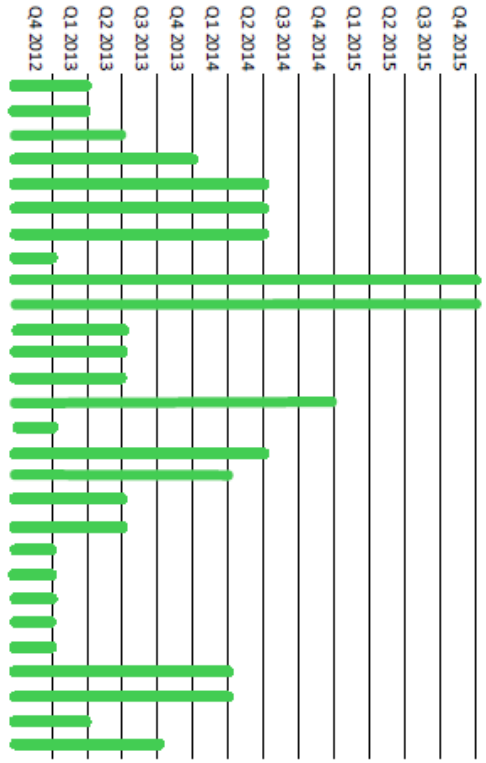
Universal NDA Signatories



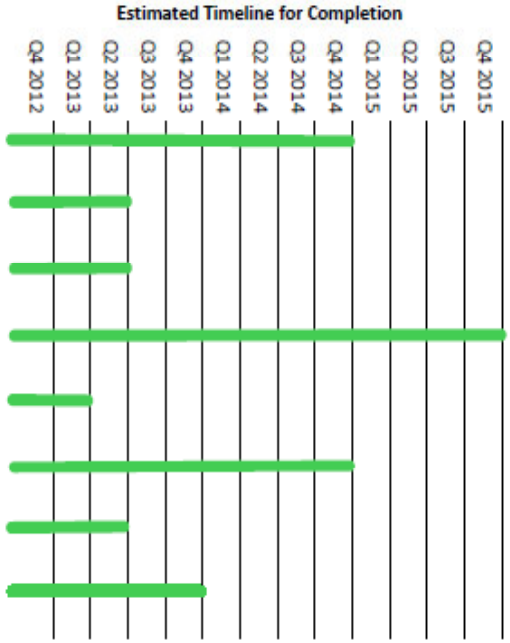
Completed Activity
In-Progress Activity is on schedule
Milestones have been missed, but Activity expected to be completed on time
Activity has not met Completion Deadline

Rec #	FERC/NERC Recommendations Short Description	Status of WECC Activities	% of Milestones Completed
1	Share next-day studies results	RC1, CPL2, RC10, O&P1, RC2, O&P2	76%
2	Next-day studies reflect next-day operating conditions	RC1, RC4, CPL2, RC10, O&P1, RC2, O&P2	79%
3	Next-day studies	RC15, RC3, O&P1, O&P2	44%
4	Predicting next-day interchange	RC10, RC9	20%
5	Integration & coordination of subregions' seasonal studies	O&P3, O&P4	30%
6	Include internal & external sub-100-kV facilities	O&P3, O&P4	30%
7	Include multiple base cases	O&P3, O&P4	30%
8	Share relay trip settings	O&P5	33%
9	Study cases cover critical system conditions across planning horizon	O&P4, O&P5, O&P6, O&P7, O&P8	38%
10	Benchmark models against actual data	O&P10, O&P5	31%
11	Real time data sharing	RC4, O&P12, RC5, RC18, O&P11, O&P22	31%
12	Real-time tools adequate	RC5, O&P13, O&P14, O&P22	27%
13	Post contingency plans	O&P1, O&P18, RC11	60%
14	RC Staffing Level	ORG4, ORG6, RC8, RC16	30%
15	Loss of real-time tools	RC13	0%
16	Consistency between planning and real-time models	O&P15	20%
17	Ensure all facilities impacting BPS in studies	RC3, O&P16, O&P21	7%
18.1	Study & monitor IROLs	RC6, CPL1, RC7, RC12	50%
18.2	SOLs constitute IROLs	RC6, CPL1, RC7, RC12	50%
19	Review of S-Line RAS	O&P17	57%
20	SONGS coordination w/protection schemes	O&P17	57%
21	Evaluation of turbine controls	O&P20, O&P19	50%
22	Periodic review of RAS	CPL1, O&P17	66%
23	Inadvertent Operations of SONGS	O&P17	57%
24	Ratings equal to most limiting equipment	RC12, O&P21	0%
25	Appropriate margins between settings & Emergency Ratings	O&P9, O&P21	13%
26	Increase relay settings to allow time for manual action	O&P9	33%
27	Tools to determine Standing Angle	O&P1, RC14	67%

Estimated Timeline for Completion



	NERC Systemic Issues	Status of WECC Activities	% of Milestones Completed
SI 1	WECC Reliability Coordinator Tools, Authorities, Capabilities, and Support	RC15 ORG4 RC3 RC8 RC9 RC11 RC12 RC13 RC14 RC17 ORG6 ORG7 O&P22	25%
SI 2	WECC Organization, Governance, and Conflict of Interest	ORG1	50%
SI 3	WECC Path Ratings and Interconnection Reliability Operating Limits	RC6 RC7 RC11 RC12	36%
SI 4	System Protection, Remedial Action Schemes, and Special Protection Systems	O&P5 O&P6 O&P9 O&P17 RC7	40%
SI 5	Data Sharing, Non-Disclosure, and Data Confidentiality Agreements	ORG3 RC1 RC4 RC10 RC2 RC5 ORG2 RC18	62%
SI 6	Roles and Responsibilities of Reliability Coordinator (RC), Balancing Authorities (BA), and Transmission Operators (TOPs)	RC1 RC4 RC6 ORG3 RC2 RC5 RC8 RC17 O&P13 O&P14 ORG7	61%
SI 7	Awareness and Recognition of Impacts of Sub-100-kV Systems on bulk power system reliability	RC3 O&P2 O&P9 O&P13 O&P16	30%
SI 8	ERO/Regional Entity Processes	CPL1 CPL2 ORG1 ORG5 CPL3 CPL4	55%



WECC Survey – June 2012

WECC conducted a detailed survey on:

- Next-Day Studies
- Seasonal Planning
- Near- and Long-Term Planning
- Situational Awareness
- Consideration of BPS Equipment
- Protection Systems
- Angular Separation

Survey results published on July 20 including identified gaps and best practices

Next-Day Planning

- A number of TOPs do not perform studies themselves
- External system conditions not included in all studies
- Not all TOPs study effects of sub-100 kV facilities

Seasonal Planning

- Inconsistent communication and modeling of planned outages
- No consistent criteria for including sub-100 kV facilities
- Some shoulder period studies do not consider planned outages
- Relay settings not always explicitly communicated
- Lack of universal participation in sub-regional seasonal studies

Near- and Long-Term Planning

- Inconsistent preparation of cases; lack of consideration of sub-100 kV facilities
- Limited communications regarding protection systems
- Examination of Remedial Action Schemes limited to internal studies

Considerations

- Planning Coordinator– identified some gaps in registration; working to determine reliability impact
- Coordination and data sharing along various planning horizons
- TOP visibility into neighboring systems

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Event Analysis and Trends

James Merlo, PhD
Associate Director, Human Performance - NERC
November 28, 2012

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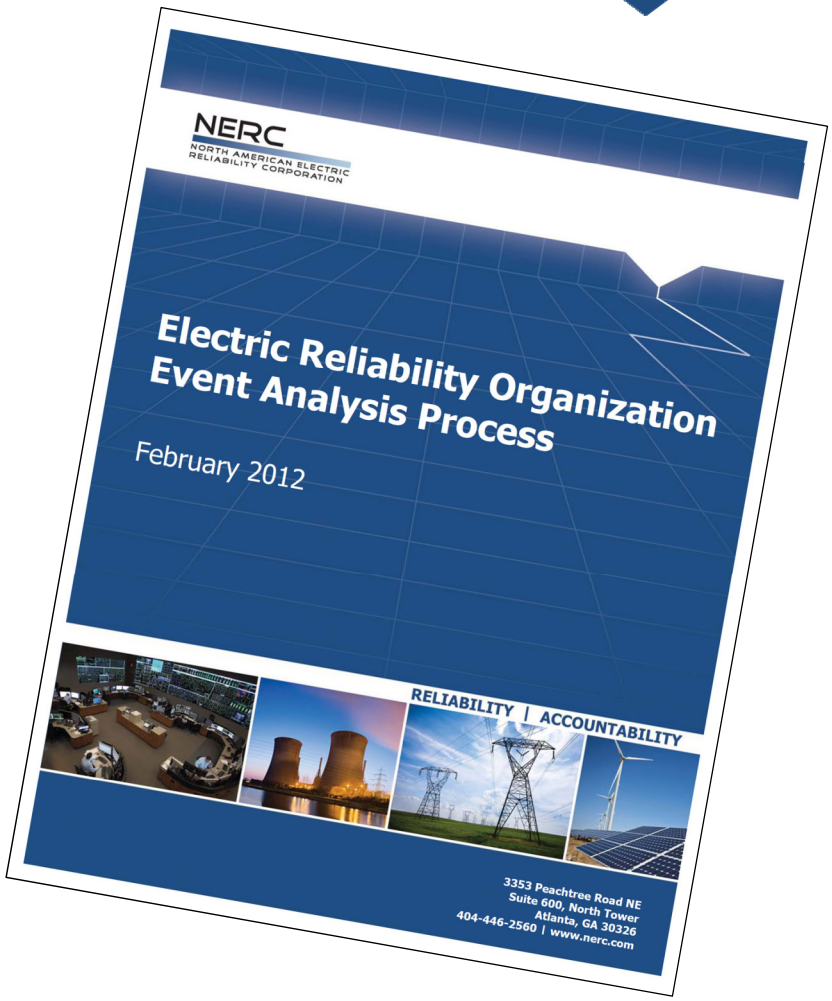

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Agenda

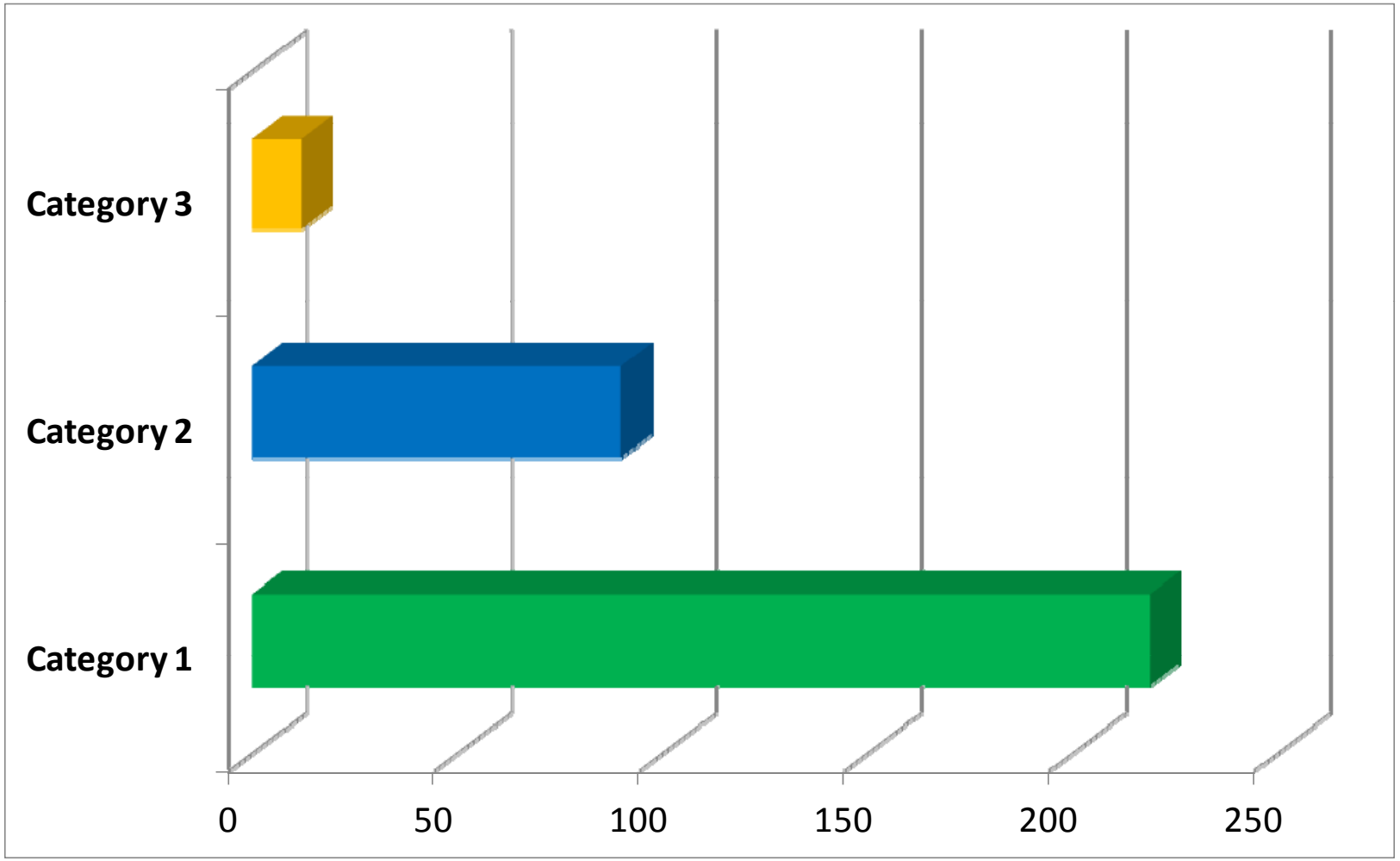
- History of Events Analysis (EA) Process
- Update on Reported Events to Date
- Cause Coding Process
- Initial Trends and Clusters
- Questions

History

- EA Field Test began in October 2010
- Phase II Field Test began May 2011
- Approved ERO Process in February 2012
- Over 300 qualified event reports received to date



Total Events (Cat 1 – Cat 3)



as of 5 Nov 2012

Cause Code Assignment Process

- North American Electric Reliability Corporation Cause Code Assignment Process (NERC CCAP)
- Cause coding program to guide, assist, and inform industry
- Opportunity to collect and disseminate reliability data and information across NERC and industry
- Fosters trust and collaboration

Cause Code Assignment Process (CCAP)

Main Cause Codes

- A1 - Design/Engineering Problem (23 sub codes)
- A2 - Equipment/Material Problem (27 sub codes)
- A3 - Individual Human Performance LTA (20 sub codes)
- A4 - Management Problem (46 sub codes)
- A5 - Communication LTA (25 sub codes)
- A6 - Training Deficiency (11 sub codes)
- A7 - Other Problem (8 sub codes)
- AZ - Information to determine cause LTA

LTA – Less than Adequate

A3 - Human Performance

Cause Code Assignment Process (CCAP)

- A1 Design/Engineering Problem
- A2 Equipment/Material Problem
- A3 Individual Human Performance
  - B1 SKILL BASED ERROR
  - B2 RULE BASED ERROR
  - B3 KNOWLEDGE BASED ERROR
  - B4 WORK PRACTICES
- A4 Management Problem
- A5 Communication LTA
- A6 Training Deficiency
- A7 Other Problem

A3 - Human Performance

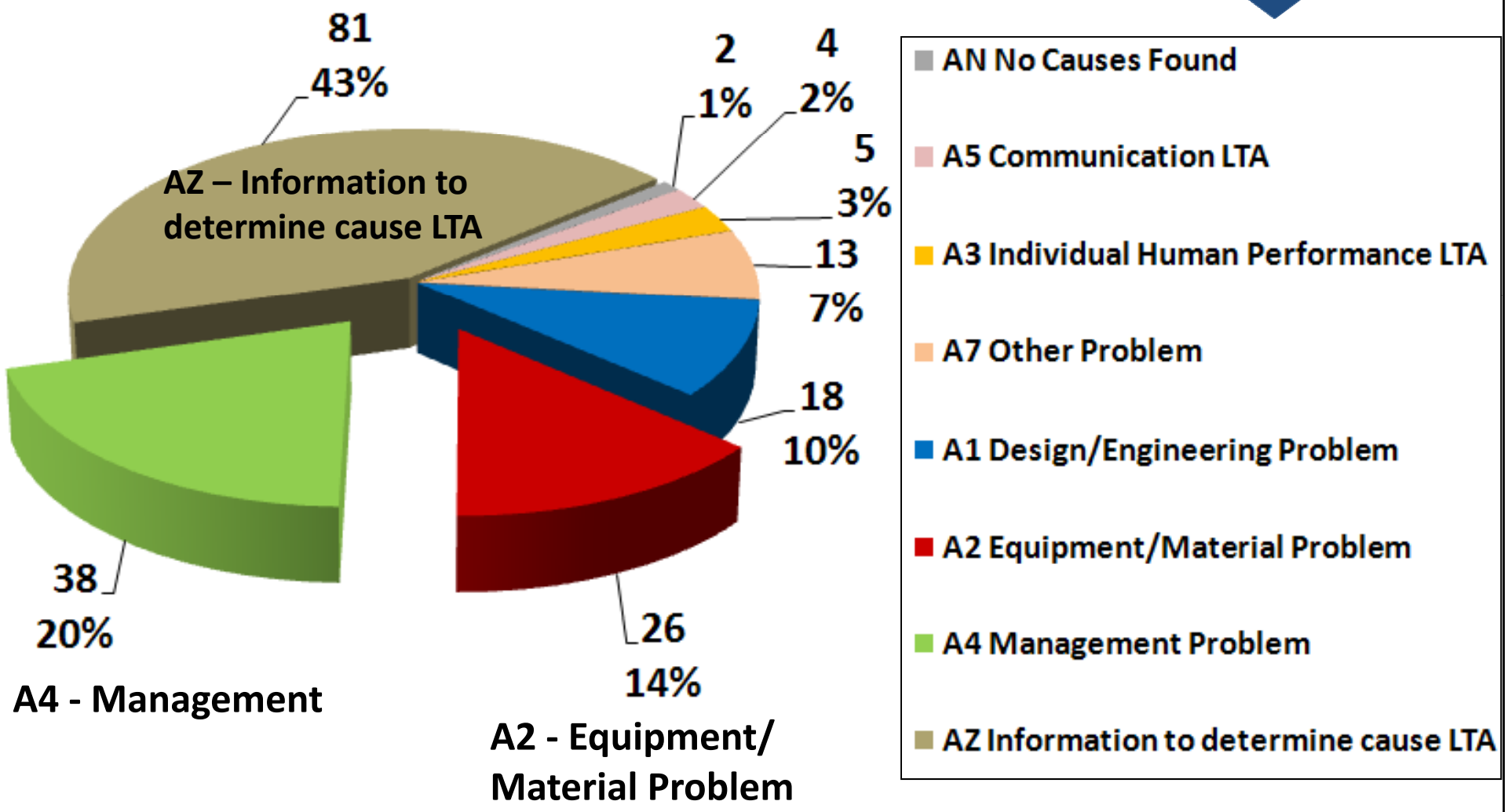
Cause Code Assignment Process (CCAP)

- A3 Individual Human Performance
  - B1 SKILL BASED ERROR
    - C01 Check of work LTA
    - C02 Step was omitted due to distraction
    - C03 Incorrect performance due to mental lapse
    - C04 Infrequently performed steps were performed incorrectly
    - C05 Delay in time caused LTA actions
    - C06 Wrong action selected based on similarity with other actions
    - C07 Omission / repeating of steps due to assumptions for completion
  - B2 RULE BASED ERROR
  - B3 KNOWLEDGE BASED ERROR
  - B4 WORK PRACTICES

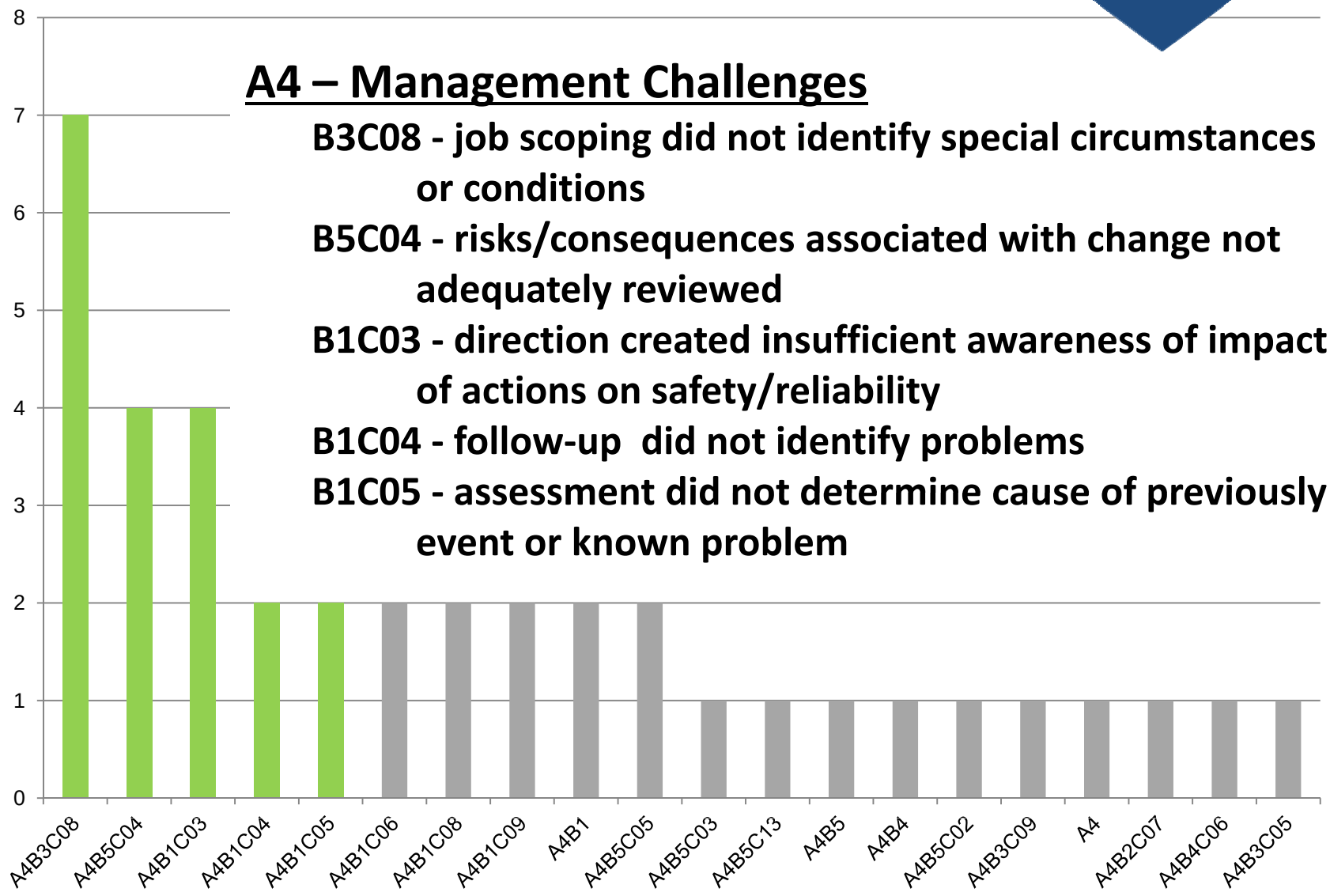
Cause Code Definitions

- **AZ - Information to determine cause LTA - Information provided to determine a cause is "Less Than Adequate (LTA)."**
- **A4 - Management Problem/Challenges - An event or condition that could be directly traced to managerial actions, or methodology (or lack thereof).**

Root Cause Determinations



Deeper Dive into Organizational Issues (based on Root Causes)



A4 – Management Challenges

B3C08 - job scoping did not identify special circumstances or conditions

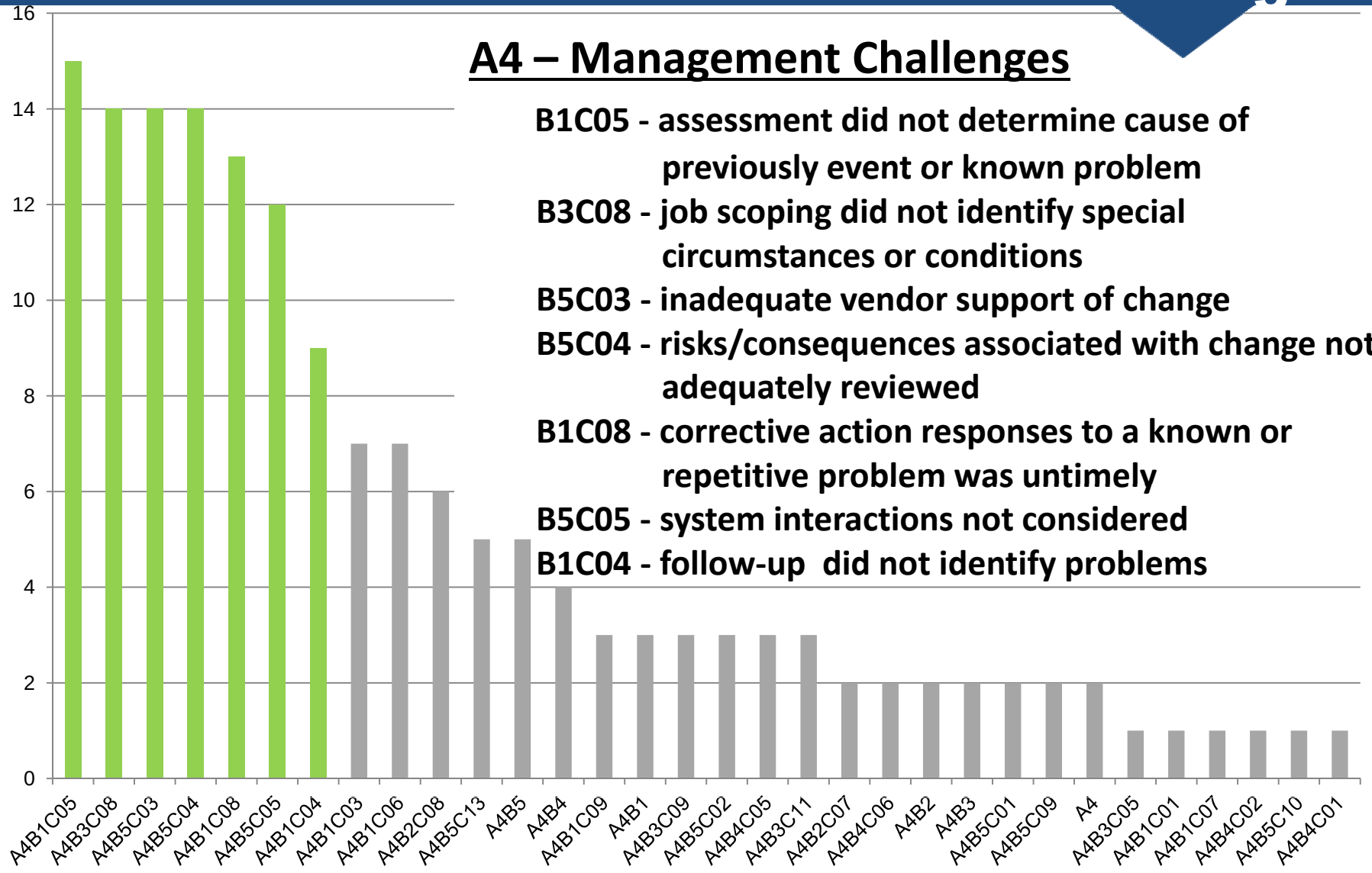
B5C04 - risks/consequences associated with change not adequately reviewed

B1C03 - direction created insufficient awareness of impact of actions on safety/reliability

B1C04 - follow-up did not identify problems

B1C05 - assessment did not determine cause of previously event or known problem

All Causes for Management Issues/Challenges



A4 – Management Challenges

B1C05 - assessment did not determine cause of previously event or known problem

B3C08 - job scoping did not identify special circumstances or conditions

B5C03 - inadequate vendor support of change

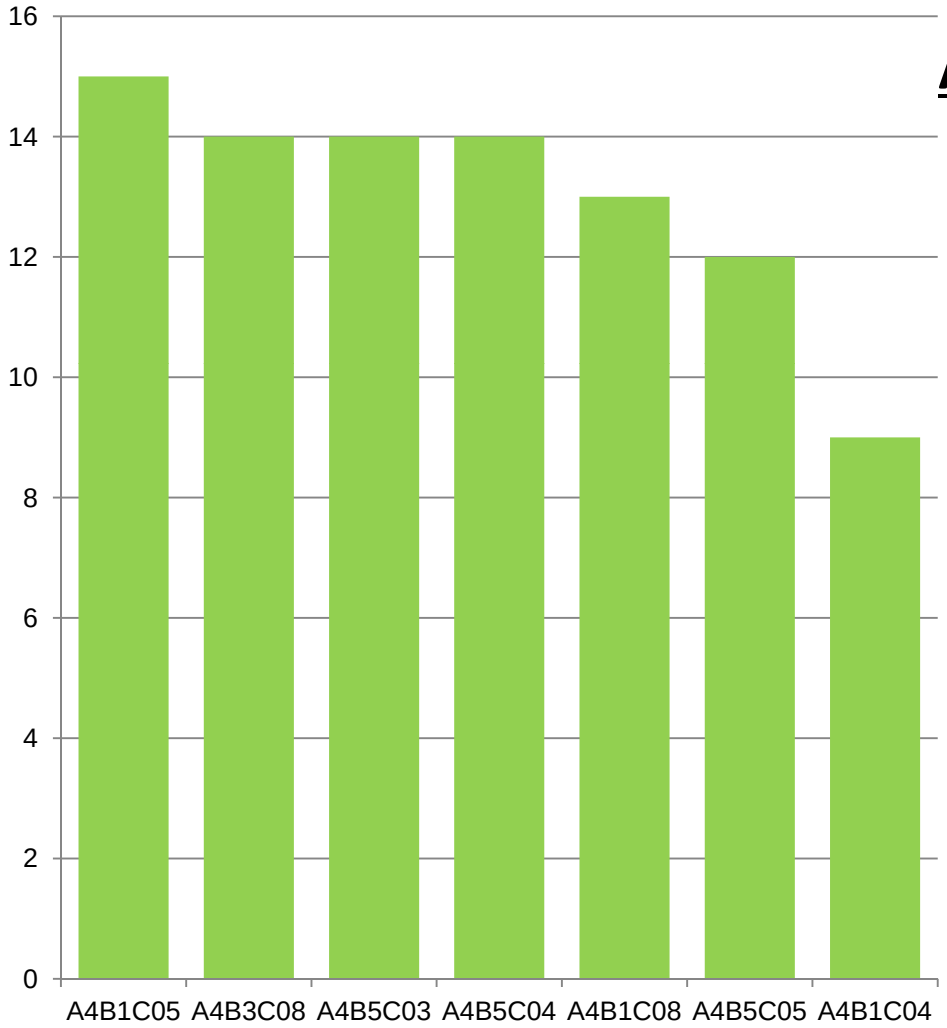
B5C04 - risks/consequences associated with change not adequately reviewed

B1C08 - corrective action responses to a known or repetitive problem was untimely

B5C05 - system interactions not considered

B1C04 - follow-up did not identify problems

All Causes for Management Issues/Challenges



A4 – Management Challenges

B1C05 - assessment did not determine cause of previous event or known problem

B3C08 - job scoping did not identify special circumstances or conditions

B5C03 - inadequate vendor support of change

B5C04 - risks/consequences associated with change not adequately reviewed

B1C08 - corrective action responses to a known or repetitive problem was untimely

B5C05 - system interactions not considered

B1C04 - follow-up did not identify problems

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Summary

- Less than adequate Job Scoping is a threat to reliability
- Less than adequate Event Analysis can result in real threats not being remediated
- Event Analysis process has potential to provide high quality reliability information
- Training for Event Analysis process
- QA/QC of submitted Event Analysis reports
- Expanded Lessons Learned program



Discussion

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Panel 3

Changing Landscape

Impact of Weather Trends and Drought on Supply –
Nick Abi-Samra, Quanta Technology
Increasing Dependency on Natural Gas - Frank Koza, PJM

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Impact of Weather Trends and Drought on Supply

Nick Abi-Samra, Quanta Technology

November 28, 2012

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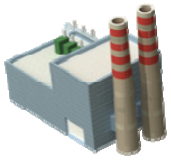
Contents

- Vulnerability of the power system to extreme weather effects
- NOAA's July 2012 Report
- Super storm Sandy
- Selected Extreme Weather Events
  - Droughts
  - Heat storms
  - Wind Storms
  - Floods

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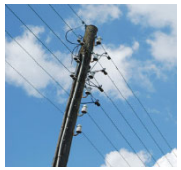
Selected Impacts of Extreme Weather















Floods

Floods

Floods

Wind Storms

Wind Storms

Cold Snaps

Droughts

Droughts

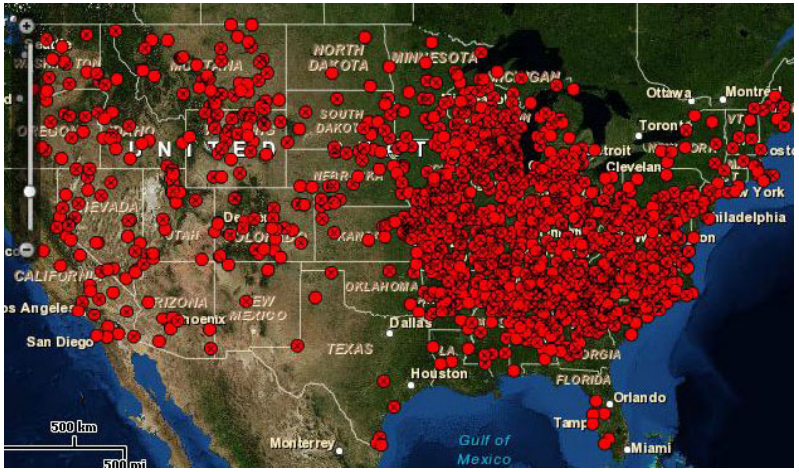
Heat Waves

Wildfires

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NOAA's July 2012 Report

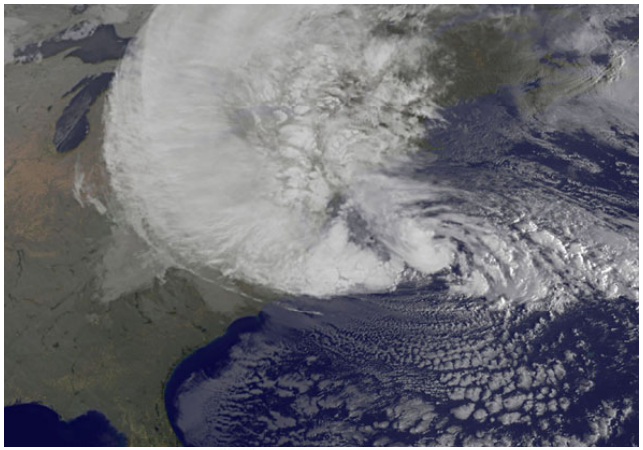
- National Oceanic and Atmospheric Administration (NOAA) Report:
  - July 2012 was the **hottest** month on record for the contiguous United States.
  - Over 63% of the **contiguous United States experienced "moderate to exceptional"** drought conditions.
  - Period between January and July was the **warmest first seven months of any year** on record for the contiguous United States





Then Came Sandy…

- Largest Atlantic hurricane on record (measured by diameter with winds spanning **1,100 miles** (1,800 km)).
- Affected 24 states: including the entire eastern seaboard with lesser impacts in the Southeastern and Midwestern states
  - Severe damage in New Jersey and New York
  - Storm surge in New York City - flooding streets, tunnels and subway lines and cutting power in and around the city
- Was only category **2** storm at its peak intensity!





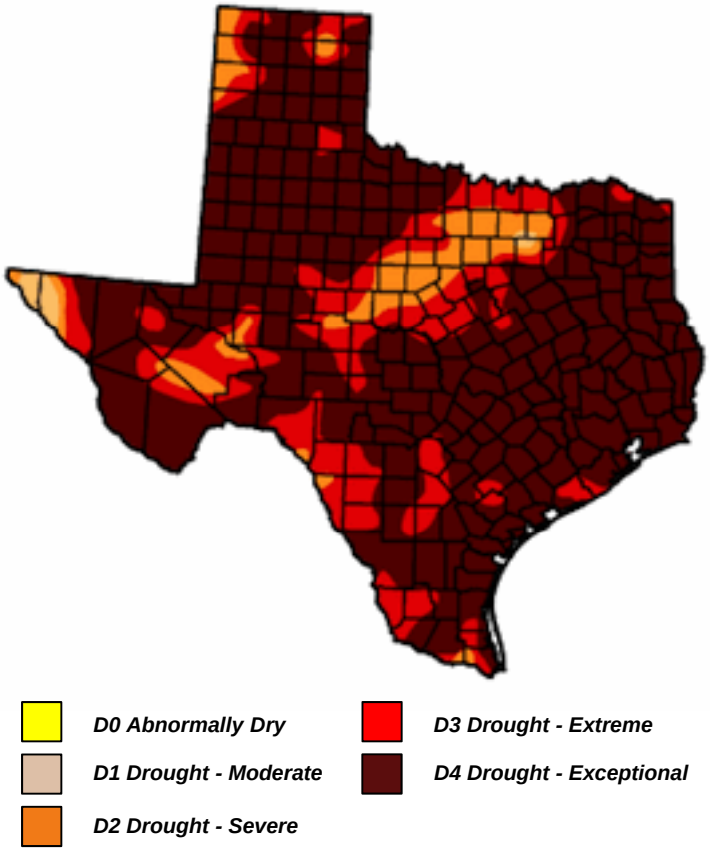
Impacts on Thermal Generation

- Increased generator forced outage
- Regulatory Issues
  - Water withdrawal lakes/reservoirs
  - Maximum discharge temperature limits
  - Priority for water rights during drought conditions
- Short Term Solutions
  - Conserve energy output
  - Energy conservation measures
  - Limited operations except during periods of critical demand
- Long Term Solutions
  - Dry Cooling towers
  - Good maintenance practices



Droughts

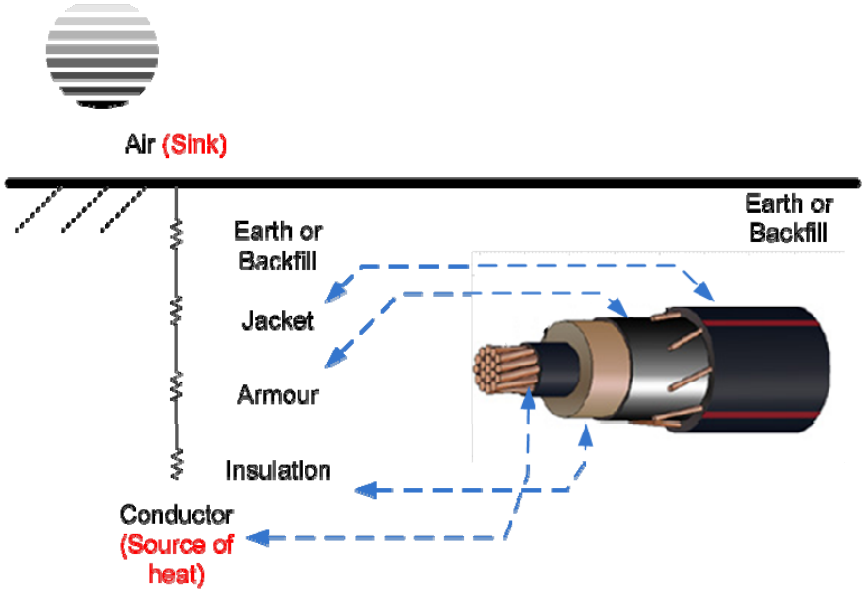
Drought Conditions in Texas

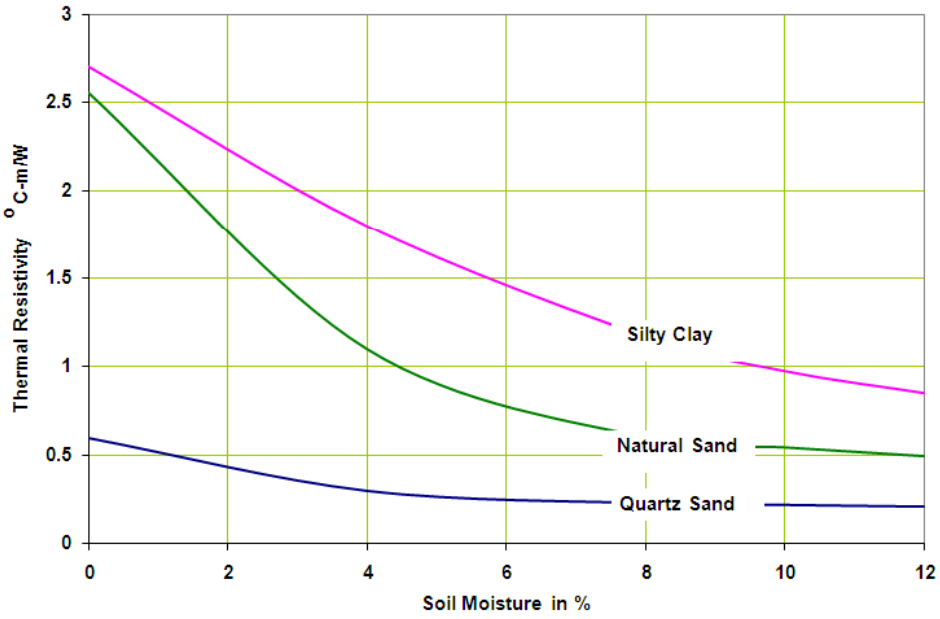


- DOE report: In 2011, at-risk thermoelectric generation from drought related outages in the Texas Gulf basin approached 70% total capacity.
- Dropped to 25% in 2012.

Droughts

Soil Moisture

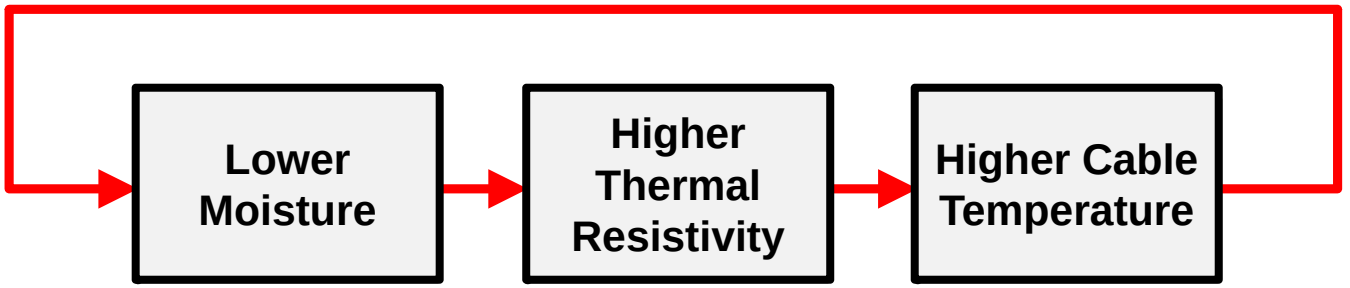




Droughts

Runaway Conditions in U/G Cables

- Droughts or prolonged high temperatures = drying of soil



Thermal Runaway Scenario

Droughts

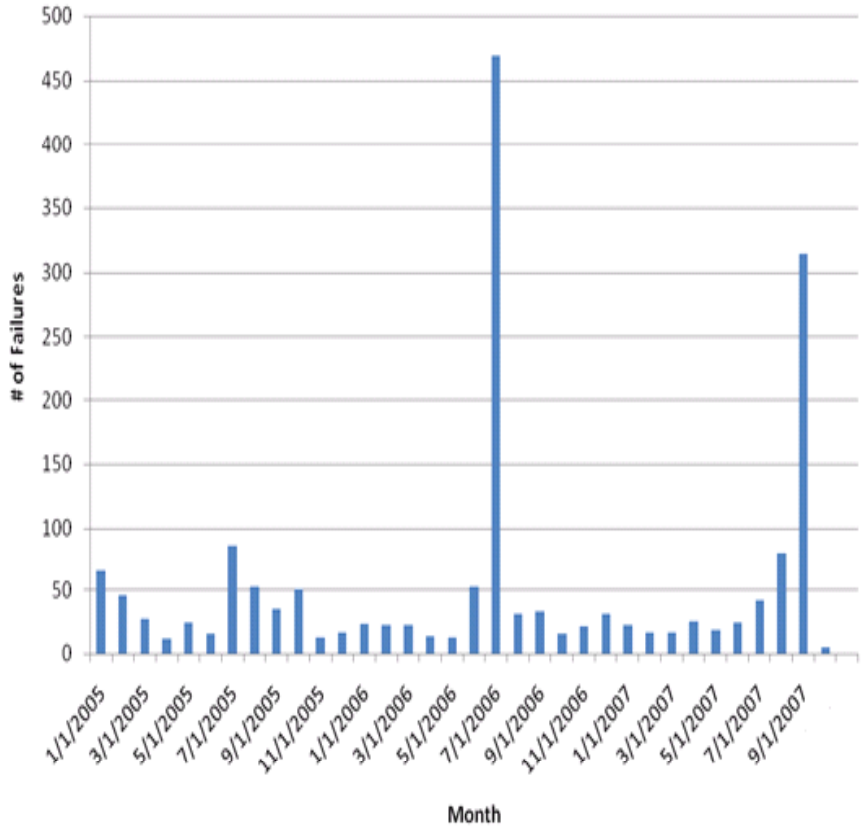
2006 and 2007 Heat Waves
Western US States

- Both events lasted roughly 4 to 5 days.
- The air temperature during each heat storm was in the upper 90's, peaking at 101°F (mid to upper 30's °C)
- Relative humidity values were in the range of 60 to 70%.
- Both events occurred over a weekend, beginning on a Friday and easing early the following week.
- The failures during the 2006 and 2007 heat waves averaged roughly 100 per day.

Heat Waves

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Distribution Transformer Failures in 2006 and 2007 Due to Heat Waves



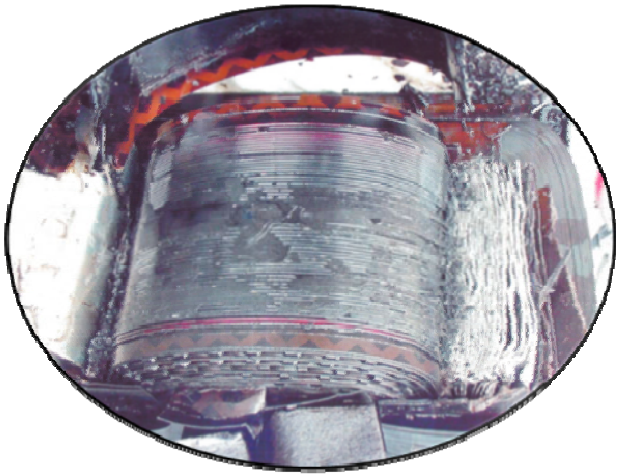


Heat Waves

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Selected Findings On Distribution Transformer Failure Rates

- For the analyzed data, the failure rates during heat storms showed a **dependence on age**, indicating that some mechanism related to aging is a contributing cause to the failures. Yet, there was no clear or consistent age threshold that results in a marked increase in failure rate.
- The rate at which a transformer ages increases exponentially if the **load exceeds nameplate** capacity at ambient conditions that are equal to or greater than rated values. Based on loading, few days of heat storm can lead to failure.
- Failure rates for young transformers, however, were still as much as 25 times their average annual failure rate.

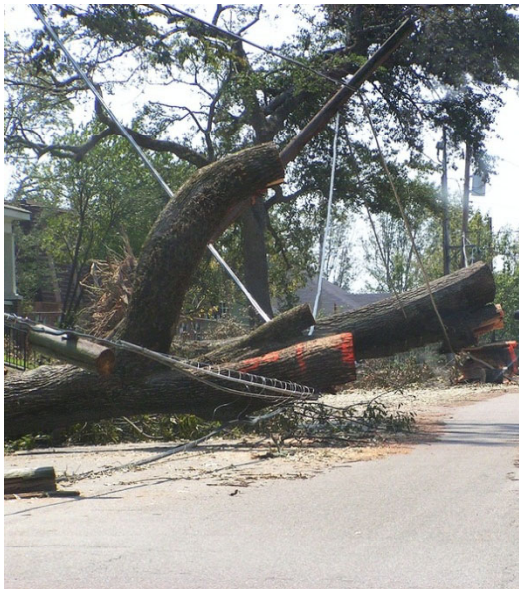


Heat Waves

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Wind Storms







The single largest risk factor for distribution infrastructure for wind storms is vegetation-caused outages.

Wind Storms

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Floods

- Affect many aspects of the power system, but is a major concern to **substations**
  - Severe damage to substation equipment
  - Interruptions in service continuity and widespread outages
- Could be the **most significant extreme** weather event because of the **long-term effects** of flood water damage in substations



Floods

Flooding - *Countermeasures*

- Cleaning the grounds in and around the substation from debris and materials so that water runs off freely
- Consolidating load on the minimum number of energized transformers
- Removing relays which are not in use
- Sealing and waterproofing equipment as much as possible when practical.



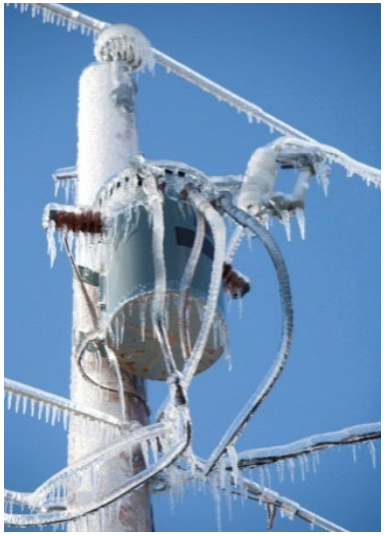
Floods

Concluding Remarks

Extreme weather will impact all aspects of the power system: generation, transmission and distribution

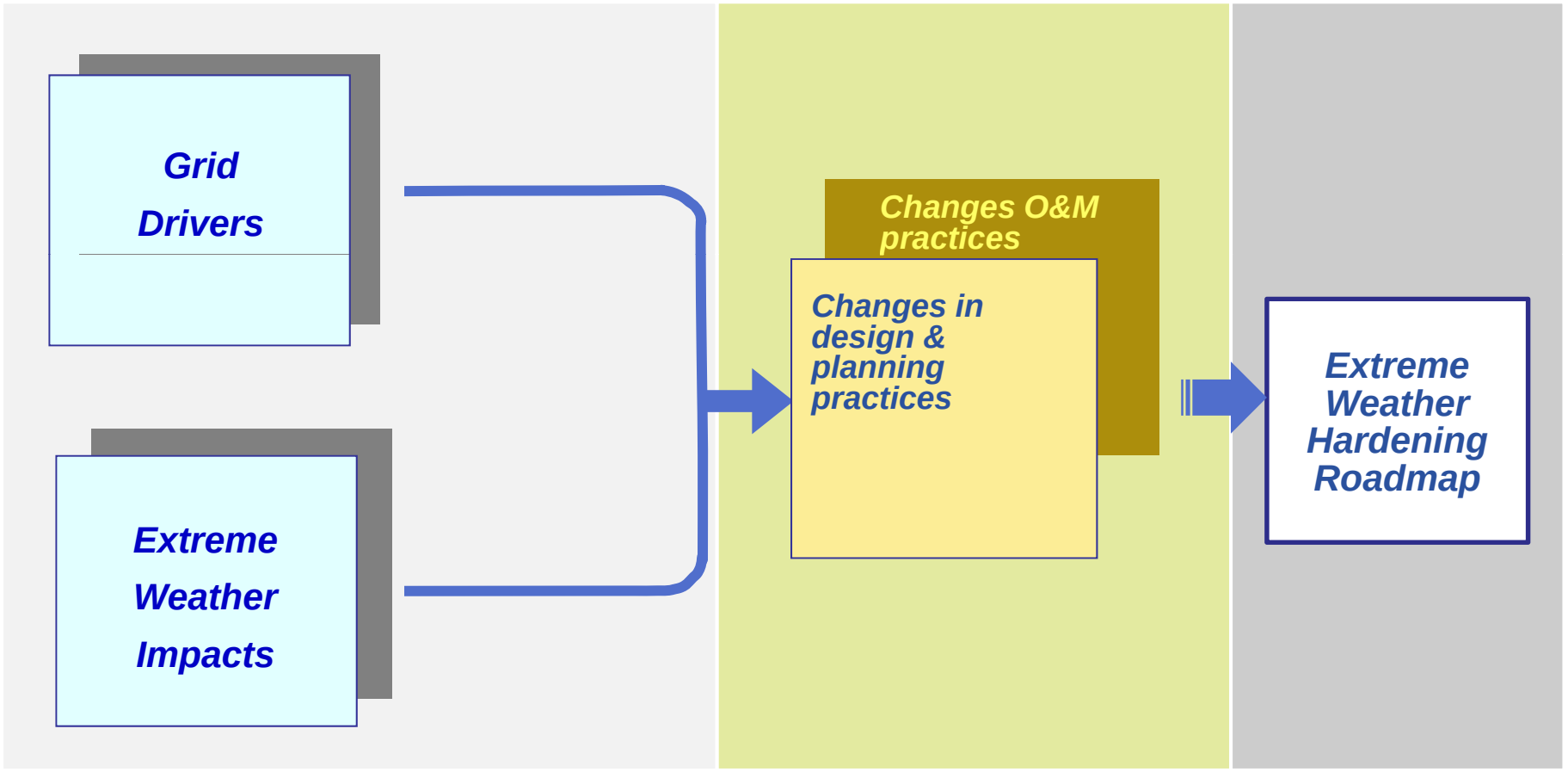
Other concurrent drivers on the grid:

- Aging infrastructure
- Increased electric energy usage
- Constrained transmission and distribution systems
- Increased usage of renewables
- Demands for higher security of supply and reliability of the network
- Requirements for faster restoration
- Smart grid



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Extreme Weather Hardening



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Increasing Dependency on Natural Gas

Frank Koza, PJM

November 28, 2012

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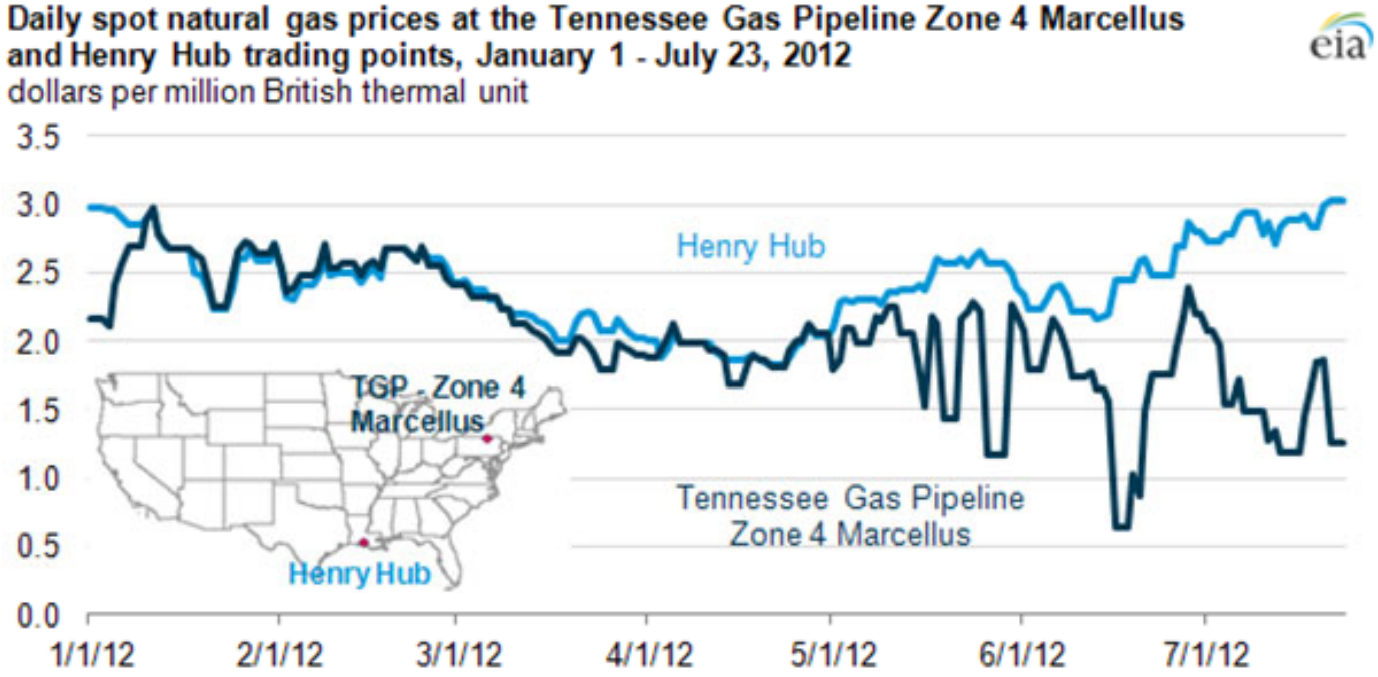




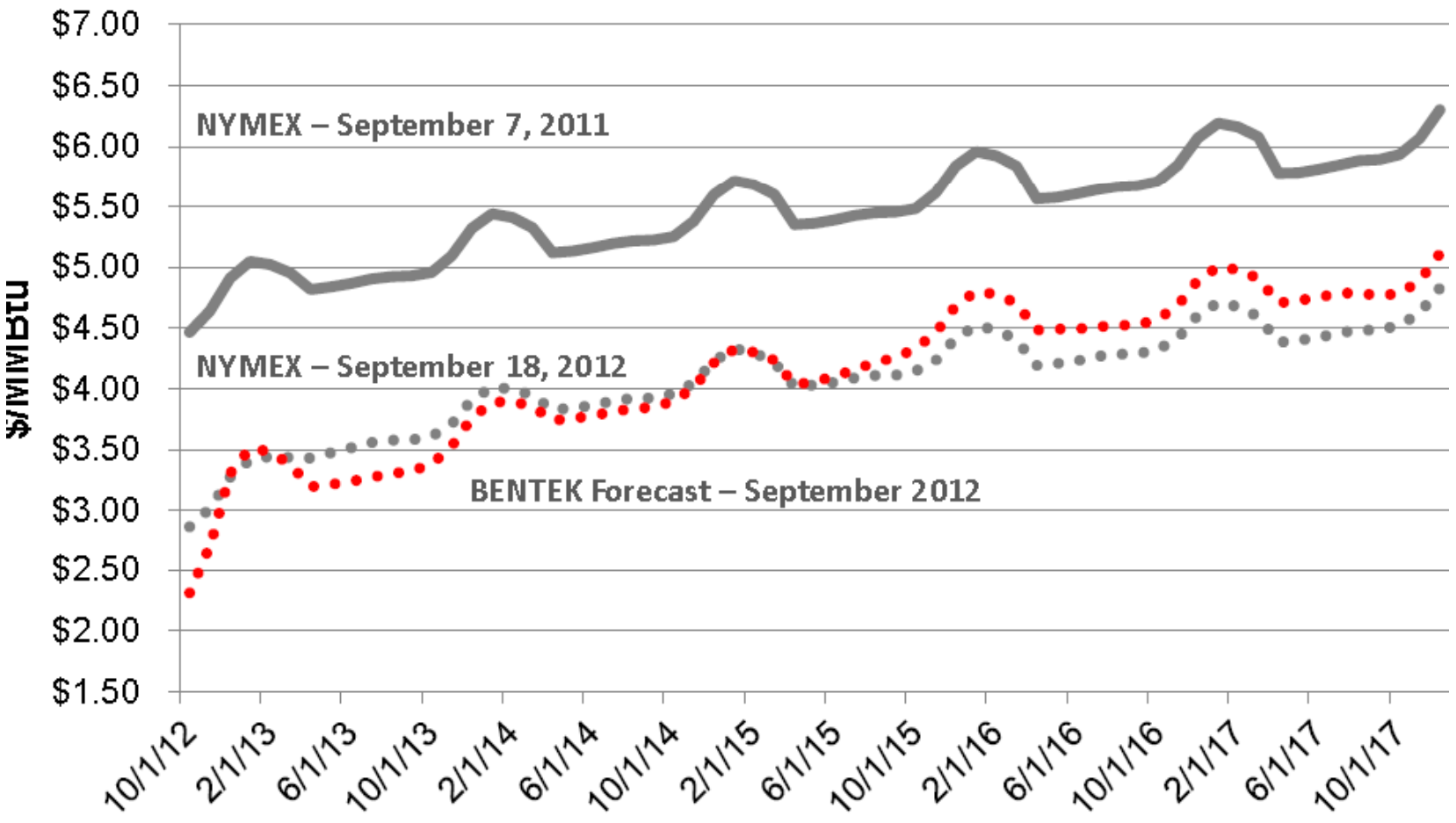

Game Changer #1

SHALE GAS at low prices!

- Low commodity prices, translating to dramatically increased gas consumption for power generation—Marcellus is the cheapest gas in North America!



NYMEX Forward Price Curve

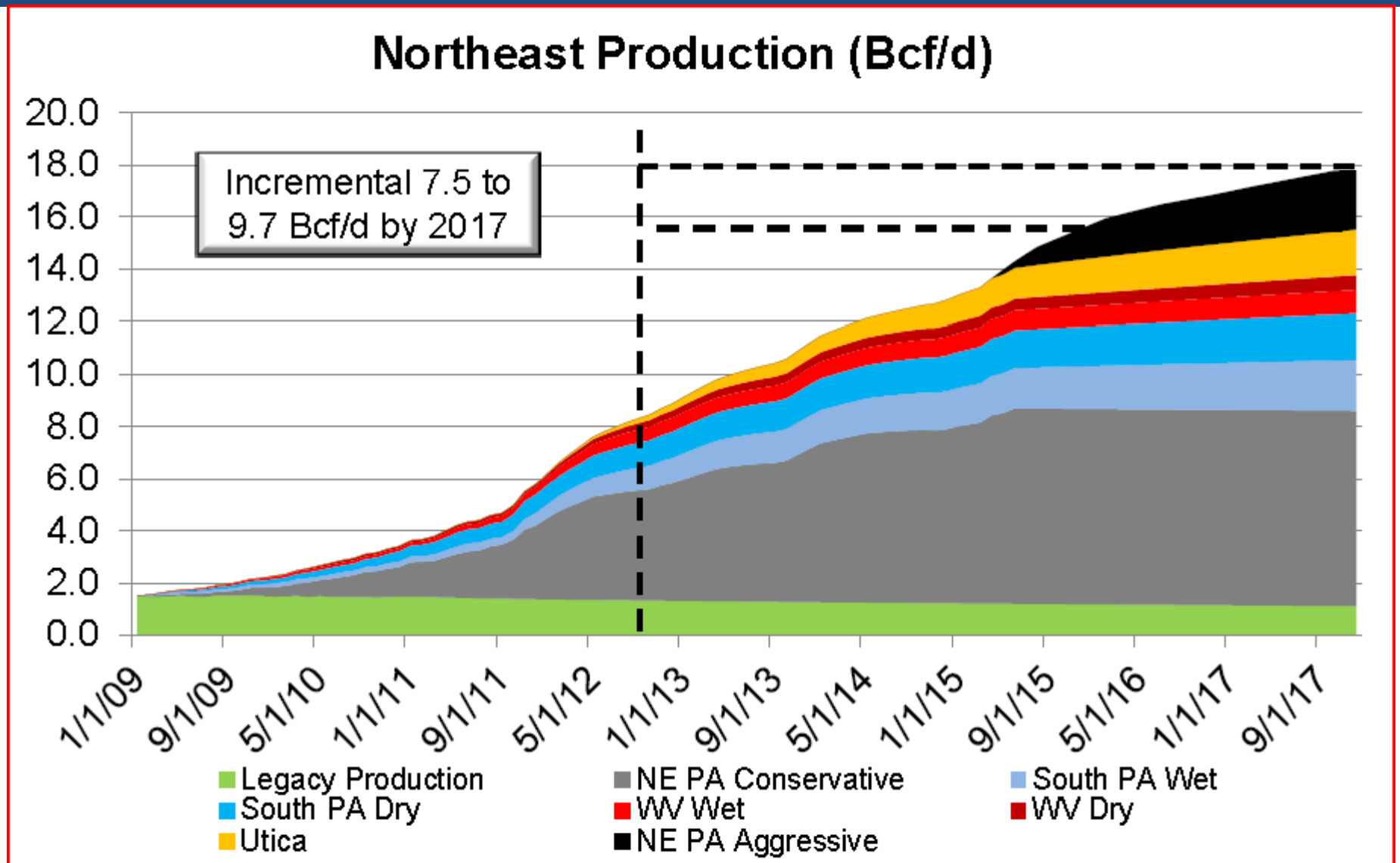


- Low prices for the foreseeable future!

Source: BENTEK Energy

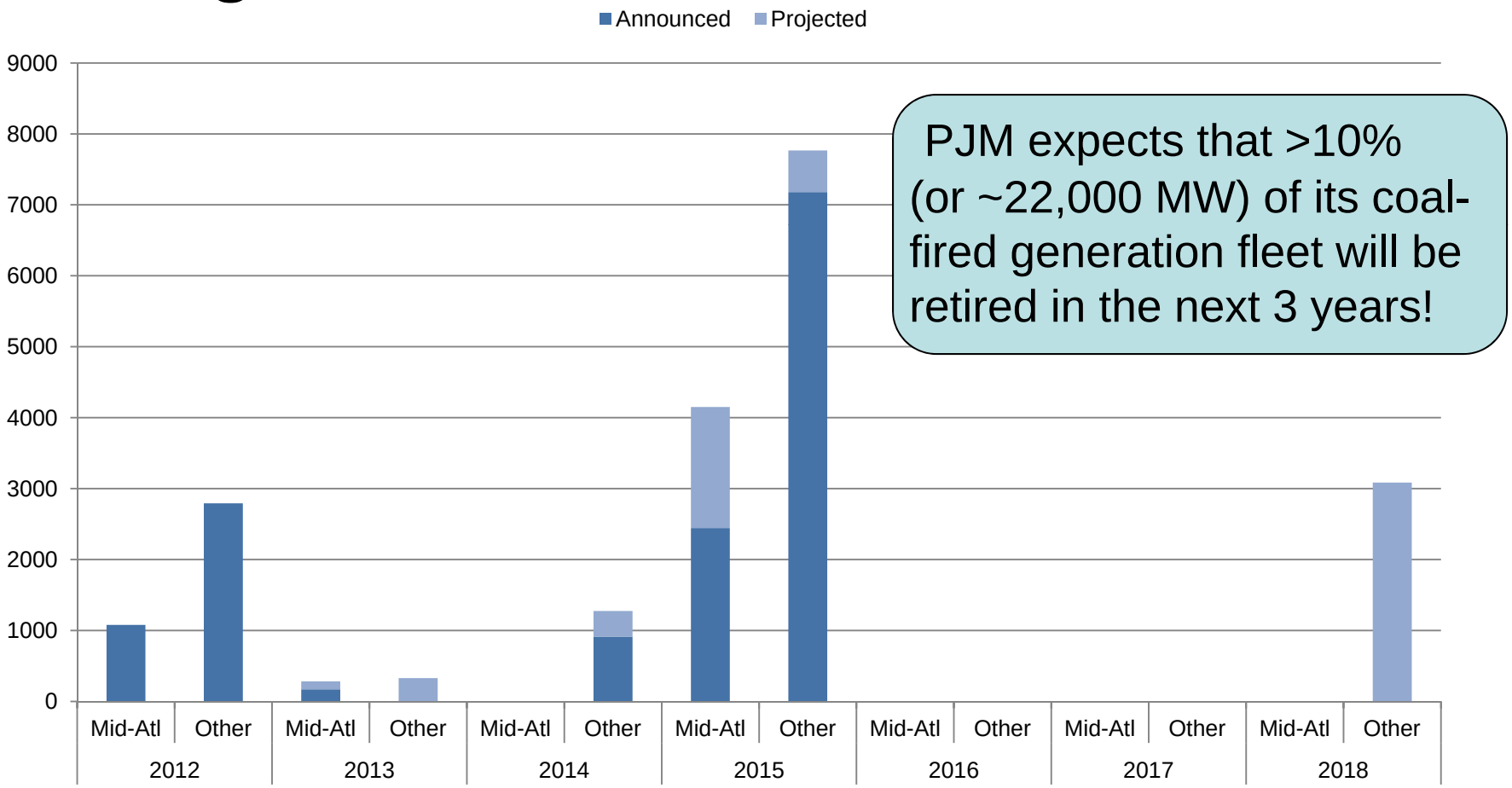
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Marcellus/Utica Output



Game Changer #2

EPA Regulations



PJM expects that >10% (or ~22,000 MW) of its coal-fired generation fleet will be retired in the next 3 years!

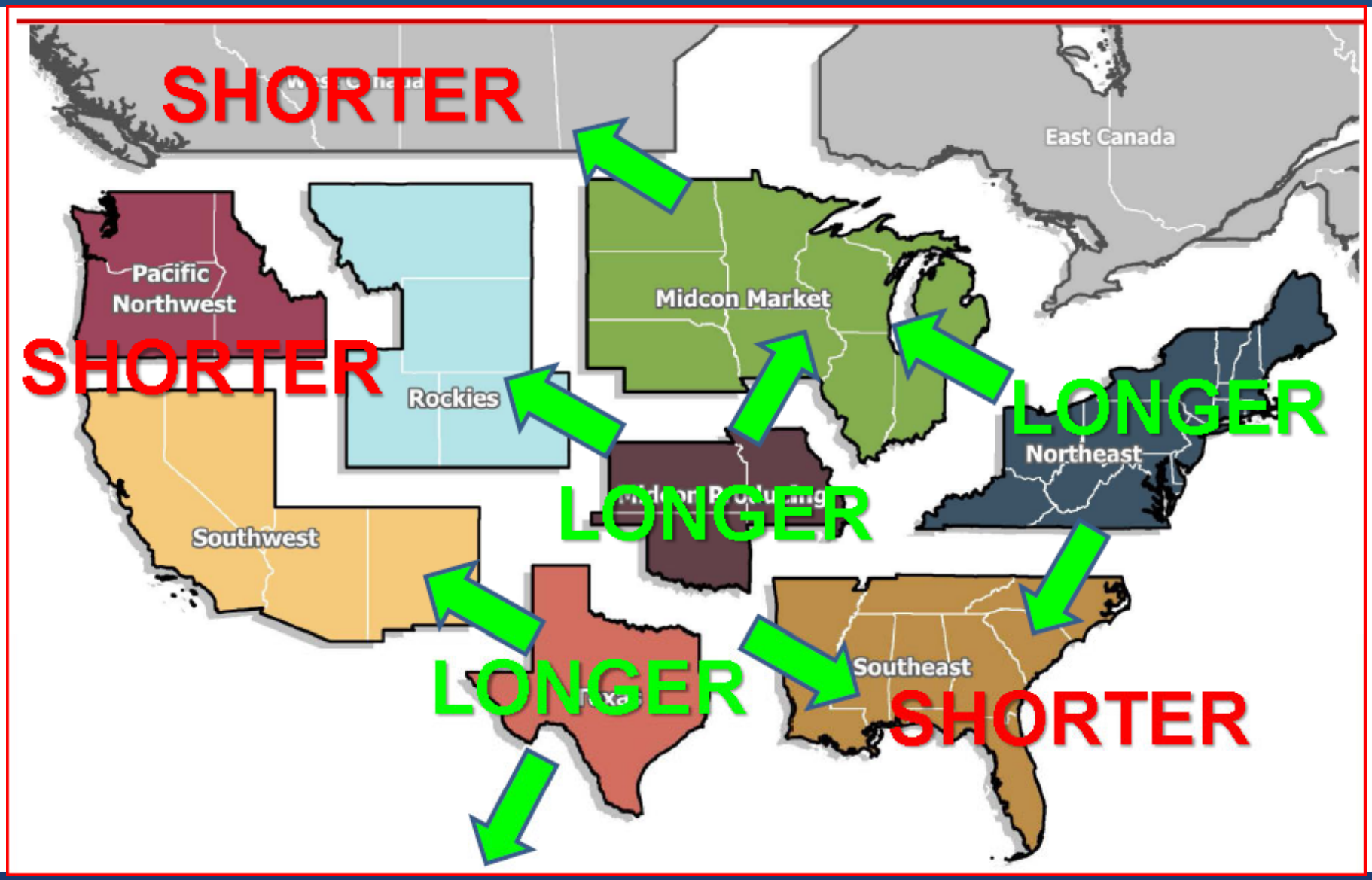
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What's Needed

- Pipeline Expansion to Serve New Generation Demand
  - Existing gas infrastructure experiences congestion, especially in New York and New England
  - Southeast US and Ontario require additional pipeline capacity to serve new generation and conversions
- More coordination in operations between Gas Control and electric system operations
  - Electricity brings more intermittency and fluctuation in demand to the gas system, much like wind and solar bring to electricity
  - Low gas prices are changing the basic dispatch of the power system

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Changing the Flow Dynamics



Spectra Energy Expansion Map

Connecting Marcellus & Utica Supplies to Our Diverse Markets



Texas Eastern Appalachia to Market
TEAM 2014
Providing producers access to diverse Texas Eastern markets

Ohio Pipeline Energy Network
OPEN (2015)
Connecting Utica production to diverse Texas Eastern markets

Algonquin Incremental Market
AIM (2016)
New England market pull combined with Northeast PA supply push

Renaissance Gas Transmission
Renaissance (2016)
Appalachian supply to Northern Georgia & Atlanta markets

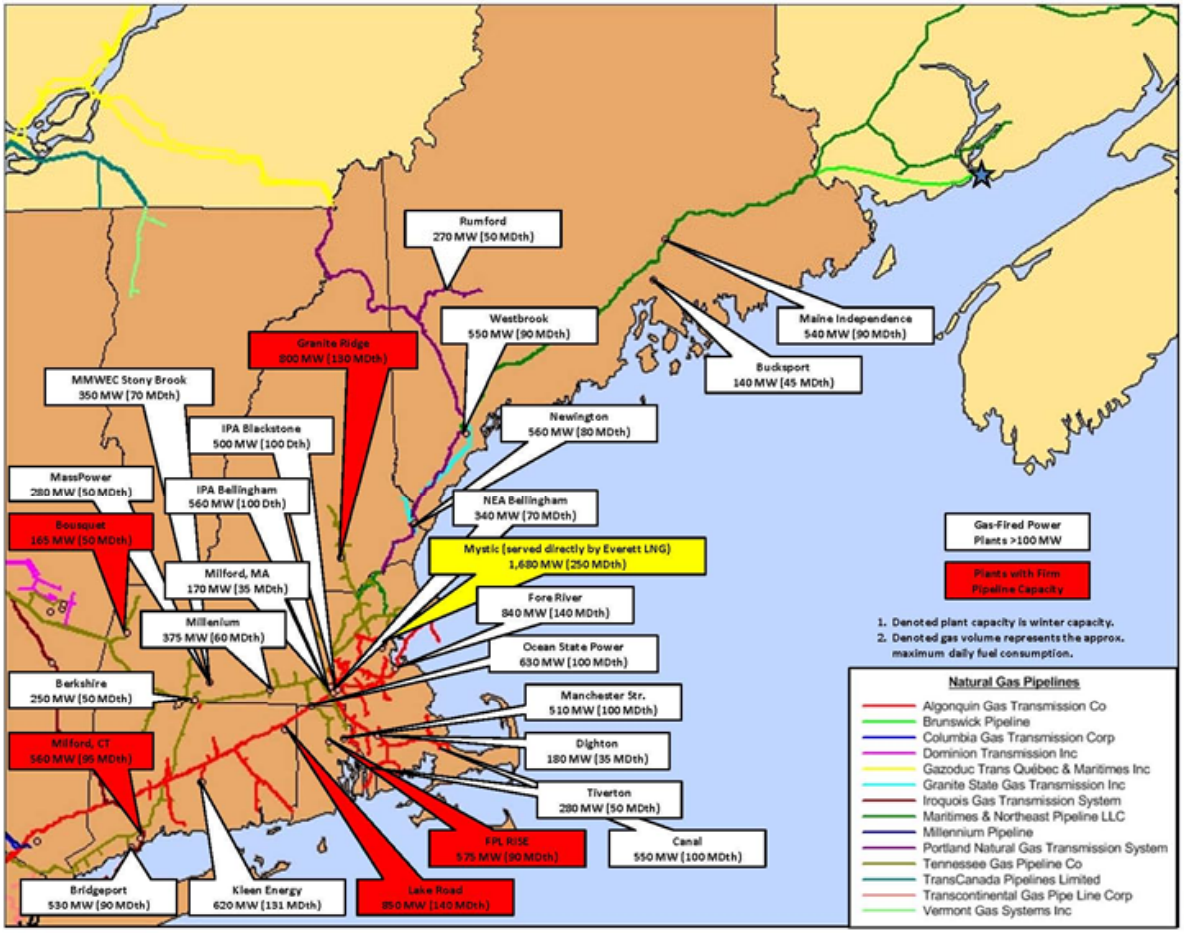
NEXUS Gas Transmission
NEXUS (2015/2016)
Providing Appalachian producers access to Eastern Canada LDC & power markets

Coordination with Gas Control

- Firm vs. Interruptible Service
  - Many generators have interruptible service
- Gas Day vs. Electric Day
  - Should we change the “batting order” in organized markets?
- Minimize surprises to the greatest degree possible
  - Sharing day ahead market results (and real time)
  - Training on how the electricity system works—system operations is somewhat predictable
- Provide real time consultation
  - Deciphering the (gas) EBB messages and (electric)emergency procedures messages

Firm vs. Interruptible Debate

New England Gas-fired Power Generation (>100 MW)



Many power plants are served on interruptible gas transportation service (except in the Southeast)

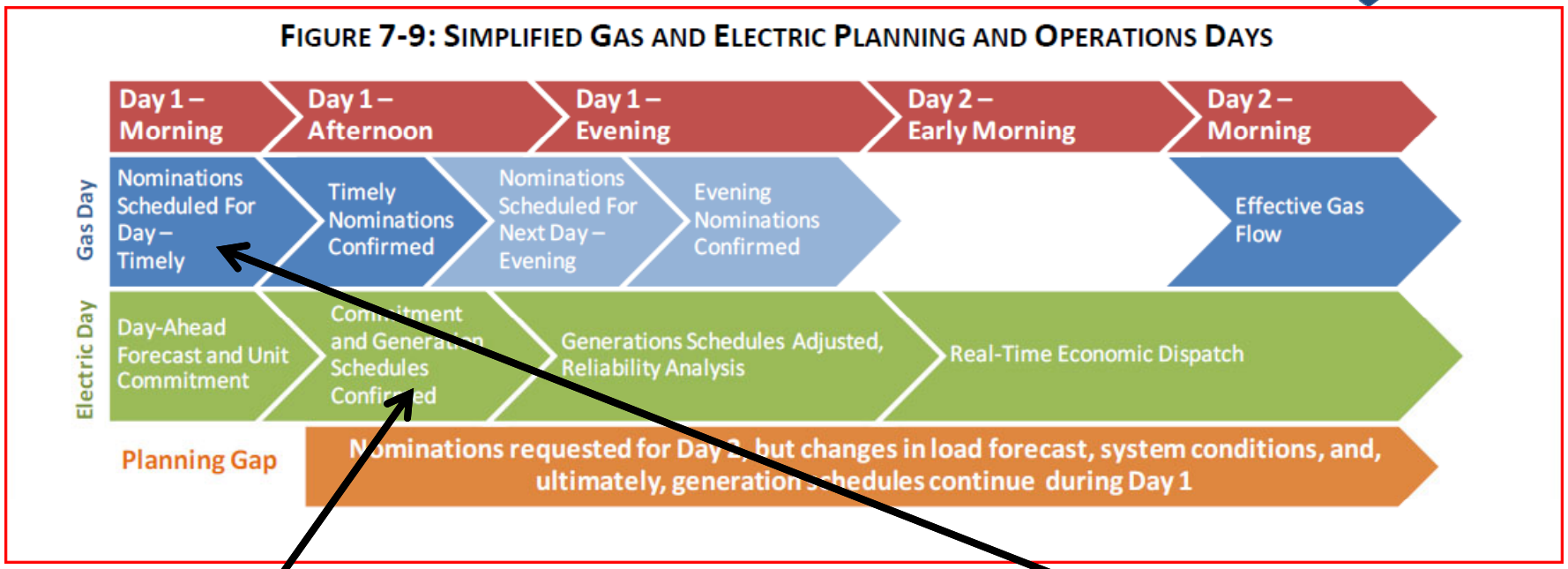
Legend: RED = Firm; WHITE = Interruptible

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What Can Electricity Do?

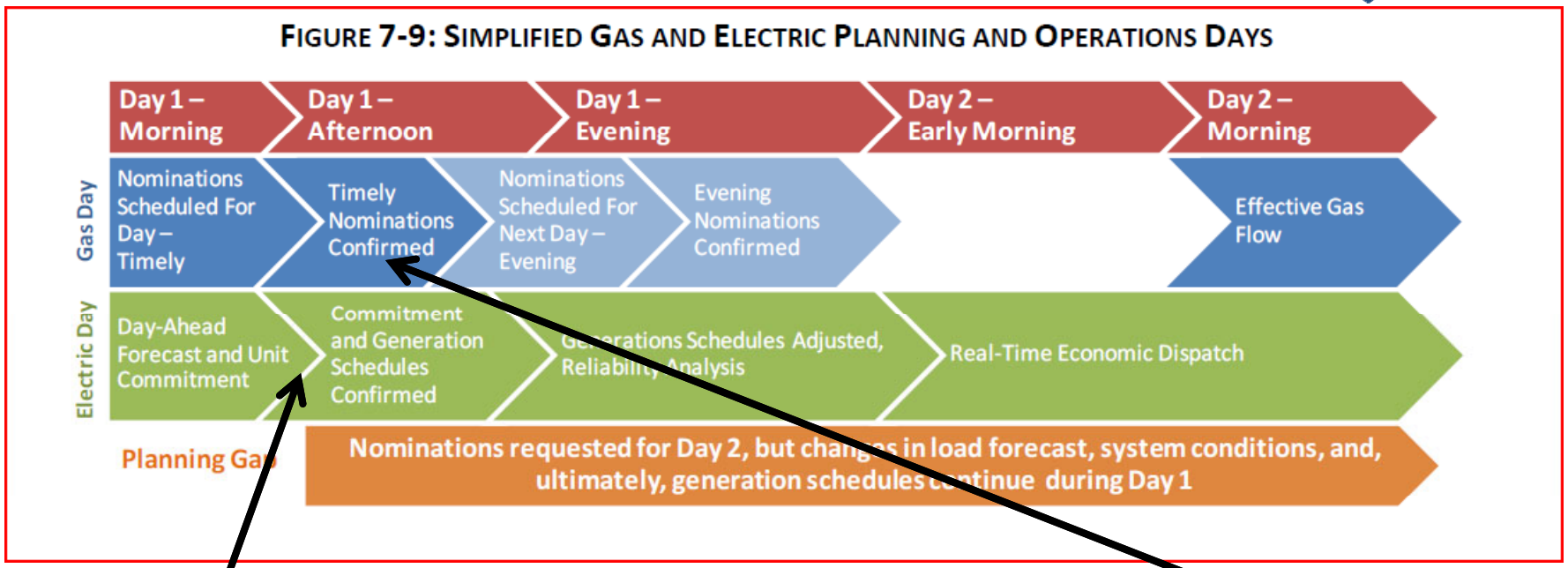
- Require generators to acquire firm service
  - Low capacity factor units cannot afford firm service
  - Reservation charges for firm service make these units uncompetitive in organized markets
- Placing limits on the use of quick starting generation
  - Recognition by the electric system operators that gas is a just-in-time fuel system that can only provide limited response in real time
  - Need for additional dual fuel capability
  - Use of hydro/pumped storage assets as other than economic energy providers

Gas Day vs. Electric Day



Issue: Timely gas nominations are due at 10AM the day before (Day 1); electric "awards" are made at 4PM the day before (Day 1) = 6 hours later; actual gas flow occurs starting at 10AM on Day 2

Gas Day vs. Electric Day SWITCH



Issue: Timely gas nominations are due at say 2PM the day before (Day 1); electric "awards" are made at say 12 Noon the day before (Day 1)

Result: Generators can provide a timely nomination and assure firm service delivery!

Summary

- Electricity is a “double edged sword” to the gas business
  - Largest growth market
  - Potential to cause problems in operations
- Working together, we can manage the operational problems
  - Awareness of the limitations on each side
  - More real time communications across the aisle
  - Maybe, rearrange the gas and electric days



Discussion

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Panel 4

Non-Traditional Threats

Cyber Threats and Sabotage - Mark Engels, Dominion

Geomagnetic Disturbance - Dr. Luis Marti, Hydro One

RELIABILITY | ACCOUNTABILITY






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Cyber Threats and Sabotage

Mark Engels, Dominion

November 28, 2012

RELIABILITY | ACCOUNTABILITY



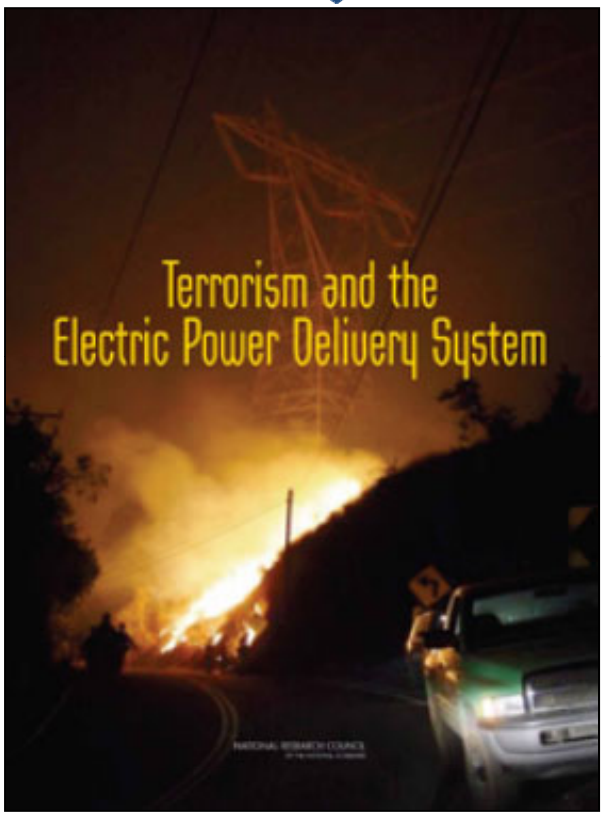



Public Media Attention

Disaster awaits U.S. power grid as cybersecurity lags

Cyber attackers could shut down the electric grid for the entire east coast

PENTAGON | JULY 27, 2012 | BY: ROBERT TILFORD



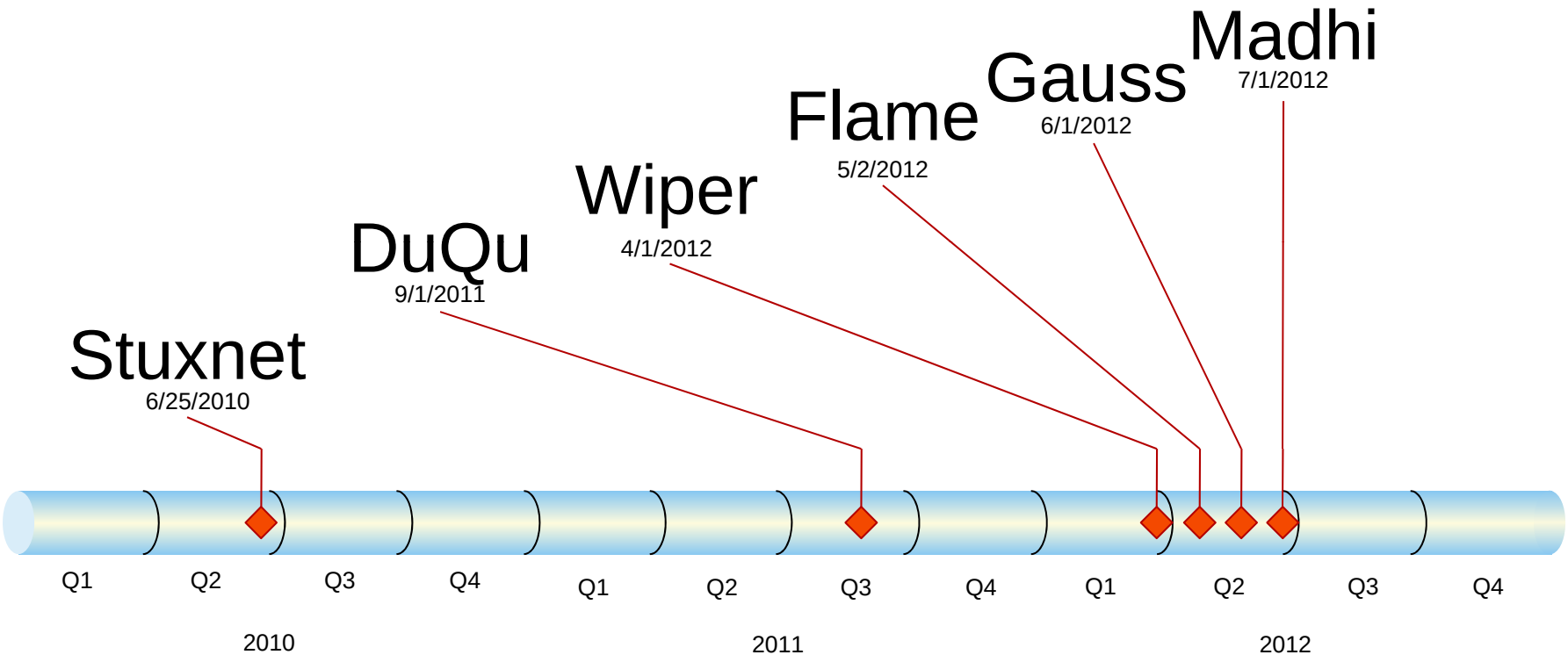
Thousands Seen Dying If Terrorists Attack U.S. Power Grid

By Brian Wingfield and Jeff Bliss – Nov 14, 2012 4:17 PM ET

Panetta Warns of Dire Threat of Cyberattack on U.S.

By ELISABETH BUMILLER and THOM SHANKER
Published: October 11, 2012

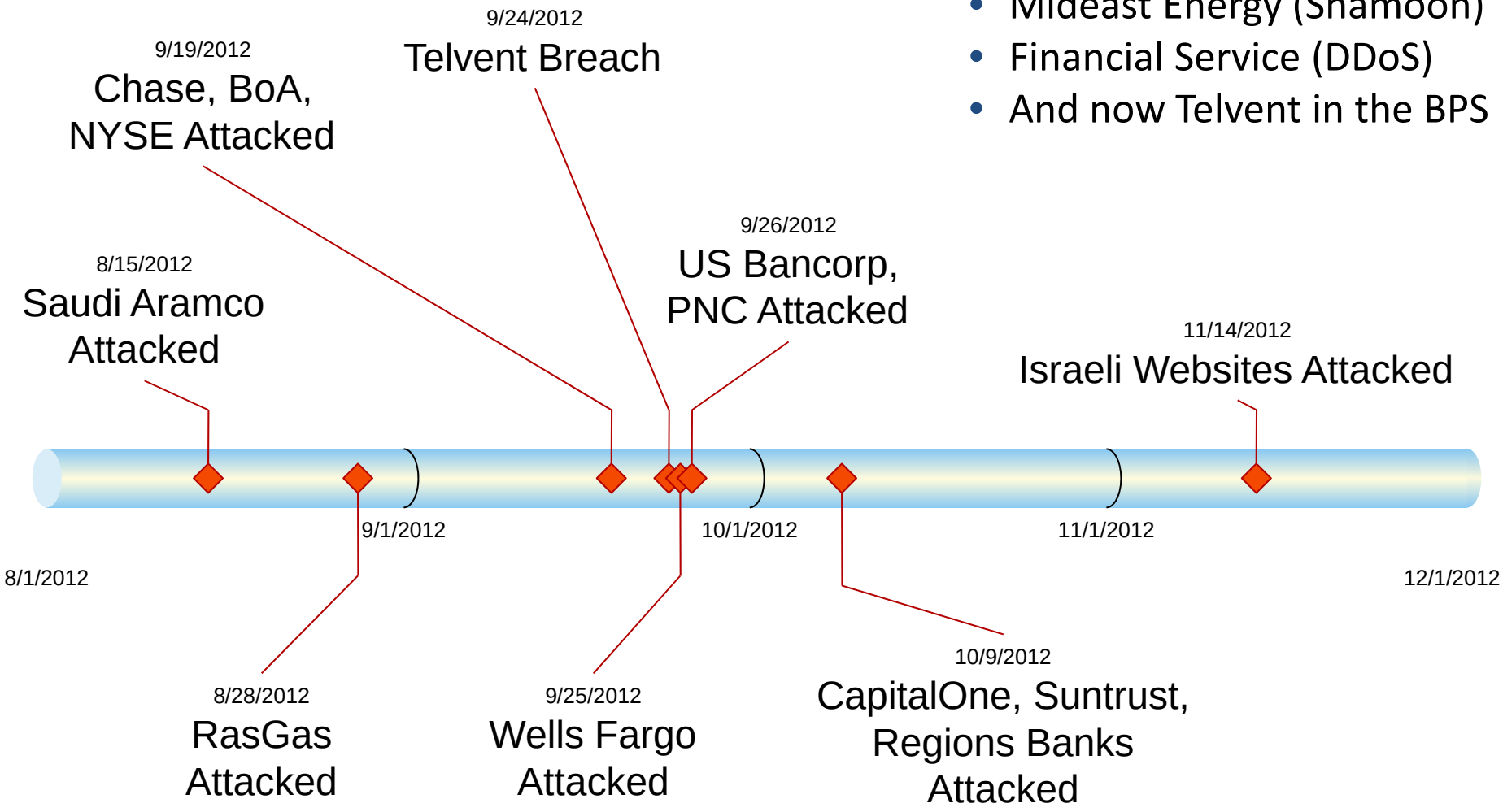
Cyber Landscape



Discoveries - Q1 2010 to Q2 2012

Cyber Landscape

- Mideast Energy (Shamoon)
- Financial Service (DDoS)
- And now Telvent in the BPS



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Industrial Control System Vulnerabilities

Hoping to Teach a Lesson, Researchers Release Exploits for Critical Infrastructure Software

MIAMI, Florida – A group of researchers has discovered serious security holes in six top industrial control systems used in critical infrastructure and manufacturing facilities and, thanks to exploit modules they released on Thursday, have also made it easy for hackers to attack the systems before they're patched or taken offline.

ICS-CERT
INDUSTRIAL CONTROL SYSTEMS CYBER EMERGENCY RESPONSE TEAM
CONTROL SYSTEMS SECURITY PROGRAM

ICS-CERT ALERT

ICS-ALERT-12-020-01—S4 DISCLOSURE OF MULTIPLE PLC VULNERABILITIES IN MAJOR ICS VENDORS

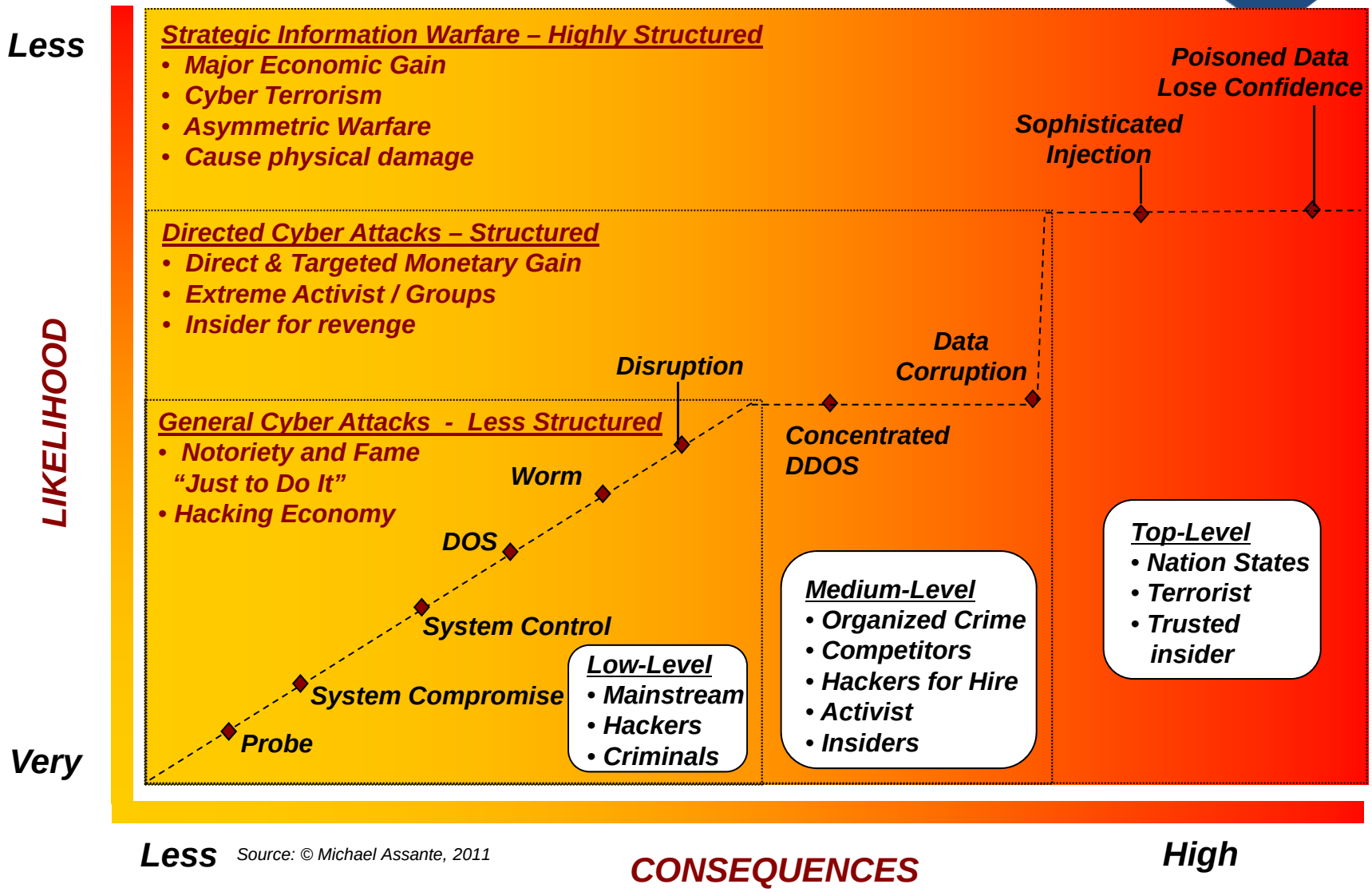
January 20, 2012

Affected Vendors	Product
General Electric	D20/D20ME
Rockwell Automation	Allen Bradley ControlLogix
Rockwell Automation	Allen-Bradley MicroLogix
Schneider Electric	Modicum Quantum
Koyo	Direct LOGIC H4-ES
Schweitzer	SEL-2032

	A-B	Schneider Electric	GE	SEL	Koyo
Firmware	!	✗	!	!	!
Ladder Logic	!	!	✗	!	✗
Back Doors	!	✗	✗	✓	✓
Fuzzing	✗	✗	✗	!	!
Web	!	✗	N/A	N/A	✗
Basic Config	!	!	✗	!	!
Exhaustion	✓	✓	✗	✓	✓
Undoc Features	!	✗	✗	!	!

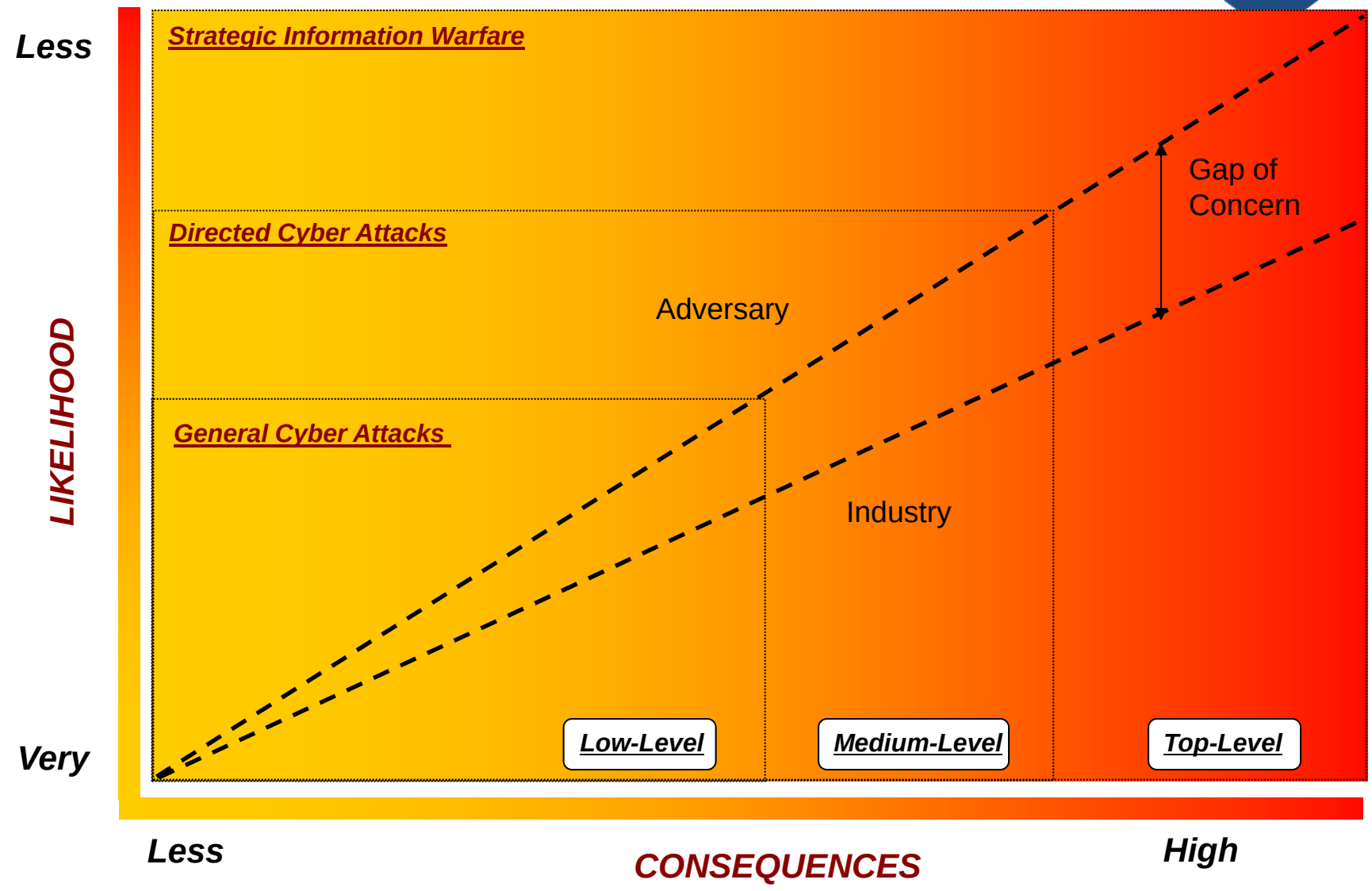
Chart listing the vulnerability types found in PLCs the researchers examined. A red "x" indicates the vulnerability is present in the system and is easily exploited; a yellow exclamation point indicates the vulnerability exists but is difficult to exploit; the green checkmark indicates the system lacks this vulnerability.

Adversaries and Capabilities



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Industry versus Adversary Capability and Response



What Does "Take Down the Grid" Mean?

1 — Local Impact

- Single Utility
- Single State
- Local trans and dist
- Up to 1 million customers

June 29, 2012 *- One million customers out in Virginia*

2 — State Impact

- 1-2 Utilities
- 1-3 States
- 1 Reliability Coordinator
- 1-5 million Customers

Feb 25, 2008 *- Up to 3 million people — about a fifth of Florida's population lost power.*

Sept 8, 2011 *- Power outage knocked out electricity to up to 5 million people in California, Arizona and Mexico.*

3 — Regional Impact

- 3-5 Utilities
- 4 -10 States
- 2-3 Reliability Coordinators
- 5-50 Million Customers

Aug 14, 2003 *- East Coast Blackout affecting 40 - 50 million people in eight U.S. states and Canada.*

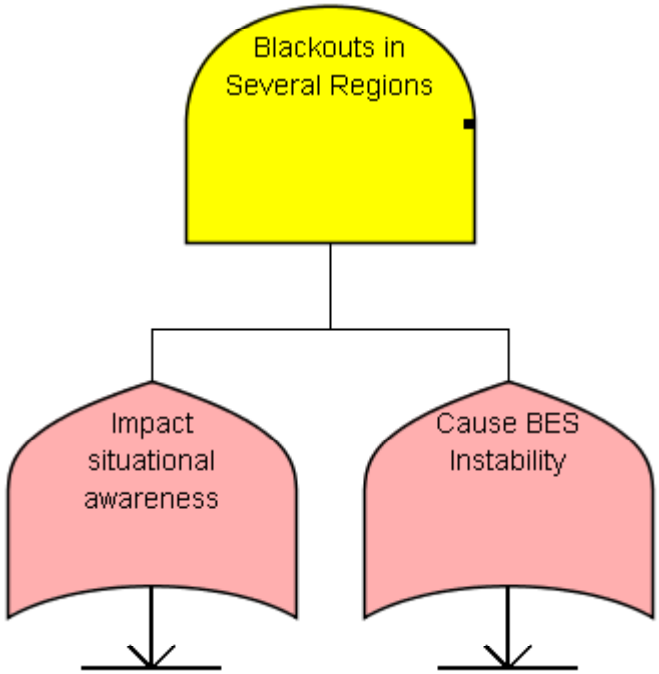
October 29, 2012 *- 8-9 million customers in 18 states*

4 — National Impact

- More than 5 Utilities
- More than 10 States
- More than 3 Reliability Coordinators
- More than 50 Million Customers

July 31, 2012 *- India's interconnected power grids failed, leaving 600 million people — half the population — without electricity.*

Scenario – Blackouts in Several Regions



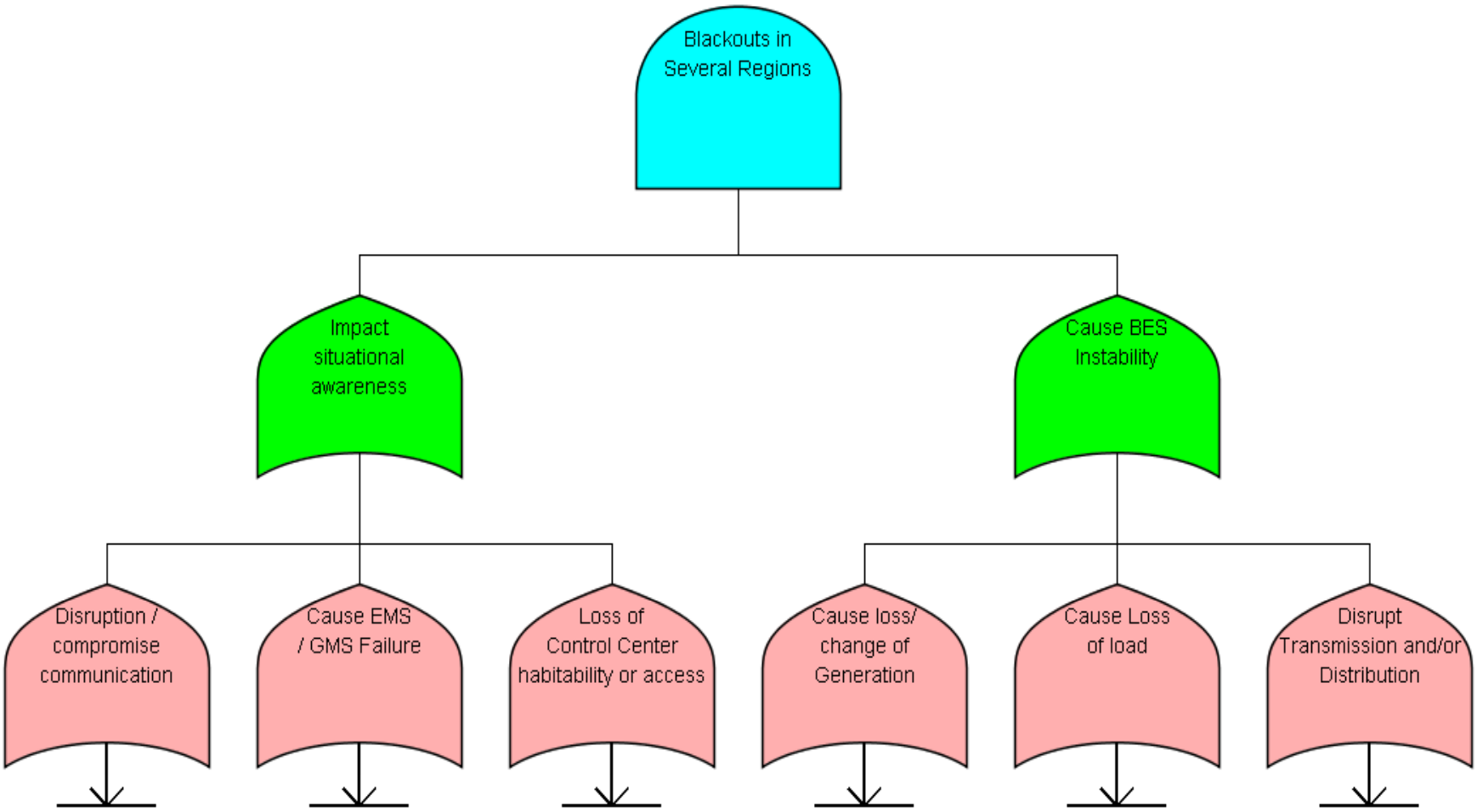
1. ***Transmission Operators report unexplained and persistent breaker operation*** *that occurs across a wide geographic area (i.e. within state/province and neighboring state/province) (Cause BES Instability)*

2. ***Communications are disrupted and disables Transmission Operator voice and data*** *with half their neighbors, their Reliability Coordinator, and Balancing Authority (Impact Situational Awareness)*

3. ***Loss of load and generation causes widespread BPS instability****, and system collapse within state/province and neighboring state/province. Portions of the grid remain operational. (Cause BES Instability)*

4. ***Blackouts in several regions*** *disrupt distribution supply to several million people. (Attack Result)*

Scenario – Blackouts in Several Regions



NERC Cybersecurity Standards

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2004 - 2005
Urgent Action Standard 1200

2006 - 2009
CIP002 – CIP009 version 1

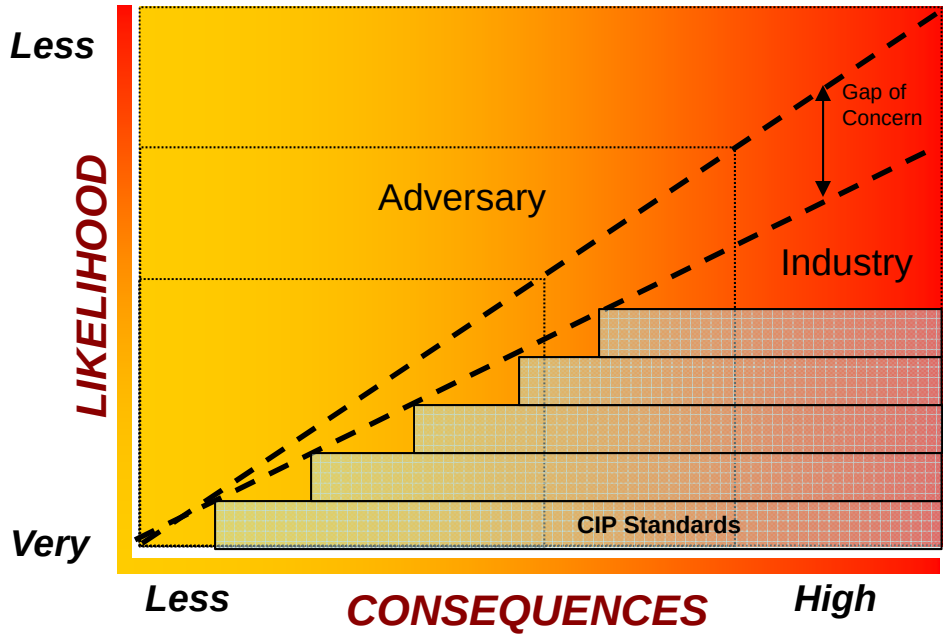
2010 April
CIP002 – CIP009 version 2

2010 October
CIP002 – CIP009 version 3

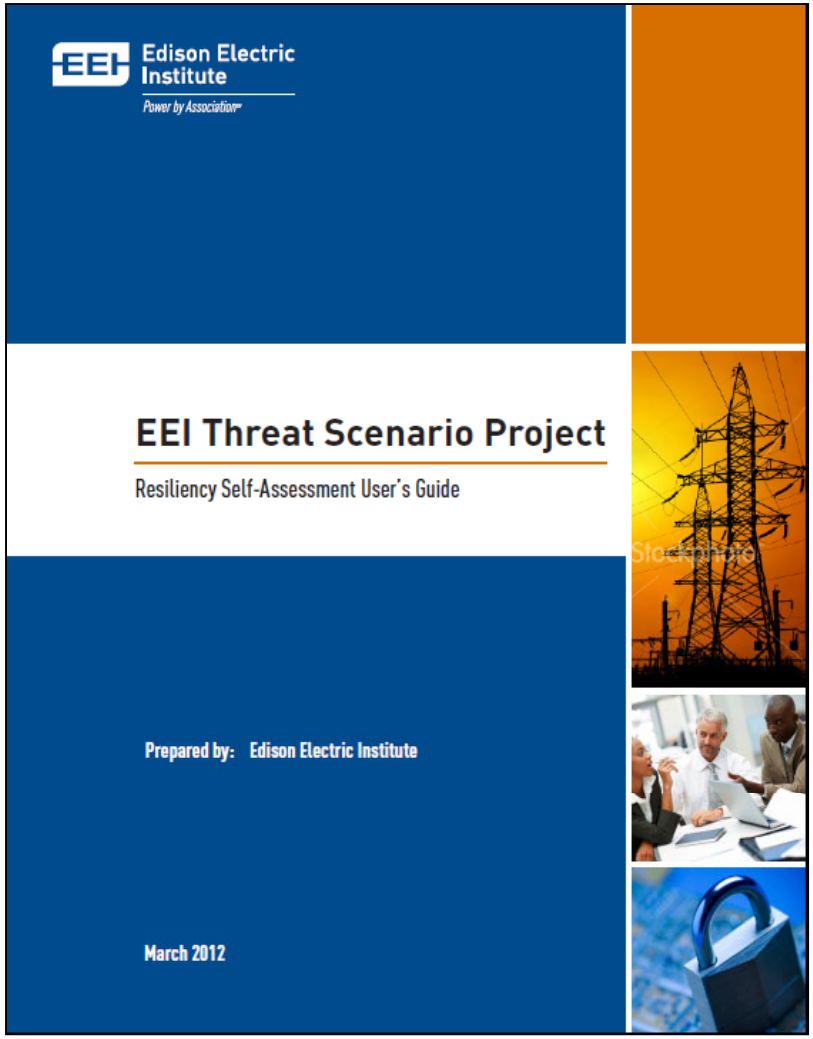
2011
CIP002 – CIP009 version 4

2011 – 2013
CIP002 – CIP011 version 5

Utilities are currently under NERC CIP Version 3, but have been required to comply with cyber security standards since 2004.



EEI Threat Scenario Assignment

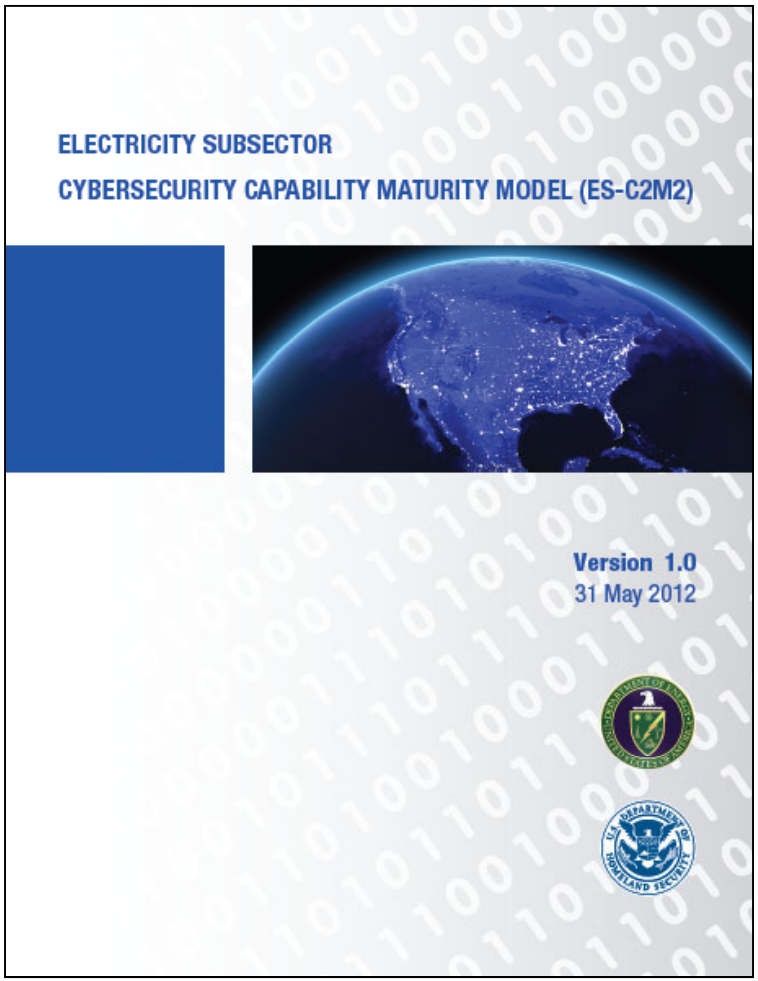


Member companies worked with The Chertoff Group to develop mitigation actions for top industry threats

- Coordinated Cyber Attack
- Advanced Persistent Threat
- Disruption of Voice and Data Services
- Coordinated Physical and Cyber Attack
- Insider Sabotage
- Pandemic
- Supply Chain Disruption or Compromise
- Catastrophic Human Error
- Intentional Electromagnetic Interference

Conducted self-assessments based on threats and mitigation measures.

DOE/DHS Electricity Subsector Cybersecurity Capability Maturity Model

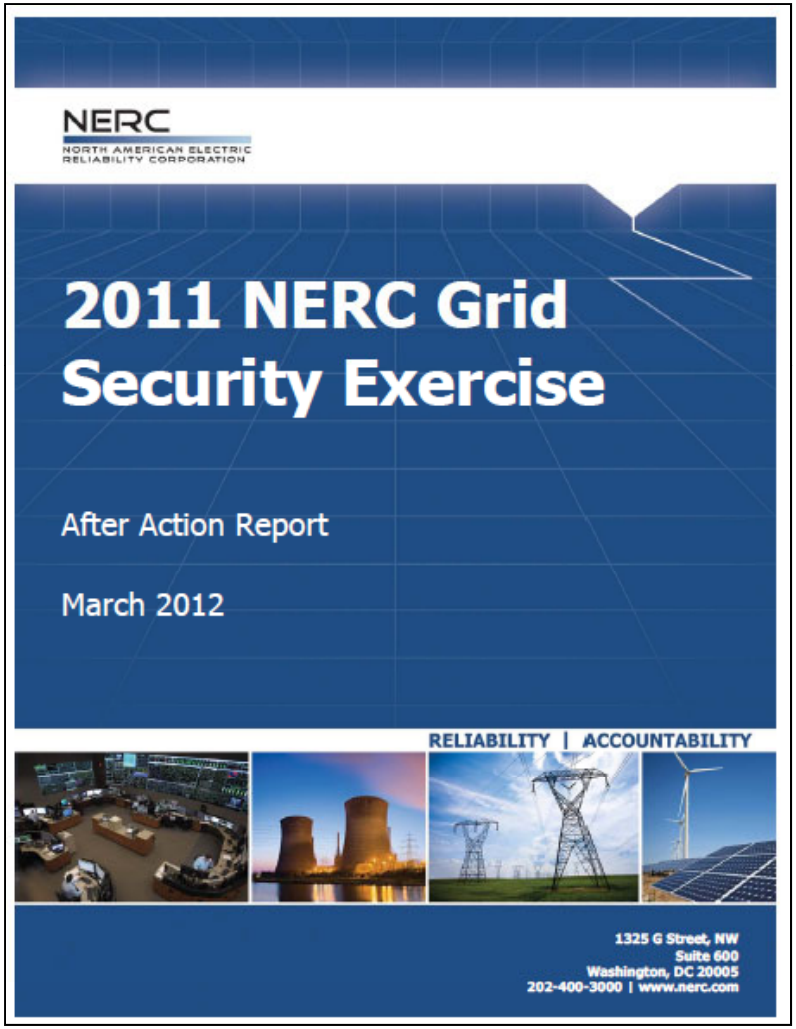


Approximately 20 companies (Investor Owned Utilities, Coops and Munis) participated in the pilot.

Domains in maturity model in which companies are evaluated:

1. Asset, Change, and Configuration Management (ASSET)
2. Workforce Management (WORKFORCE)
3. Identity and Access Management (ACCESS)
4. Risk Management (RISK)
5. Supply Chain and External Dependencies Management (DEPENDENCIES)
6. Threat and Vulnerability Management (THREAT)
7. Event and Incident Response, Continuity of Operations (RESPONSE)
8. Situational Awareness (SITUATION)
9. Information Sharing and Communications (SHARING)
10. Cybersecurity Program Management (CYBER)

NERC Secure Grid Exercise



GridEx 2011 - Sector-wide grid security exercise conducted on November 16-17, 2011

Validate readiness of the Electricity sub-sector to respond to a cyber incident, strengthen utilities' crisis responses functions and provide input for internal security program improvements

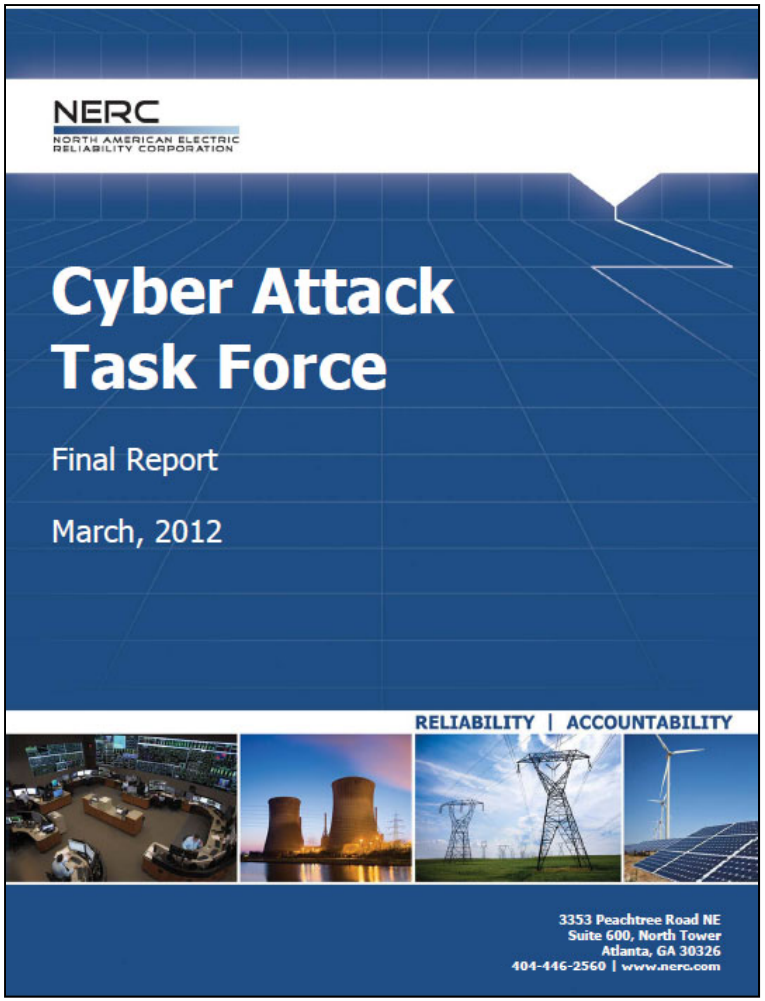
Seventy-five industry and government organizations from the U.S. and Canada participated

Industry included generation and transmission owners, reliability coordinators, independent system operators and balancing authorities

Exercise involved internal response measures and external coordination activities across the sector

After-action report produced

NERC Cyber Attack Task Force



Outgrowth from the Critical Infrastructure Strategic Roadmap and High Impact Low Frequency efforts

The primary intent of the CATF is to consider the impact of a coordinated cyber attack on the operation of the bulk power system, and to develop flexible options for detecting, operating and recovering

TF recommended solutions for broad implementation across the electricity industry

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CATF Recommendations

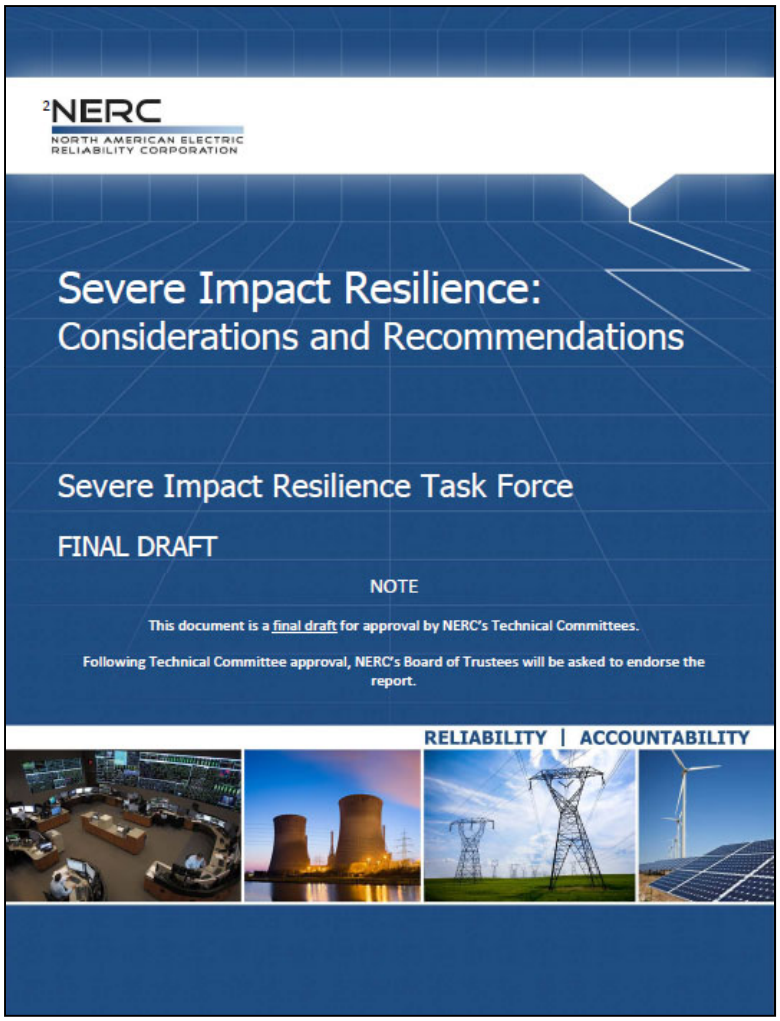
Recommendation	Resilience Contribution		
	Prevent Deter	Detect	Respond
Continue work on "Attack Trees"	✔		
Continue to develop security and operations staff skills to address increasingly sophisticated cyber threats	✔	✔	
Augment operator training with cyber attack scenarios		✔	✔
Conservative operations		✔	✔
Conduct transmission planning exercise	✔		✔

CATF Recommendations

Recommendation	Resilience Contribution
Endorse NERC initiatives that help entities prepare/respond to a cyber attack	Prevent Deter: ✔ / Detect: / Respond: ✔
Increase awareness of Department of Energy initiatives	Prevent Deter: ✔ / Detect: / Respond:
Continue to extend public / private partnership	Prevent Deter: / Detect: / Respond: ✔

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NERC Severe Impact Resilience Task Force



The purpose of the SIRTF is to provide guidance and options to enhance the resilience of the bulk power system to withstand and recover from severe-impact scenarios, specifically:

- Coordinated physical attack
- Coordinated cyber attack
- Geomagnetic disturbance

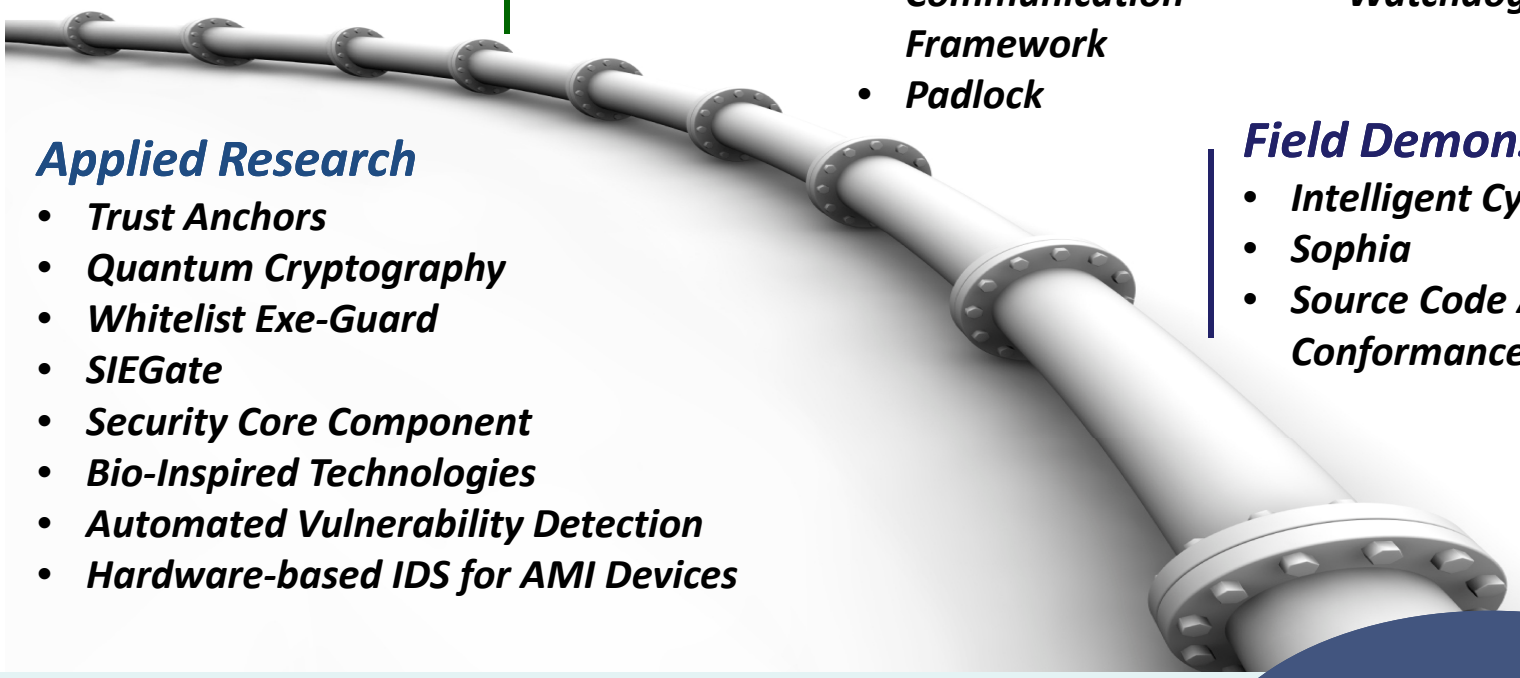
The SIRTF has considered what aspects of emergency operation and restoration would be particularly challenged through a Severe Event and considered options to enhance the resilience of the Bulk Power System

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DOE Cybersecurity Electricity Delivery Systems Technology Readiness

Prototype Development

- *Data Fusion*
- *GridStat Middleware Communication Framework*
- *Padlock*
- *RBAC Driven Least Privilege Architecture*
- *Watchdog*



Applied Research

- *Trust Anchors*
- *Quantum Cryptography*
- *Whitelist Exe-Guard*
- *SIEGate*
- *Security Core Component*
- *Bio-Inspired Technologies*
- *Automated Vulnerability Detection*
- *Hardware-based IDS for AMI Devices*

Field Demonstration

- *Intelligent Cyber Sensor*
- *Sophia*
- *Source Code Analysis and Conformance Testing*

CEDS projects engage national labs, vendors, asset owners, and academia throughout the project lifecycle to deliver relevant projects with clear commercialization paths.

Commercial Products

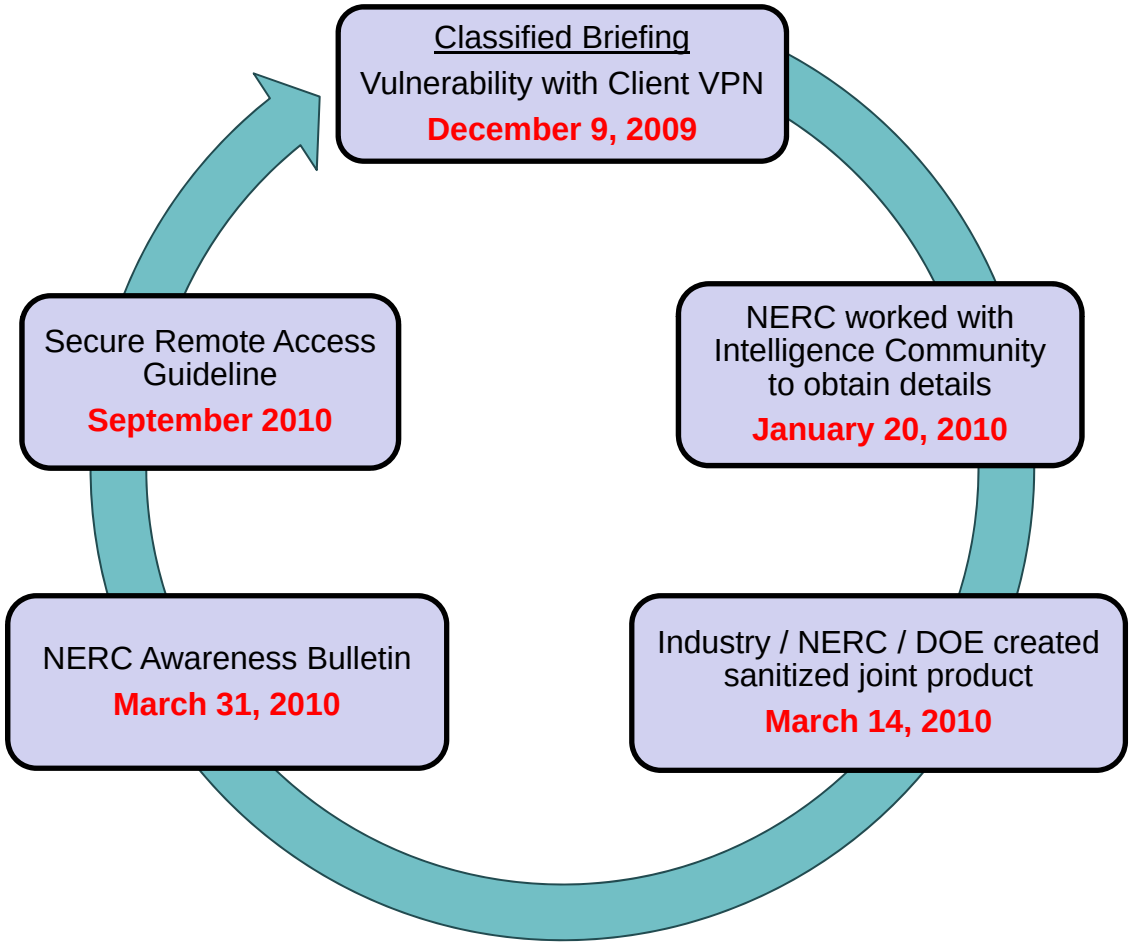
Secure serial links

Optimal security configuration

Interoperable secure communications

Addressing the Gap

Information Sharing - Public / Private Partnership

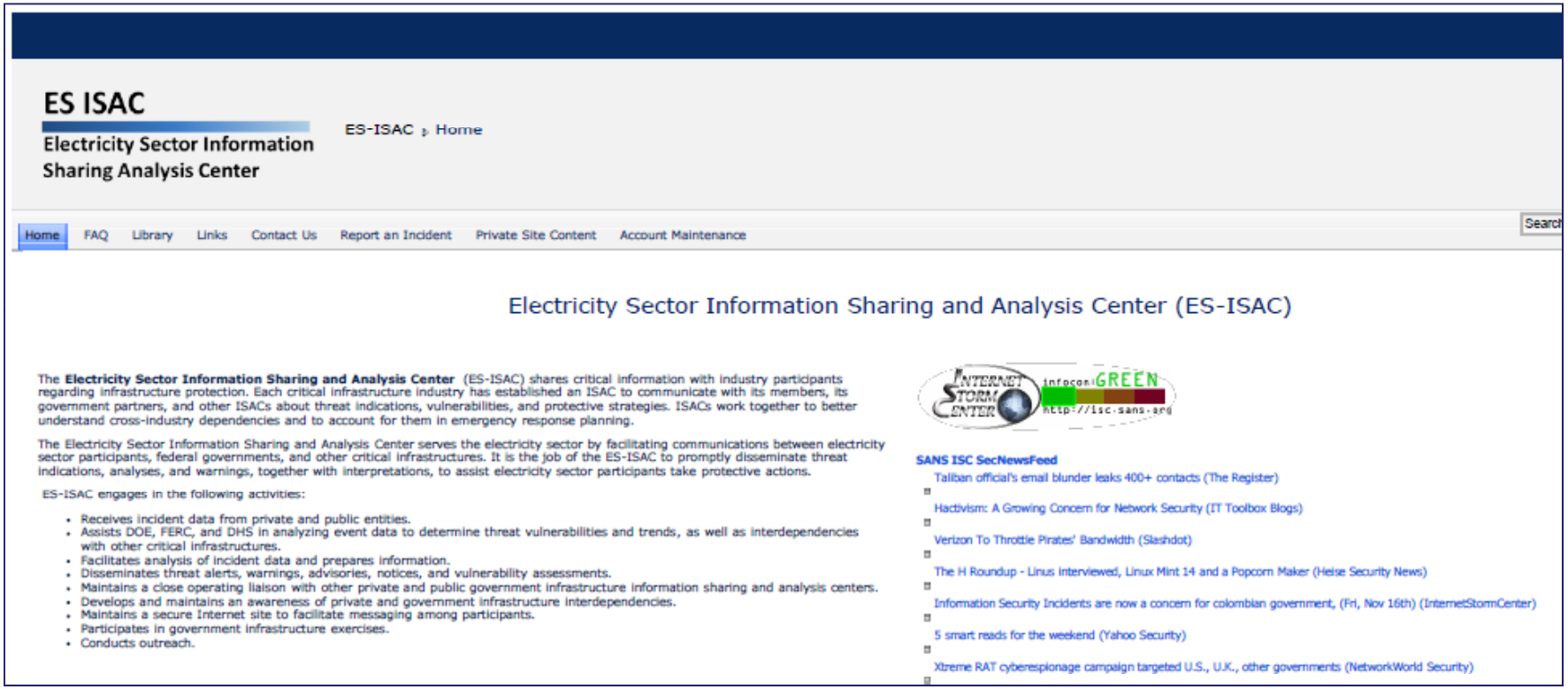


Case Study for information sharing in the public / private partnership

For immediate action and potentially eminent threats, a different method must be used

Addressing the Gap

Electricity Sector Information Sharing Analysis Center



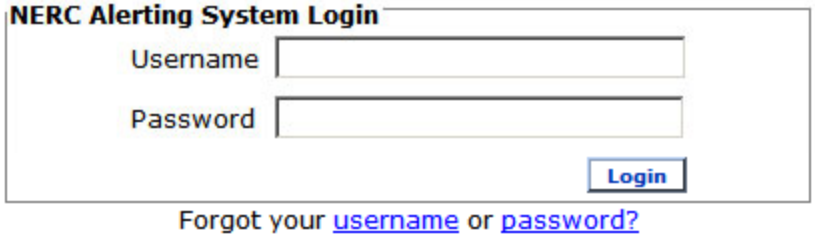
The Electricity Sector Information Sharing Analysis Center (ES-ISAC) is key portal for asset owners and operators to obtain information related to sector threats/vulnerabilities.

Addressing the Gap

NERC Alert System



ALERT TYPE	HANDLING
Industry Advisory	Public
Recommendation to the Industry	Private
Essential Action Notifications	Sensitive
	Confidential





The NERC Alert System is one method of communicating sensitive and actionable information to the industry in an expedited manner.

- ESISAC staff, industry, vendor and government SMEs (Hydra Team) develop alert and mitigation steps
- Recommendations and Essential Action alerts require industry response plan

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Geomagnetic Disturbances

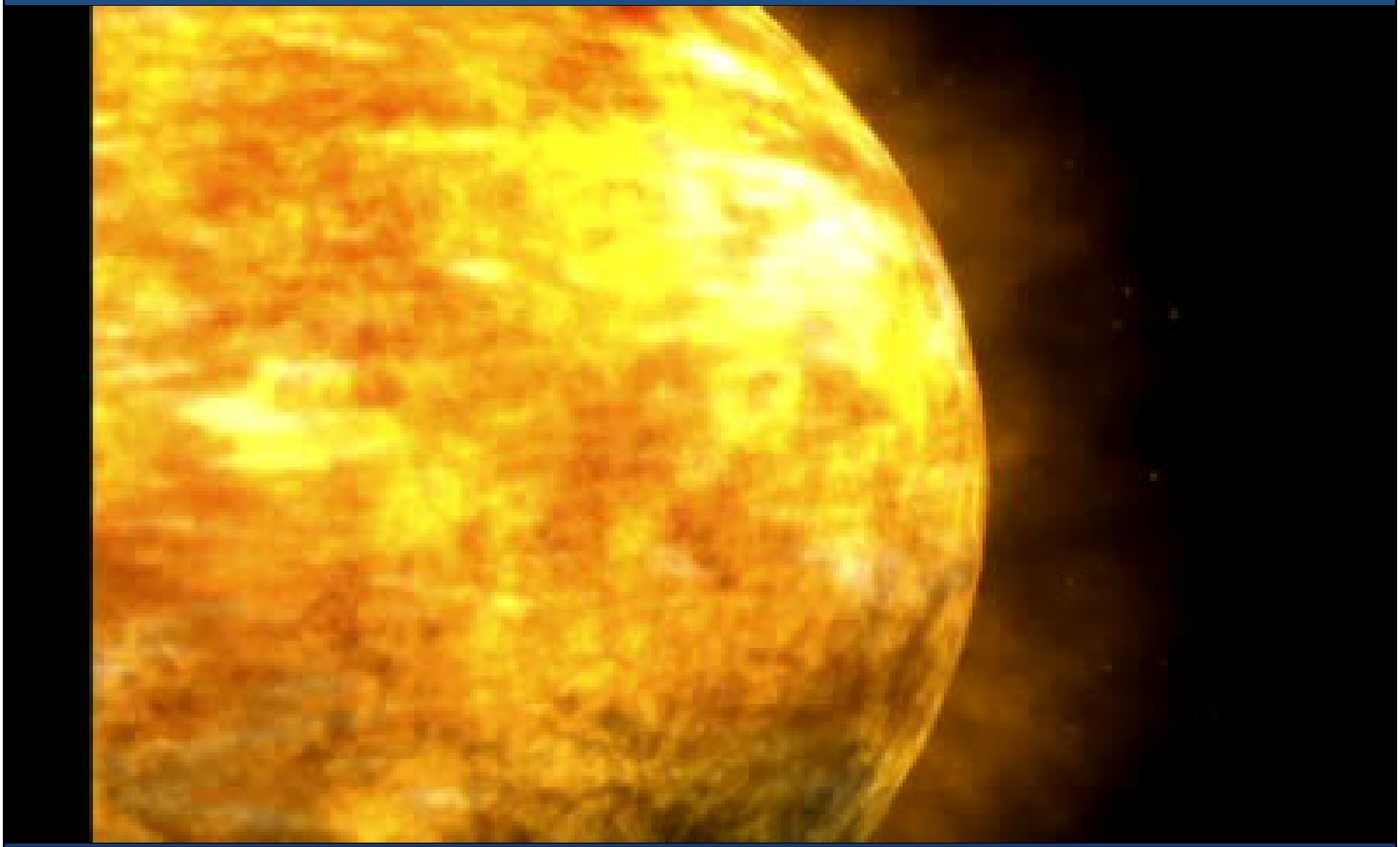
Dr. Luis Marti, Hydro One

November 28, 2012

RELIABILITY | ACCOUNTABILITY





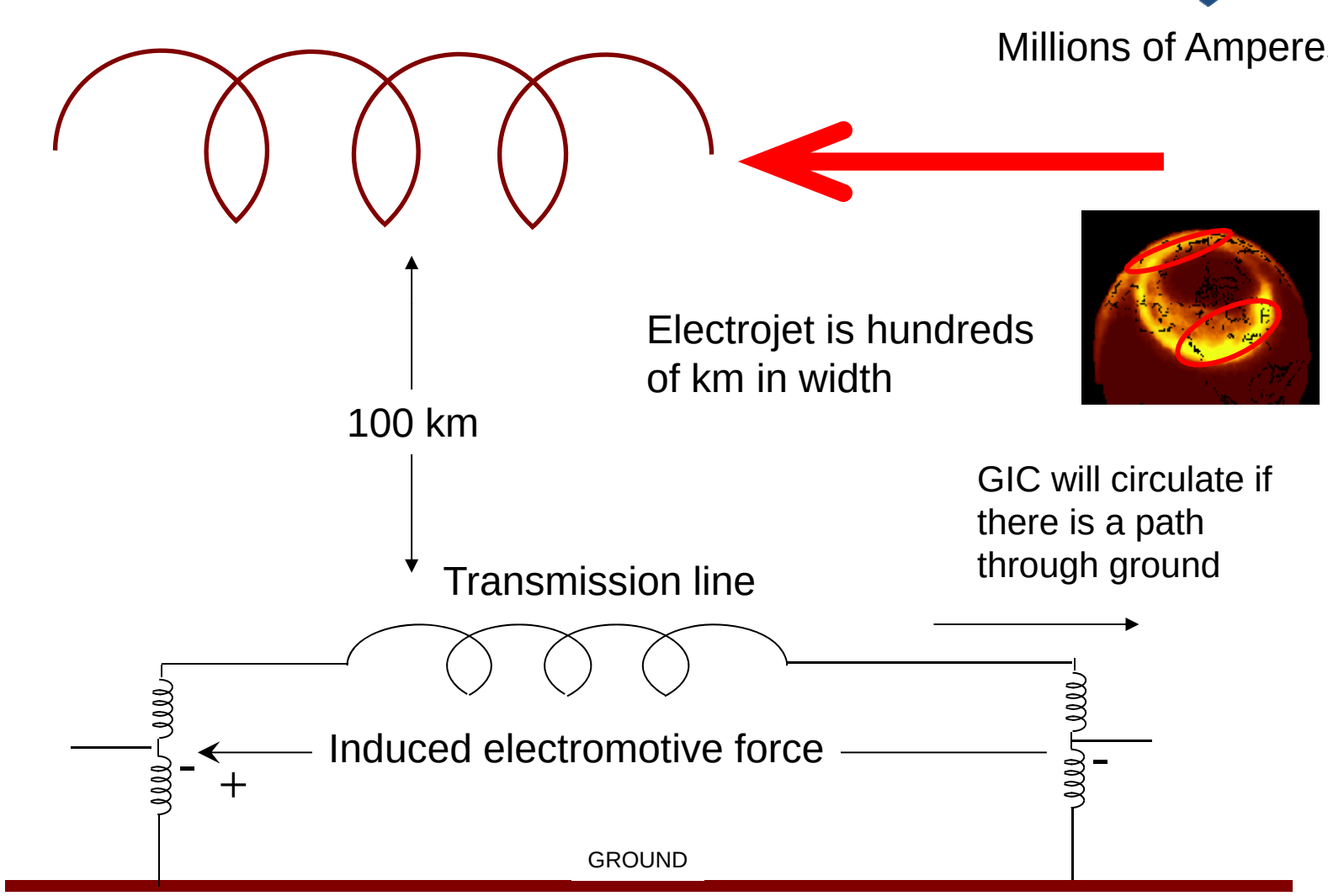



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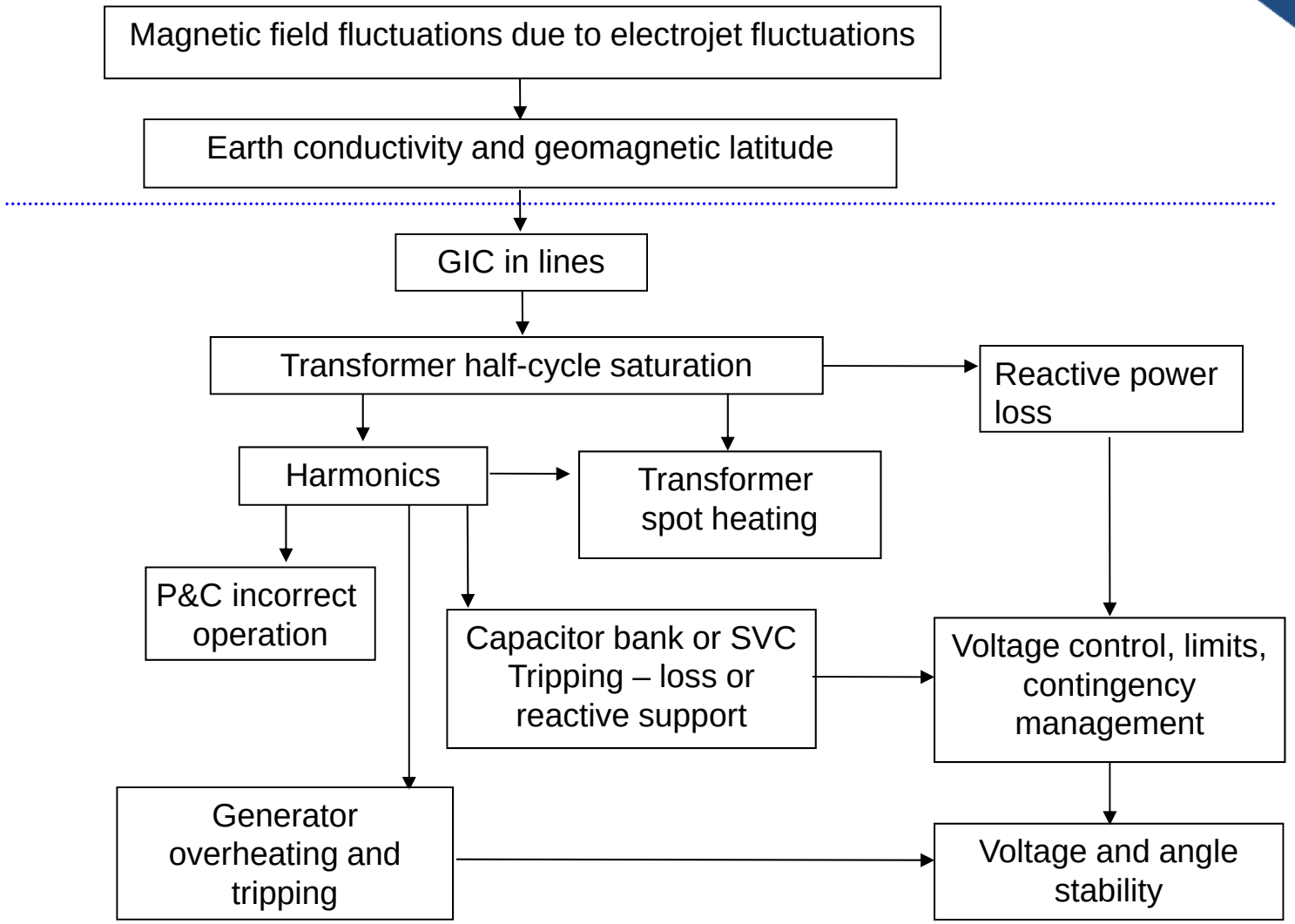
A CME has arrived

- Fluctuations in the electrojet current induce geoelectric potentials
- If there is a closed path through grounded transformers Geomagnetically Induced Currents (GIC) will circulate
- Frequency of GIC ranges from 1 to 100 mHz
- Geographically broad effects
- Number and magnitude of CMEs tend to be higher during the solar max every 11 years or so

GIC and the Power System



Effects of GIC



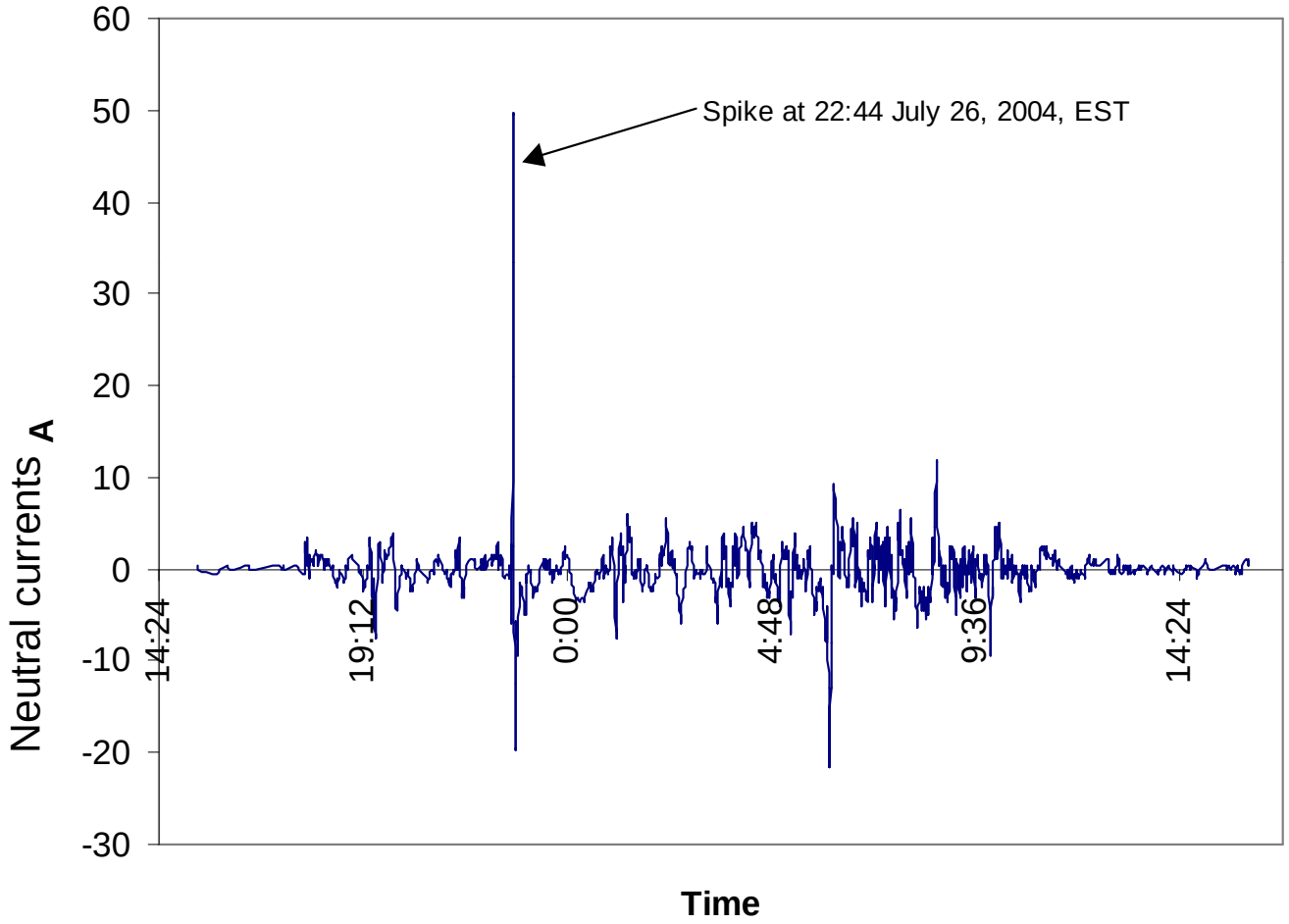
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And all that means…

- An extreme event can affect the balance of reactive power in the HV network
- If not recognized and addressed, an extreme event can lead to
  - Voltage collapse and blackout
  - Localized damage of vulnerable equipment

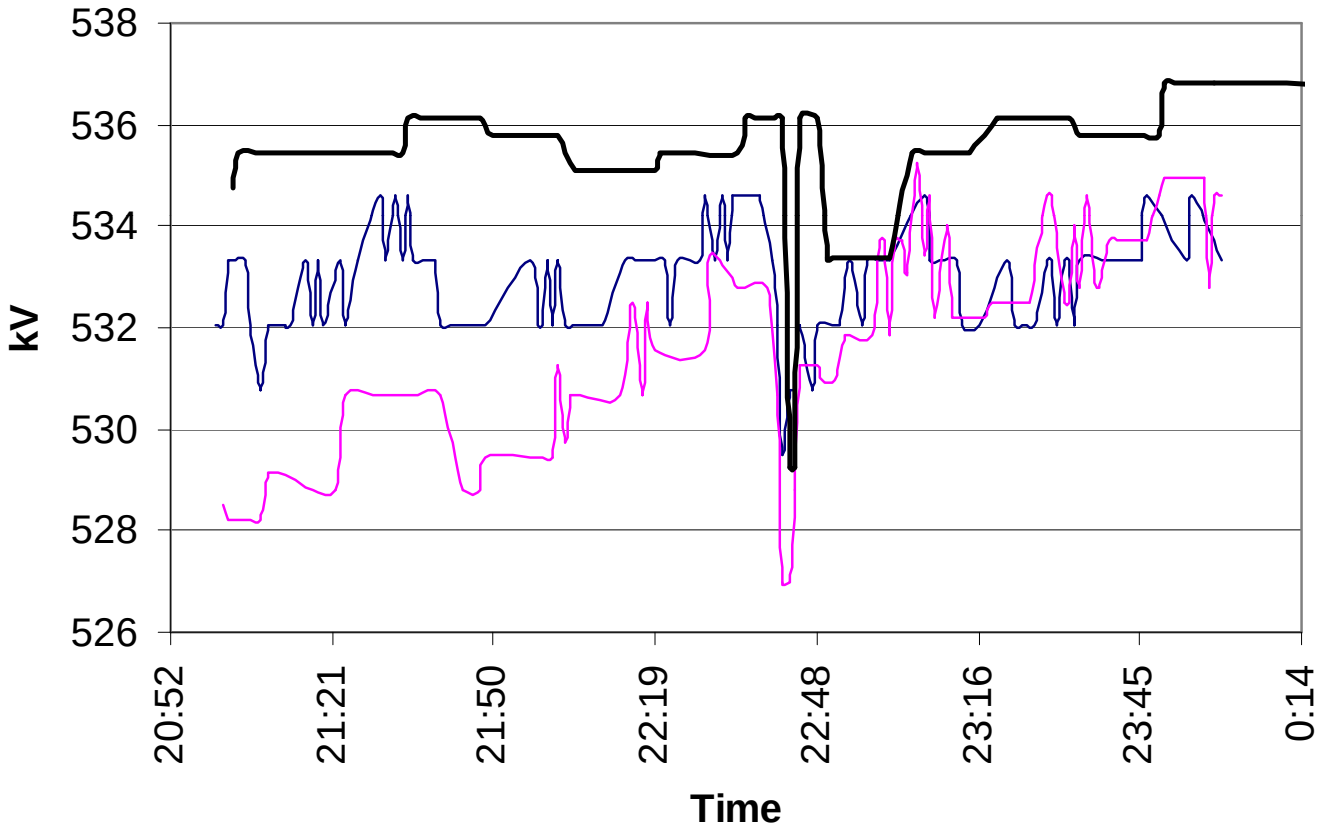
A minor event in 2004

July 26-27, 2004



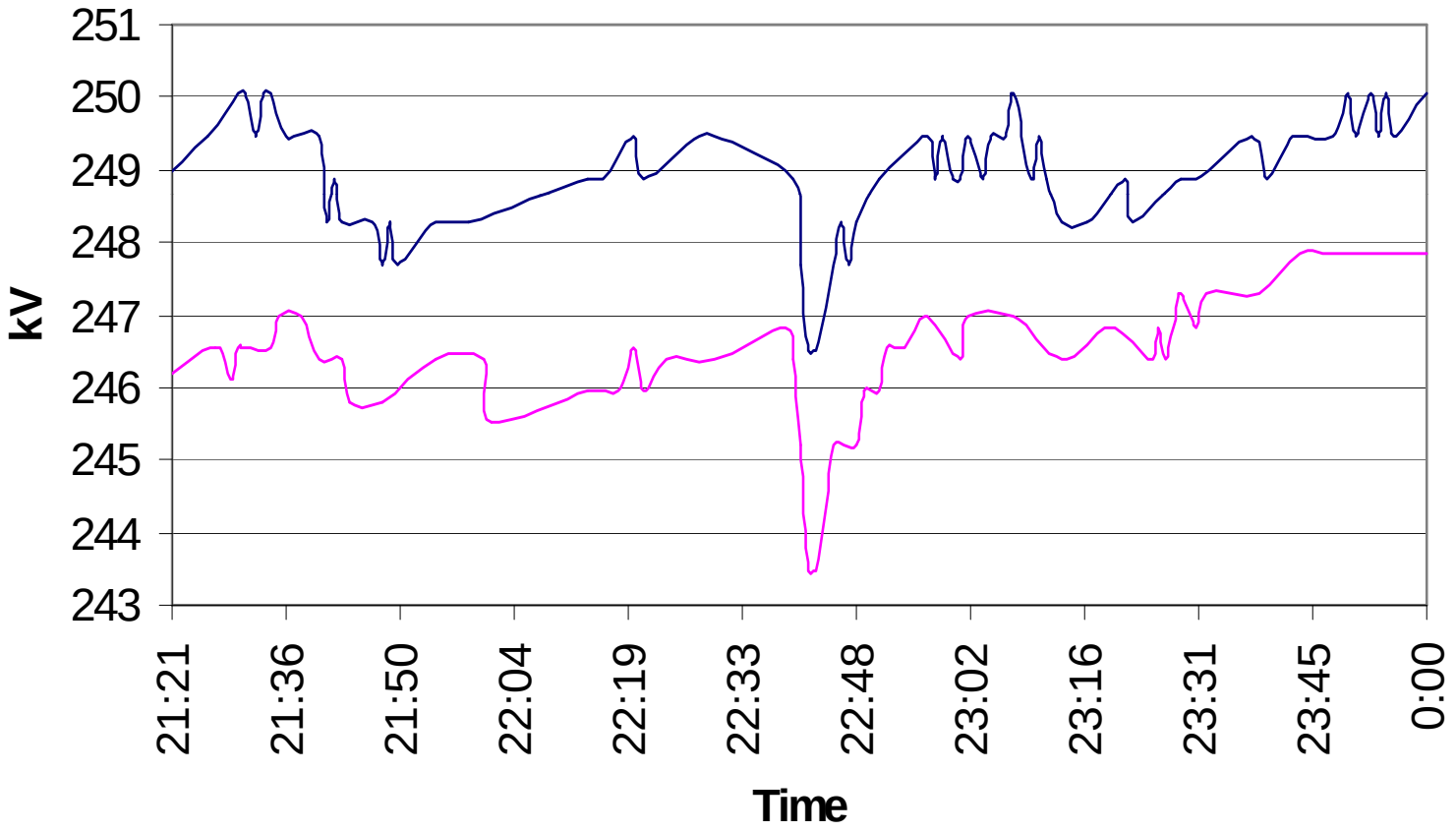
A minor event in 2004

500kV voltage responses



A minor event in 2004

230kV voltage responses



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Are these things real?

- March 13 1989 – Hydro Quebec blackout occurred in less than a minute and lasted for 8 hours
- Nuclear station step-up transformer failed in PJM
- Storm intensity peaked at 2-3 V/km in Ontario
- Carrington event in 1859 sometimes estimated as being 10 times worse than the March 1989 event

- An extreme CME occurred in July 14 2012, but it missed earth

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Is GMD a new threat?

- The effects of GMD in the HV power system is an engineering problem
- Generally those folk closer to the electrojets have paid more attention to the issue
- In the last few years the topic has received an unprecedented amount of attention
- NERC created the GMDTF in 2011
  - Interim report in February 28 2012
  - GMDTF 2.0 is acting on the recommendations of the report
  - Work will continue through 2013

Learning more about GMD

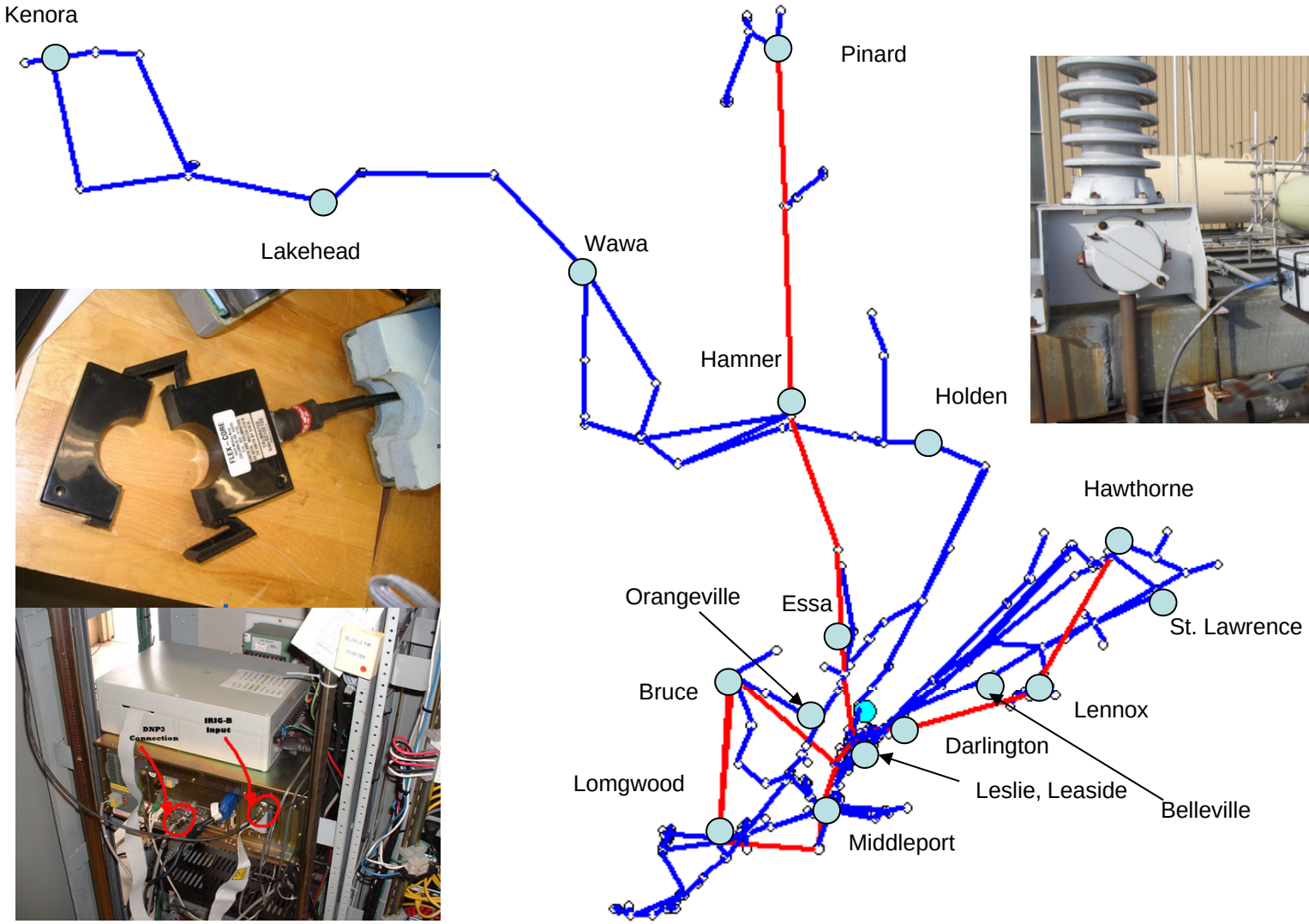
- A positive side of the newly found notoriety is that more brain power is being devoted to the problem
- Research institutes and learned societies are devoting more resources
  - NASA/NOOA/NRCan
  - EPRI
  - IEEE
  - CIGRE
- Transformer manufacturers are being engaged in the process – key factor in modeling

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What has Ontario done?

- Multiple studies of GIC and its effects on the Ontario power system since the mid 80s (before the 1989 Hydro Quebec blackout)
- Cooperative work between engineers and geophysicists
- Funded University research
- In this cycle, activities have stepped up
  - More GIC monitoring equipment
  - Equipment to also measure the effects of GIC (harmonics, hot spot heating)
  - New real-time storm tracking/management tool in the control centre
  - Innovation in modeling and training

2013 GIC detection network





Real time GMD management

- Real-time analysis/display tool to show GIC calculated from 1 s magnetic field measurements.
  - Dynamic network configuration: around 530 HV transformers, 800 500 kV and 230 kV circuits, and 30 shunt capacitor banks
  - GIC in every transformer, circuit and station
  - Transformer hot spot temperature, var loss, harmonics
  - Capacitor bank harmonic current
  - Control room alarms
    - Transformer hot spot temperature
    - Capacitor bank harmonic currents

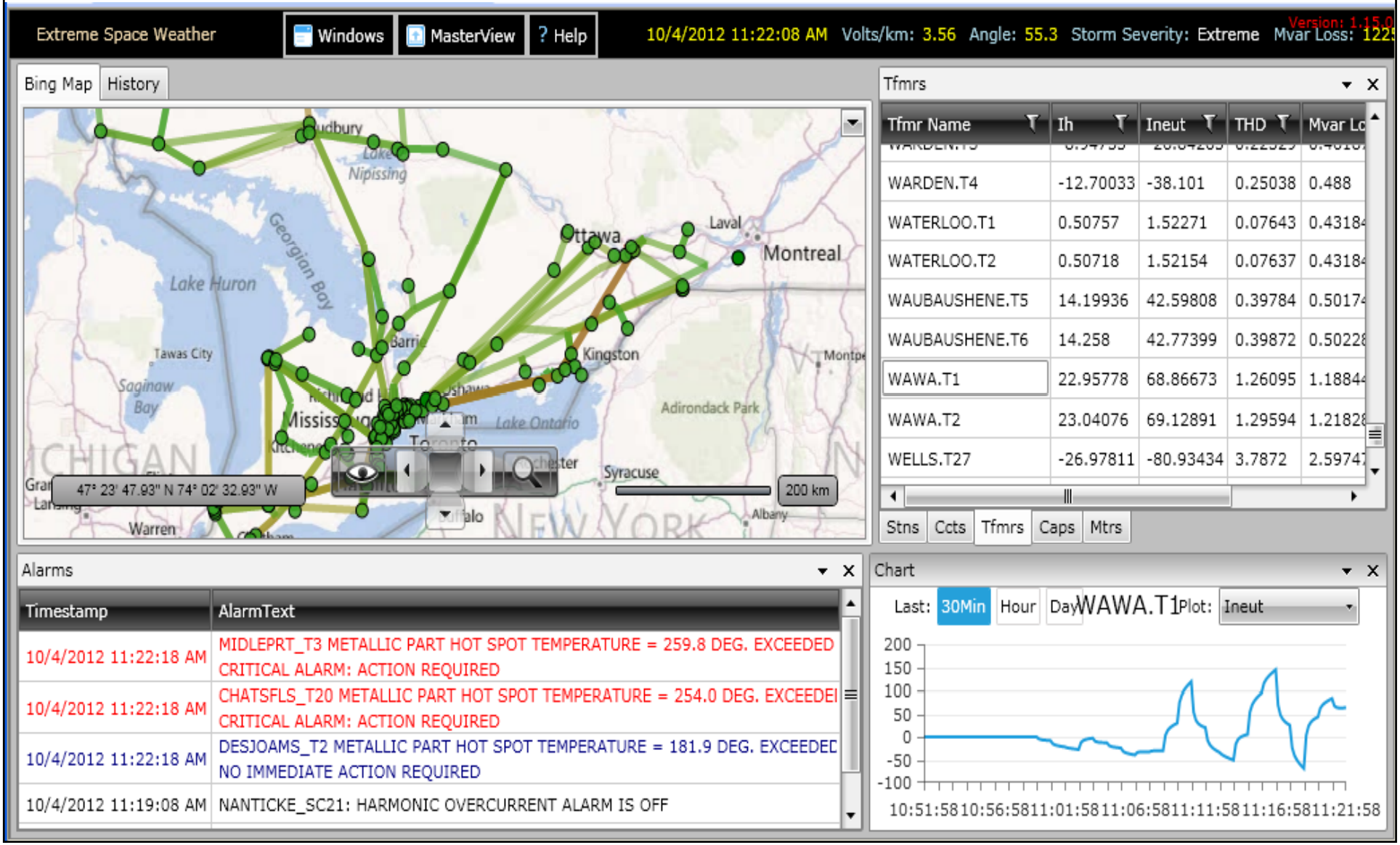
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Real time GMD management

- Magnitude and orientation of the geoelectric field
- 200 ms to 600 ms calculation cycle
- Integration with measured SCADA data
  - Voltages
  - Reactive power loss
  - DGA, top oil and winding temperature
  - Direct GIC measurements
- Situational awareness
- Alarm-based operational measures

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Real time GMD management



Planning tools

- Used for
  - Assessment of voltage collapse limits
  - Determination of vulnerable system zones
  - Transformer vulnerability assessment under any storm severity
  - Determination of reduced limits due to age or condition
  - New transformer GIC withstand specifications
  - Optimal placement of new GIC monitoring stations

Training and Awareness in Development



- Control Centre
  - Storm simulation
    - Faster than real time playback
    - Real time playback
  - Situational awareness
  - Evaluation of control actions
- System operator
  - Relationship between key var reserve limits and operating measures
  - Understanding of Storm Severity levels
  - Reliability of state estimator information (vs. telemetered) during severe GMD events)
  - Identification and recognition of storm-caused var and voltage dips

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Parting thoughts

- Geomagnetic disturbances can be a threat to the reliability of power systems if simply ignored
- Readiness for any GMD event is not an onerous burden
- It is an engineering problem
  - New off-the-shelf tools for analysis are becoming available
  - There is room for improvement in the modeling arena
  - The new spotlight on the subject will attract more researchers, and inevitably, improve tools and models
- Going forward it is only work



Discussion

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Closing Remarks

Gerry Cauley
President and CEO, NERC

RELIABILITY | ACCOUNTABILITY






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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Submit by Email

Print Form

Reliability Issues Nomination Form

RRAC RINFv1.06 11.13.2012

NERC bases its operations on four pillars: Reliability, Assurance, Learning and Risk-based Approach. In support of making risk-informed decisions and enabling prioritization of issues, please use this form to submit potential issues (with as much supporting information as you can provide) for consideration by the Reliability Issues Steering Committee (RISC). That group, supported by NERC staff, will work with the industry to help develop overall ERO strategy by identifying and prioritizing the most important reliability issues facing our industry and properly aligning resources to address them. By providing this information, you are helping to ensure the ERO is focusing on the correct priorities as it moves forward.

This form should accept basic formatting pasted from word processing applications, and the form will expand to contain any text larger than the apparent space provided.

First Name:	**Richard**	**Last Name:**	**Vine**
Your Title:	**Compliance Analyst Lead**	**Today's Date:**	**12/3/12**
Organization:	**California Independent System Operator**		
Email:	**rvine@caiso.com**	**Phone:**	**+1 (916) 608-5722**

Enter (800) 555-1212 as 8005551212

Note: In general, the RISC posts nominations for public review two weeks before each open meeting. Submitters should assume that this nomination will be posted. However, the RISC reserves the right to designate a nomination as confidential to protect critical energy infrastructure information and other information that is sensitive to one or more parties. If you believe your nomination should be considered confidential, please check the box below and provide your rationale for the RISC to consider during its initial evaluation.

☐ I believe this issue should be treated as ***confidential.***

Explanation:

Proposed Reliability Issue

Please explain the issue you are identifying.
What specific action, scenario, or behavior is creating a threat to reliability?

Version 4 of CIP Standard CIP-002, which becomes effective April 1, 2014, contains an Attachment 1 that is meant to define "bright line" criteria for determining CIP "Critical Assets". Item 1.3 in Attachment 1 states the following:

1.3. Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.

Even entities who have a very robust transmission planning process may not currently perform studies in a manner to specifically identify which "generation Facilities" are "necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon". This could result in over-designation or under-designation of those generation Facilities that should be truly classified as Critical Assets, either of which could pose a reliability concern. The reliability concern for under-designation of generation Facilities as Critical Assets is obvious. However, designation of generation units as Critical Assets that weren't previously designated as such, could also affect reliability by causing Generators to withdraw their units from the market, rather than invest in considerable upgrades to their Generation Facilities to make them "CIP-hardened".

Another concern for reliability is the possible compromise of "confidentiality" of generation Facilities designated as Critical Assets. Under present and past versions of CIP-002 entities have privately determined which of their generation Facilities were "Critical Assets". However, under Versions 4 and 5 of CIP-002, the Planning Coordinator will make this determination, most likely during annual transmission planning studies. Since these planning studies are increasingly required by tariff or other regulations to be very public and transparent, the confidentiality of those generation Facilities identified as Critical Assets may be lost.

Discussion of Possible Harm to Reliability

Please consider the following questions:

1.) ***How does the issue described directly harm reliability****? Does it directly lead to a negative outcome (e.g., a contingency or a loss of the ability to serve load)? Does it have the potential to amplify another problem or make it worse?*

2.) ***What is the scope of the issue****? Is this a North-American issue, an Interconnection-wide issue, a regional issue, or is the scope unknown?*

3.) ***Can you quantify the likely impact?*** *Do you have historical data? Can you estimate values for System Risk Index (SRI) components (generation lost, transmission circuits of various voltage classes lost, load lost for a specific duration)? Can you estimate how it might impact the Condition Driven Index (CDI) metrics*? Are there other ways to describe the possible impact?*

4.) ***How urgent of a concern is this to address?*** *Do you believe it to be an imminent threat that could strike tomorrow, or one that can wait a few months or years? How likely do you think it is that this risk will manifest (for example, a 60% chance it will occur in the next 5 years)?*

Please include or attach all information used to support your conclusions. This should include event analyses, historical data (and an explanation of its source), and any other facts or hard data that help explain the basis for considering this an issue.

This matter should be considered urgent at this point. CIP-002 v4 goes into effect April 1, 2014, and entities with generating

Facilities must be in strict compliance no longer than 6 months after that date. Therefore Planning Coordinators must quickly come up with a strategy for defining generation Facilities considered to be Critical Assets to allow adequate lead time for affected entities to plan and upgrade their Facilities as necessary. Some potentially affected Generators in the Western Interconnection started several months ago looking for guidance from their Planning Coordinators in this area.

* SRI and CDI are metrics used by NERC to evaluate overall system performance. For more information, please see the following resources. For SRI: http://www.nerc.com/docs/pc/rmwg/pas/Mar_2012_OCPC/EDI_Whitepaper.pdf and http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf ; for CDI: http://www.nerc.com/docs/pc/rmwg/pas/index_team/CDI_Whitepaper.pdf

Existing Conditions

1. *Is there anything in place that is intended to address this issue already?*
2. *Is there another group or organization currently working to develop solutions?*
3. *Does something exist that is intended to resolve this issue, but it is not 100% effective? If so, please define the gap you see and how to close it.*

FERC Order 761, which approved CIP Version 4 standards, implies that Planning Coordinators already make such determinations [regarding which generation Facilities are necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon] during performance of their normal annual planning studies under NERC Standards TPL-003 and TPL-004. In addition, the CIP-002-4 Drafting Team provided guidance on this subject in a "Rationale and Implementation Reference Document" which clarifies the following:

> "**the focus on preventing an Adverse Reliability Impact dictates that these units [generation Facilities] are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation**."

However, discussion with ISO Regional Transmission Engineering, as well as with Planning representatives from other entities, indicates that this is ambiguous. In particular, it is not clear what types of normal annual planning studies FERC believes are already being run under TPL-003 and TPL-004 to make these determinations. In addition, the Drafting Team guidance seems to exclude Facilities required for "voltage support in the local area", but does this imply that units required to prevent thermal overloads in local areas should be included?

The California ISO is working this through it's own internal Policy and Regulatory Committee and has raised these concerns at other Compliance User Group settings. However, we are not aware of any other organization who is currently working to develop solutions to this issue.

Suggested Strategy/Actions to Resolve

Please consider the following questions:

1.) ***Do you have ideas how this issue should be addressed****? What actions could be taken to address this issue (development of a whitepaper or guideline, publishing of best practices, offering training, reviewing lessons learned, development of a standard, or other approaches)?*

2.) ***Do the benefits of your suggested solution outweigh the costs?*** *Please provide any cost/benefit information you may have related to your proposed solution.*

3.) ***What does success look like?*** *What kinds of method or metrics would you use to determine if the issue has been resolved?*

We believe that a specific methodology should be developed for Planning Coordinators to better guide them in identifying

those generation Facilities in their Planning Coordinator areas which could pose "BES Adverse Reliability Impacts in the long-term planning horizon." This could be initiated at the NERC level to apply to all Regions, but perhaps would be more appropriate to be spearheaded at the Regional Entity level to more specifically address each Region's needs. This methodology should specify consideration of a minimum size of generation as well (e.g. 50 MW) to even be considered in studies meant to determine "Critical Assets". This methodology should also address how the "confidentiality" of these "Critical Asset" determinations should best be maintained.

Please click the "Submit by email" button to automatically generate an email back to NERC with your answers attached. If you have any additional supporting information to include, you will have the opportunity to attach it prior to sending the message.

Submit by Email

Print Form

Thank you for supporting the ERO!

	Board/MRC Meetings	OC	PC	CIPC	SC	CCC	RISC (proposed)
Sep 2012							26 Washington (Informal) - PAST
Oct 2012							22 Atlanta - PAST
Nov 2012							7 New Orleans - PAST
							28 RIISC Washington - PAST
Dec 2012							17 Tampa - CURRENT
Jan 2013					16-17 Atlanta		
							Jan 24th Call
Feb 2013	5-6 San Diego						**(Alternate - 2 hours after BOT)**
							Feb 12th Call
Mar 2013		5-6 Albequerque					
					7-8 Albequerque		
							March 12th Atlanta
						13-14 TBD	
Apr 2013					4 Call		
							April 16th Call
May 2013					2 Call		
	7-8 Boston						**(Alternate - 2 hours after BOT)**
							May 22nd Call
Jun 2013					5-6 Atlanta		
		11-12 TBD					
							June 18th Chicago
Jul 2013							**July 11th Call**
					18 Call		
Aug 2013							**August 8th Call**
	14-15 Montreal				15 Call		**(Alternate - 2 hours after BOT)**
Sep 2013		17-18 Denver					
					19-20 Denver		**September 26th Washington**
Oct 2013					17 Call		
							October 22nd Call
Nov 2013	6-7 Atlanta						**(Alternate - 2 hours after BOT)**
					14 Call		**TBD**

Dec 2013		10-11 Atlanta					
					12-13 Atanta		**TBD**

RISC Prioritization Exercise – Discussion Draft

MASTER DATA COMPARISON

		Avg Rank	Low Ct	Medium Ct	High Ct	HML Score	Avg Dollars
1	Cyber Attack	1.00	0	0	14	H	$18.46
2	Workforce Capability and Human Error	2.07	0	0	14	H	$12.77
3	Protection Systems	3.07	0	0	14	H	$12.00
4	Monitoring and Situational Awareness	3.86	0	0	14	H	$11.69
5	Operational Modeling and Model Inputs	6.50	0	13	1	M	$6.58
6	Equipment Maintenance and Management	7.00	1	13	0	M	$6.50
7	Coordinated Attack on Multiple Facilities	7.71	1	13	0	M	$5.04
8	Generator Availability	9.21	4	10	0	M	$3.69
9	Increased dependence on Natural Gas Generation	12.00	8	6	0	M/L?	$3.92
10	Generation Resource Adequacy	11.93	11	3	0	L	$2.03
11	Transmission Right of Way	12.07	12	2	0	L	$2.57
12	Geomagnetic Disturbance (GMD)	12.43	11	3	0	L	$2.62
13	Long Term Planning and Modeling	12.64	10	4	0	L	$2.88
14	Climate Change, Environmental Regs, Changing Resource Mix due to Environmental or Other Market Conditions, Integration of Variable Gen	12.71	11	3	0	L	$2.26
15	Integration of New Technologies	15.86	14	0	0	L	$0.96
16	Extreme Weather/Acts of Nature	16.50	12	2	0	L	$1.69
17	Demand Response	16.71	14	0	0	L	$0.92
18	Localized Physical Attack	16.79	12	2	0	L	$0.69
19	Smart Grid	17.29	14	0	0	L	$0.92
20	Electro-Magnetic Pulse (EMP)	17.50	14	0	0	L	$0.77
21	Post-Recession Demand Growth	18.21	14	0	0	L	$0.76
22	Pandemic	19.93	14	0	0	L	$0.27

Average Rank is based on the mean ranking as provided by the members of the RISC.

Low Ct, Medium Ct, and High Ct show the number of members recommending High, Medium, or Low categories. HML Score indicates the majority consensus of the members of the RISC.

Average Dollars indicates the mean allocation of dollars by the members of the RISC based on an imaginary $100 **total** available for ERO activities.

The following is a summary of the efforts of NERC's Reliability Issues Steering Committee (RISC) to develop a strategic prioritization framework for the ERO.

- NERC staff identified 41 active or planned efforts at NERC related to reliability threats, and combined them into several general categories of risk
- RISC members were asked to consider the risk impact and probability, the associated controls currently in place and their effectiveness, any gaps in control, and then ultimately provide a "post-control" priority indicating where they felt the risk should be ranked within the ERO reliability strategy.
- The RISC met in-person three times to discuss, refine, and ultimately achieve consensus on the prioritization of these issues

Additional items to be considered as next steps:

- **The RISC has not considered whether or not certain elements are within NERC's scope. Some issues may be more appropriately addressed by other organizations.**
- **The RISC did not attempt to determine the regional nature of various issues. Certain issues may be more applicable in some regions than in others.**
- **How does this prioritization integrate into NERC business planning?**
  - **For example, should the standing committees integrate these recommendations into their work plans? If so, how should that be undertaken?**
  - **How does the Standards Committee in particular align its work with these priorities and the recommendations of the RISC, given the existing Standards Processes Manual and obligations established in the Rules of Procedure?**

High Priority Issues

Description

The RISC unanimously concluded that the issues below should be the top strategic focus for the ERO.

High Priority Issues	Current NERC Efforts in this Area	Average Dollars
Cyber Attack: We have an event caused by a cyber attack on BES cyber assets.	ESISAC Implementation of DoE/DHS/WH Electricity Subsector Cybersecurity Capability Maturity Model Enforcement of CIP Standards CIP Audits CIPC Efforts	$18.46
Workforce Capability and Human Error: We have an event because someone (e.g., an operator or a field technician) makes a mistake or has an error in judgment.	Certification Training Enforcement of PER Standards Events Analysis program	$12.77
Protection Systems: We have an event become worse due to a protection system failing to operate correctly.	System Protection Coordination Standards Project Generator Relay Loadability Standards Project Protection Systems Misoperations Standards Project Protection System Misoperation Task Force System Protection and Control Subcommittee Maintenance and Testing Plans Corrective Action Plans Enforcement of PRC and TPL Standards	$12.00
Monitoring and Situational Awareness: We have an event due to a control center or similar facility either not receiving or understanding information related to system conditions.	Certification and Registration RCIS Events Analysis Program Lessons Learned NERC Alerts SAFNR II NERC Bulk Power System Awareness	$11.69
		TOTAL: $54.92

Next steps

For each of these issues:

1. Are the existing efforts sufficient, or do we need to add new efforts or make or incremental improvements to what we have?
2. Ensure that any new effort is in NERC's scope or appropriately directed to the right organization.

3. As we consider existing, new, and incremental efforts, what data is available to appropriately scope any new activity?
4. How will we measure our performance in these areas, and what defines success?
5. Should resources that are assigned to lower-priority issues be redirected toward these higher-priority issues?

Medium Priority Issues

Description

These are areas that should be researched to determine what should be focused on.

Medium Priority Issues	Current NERC Efforts in this Area	Average Dollars
Operational Modeling and Model Inputs: We have an event because our models and/or model inputs used in day-ahead and/or real-time were inaccurate or not available.	Enforcement of TPL, TOP, IRO, MOD Standards Model Validation Working Group ERAG-MMWG – Eastern interconnection Western Interconnection response to AZ/SoCal Outage	$6.58
Equipment Maintenance and Management: We have an event because we are not maintaining our equipment correctly or on schedule and something failed.	Enforcement of the FAC, PRC Standards Spare Equipment Database Task Force	$6.50
Coordinated Attack on Multiple Facilities: We have an event caused by a physical attack on infrastructure.	Enforcement of CIP, EOP Standards ESISAC CIP Audits CIPC Efforts	$5.04
Generator Availability: We have an event because generation is not available when needed (not enough generation operating).	Enforcement of BAL, TOP, IRO, MOD Standards NERC Reliability Assessments Generating Availability Data System and GADS Working Group	$3.69
Increased dependence on Natural Gas Generation: We have an event because of insufficient Natural Gas deliveries.	NERC Reliability Assessments Regional Activities	$3.92
		TOTAL: $25.73

Next steps

For each of these issues:

1. What specific areas we should be focusing on?
2. Ensure that any new effort is in NERC's scope or appropriately directed to the right organization.

3. What is the scope of this issue (e.g., should a region work on this issue, and share its results with the larger NERC community)?
4. Are the existing efforts sufficient, or do we need to add new efforts or make incremental improvements to what we have?
5. As we consider existing, new, and incremental efforts, what data is available to appropriately scope any new activity?
6. How will we measure our performance in these areas, and what defines success?
7. Should resources that are assigned to lower-priority issues be redirected toward these higher-priority issues?

Low Priority Issues

Description

Generally, these are areas that can be monitored or put on hold. For those issues where NERC currently has no active efforts, no new activities should be initiated beyond monitoring.

Low Priority Issues	Current NERC Efforts in this Area	# of Requests to be Removed	Average Dollars
Long Term Planning and Modeling: We have an event because our models and forecasts were inaccurate and did not predict the problem we experienced.	NERC Reliability Assessments System Analysis and Modeling Subcommittee Performance Analysis Subcommittee System Protection and Control Subcommittee	0	$2.88
Geomagnetic Disturbance (GMD): We have an event because of a Geomagnetic Disturbance.	NERC Reliability Assessments GMD Task Force	1	$2.62
Transmission Right of Way: We have an event due to a forced outage of part of the transmission system caused by a right-of-way incursion.	Enforcement of FAC Standards NERC Reliability Assessments Transmission Availability Data System and TADS Working Group	1	$2.57
7a Climate Change, Environmental Regulations, Changing Resource Mix due to Environmental or Other Market Conditions, Integration of Variable Generation	NERC Reliability Assessments Integration of Variable Generation Task Force	0	$2.26
Generation Resource Adequacy: We have an event due to a lack of Resource Adequacy (not enough generation built).	NERC Reliability Assessments Electricity Supply and Demand	1	$2.03
Extreme Weather/Acts of Nature: We have an event caused by a hurricane, flood, earthquake, etc…	NERC Reliability Assessments	5	$1.69

Integration of New Technologies	NERC Reliability Assessments Smart Grid Task Force	2	$0.96
Demand Response	Demand-Response Availability Data System and DADS Working Group NERC Reliability Assessments	4	$0.92
Smart Grid	Smart Grid Task Force Planning Committee activities CIP	4	$0.92
Electro-Magnetic Pulse (EMP): We have an event due to an electro-magnetic pulse attack	None	4	$0.77
Post-Recession Demand Growth	NERC Reliability Assessments	4	$0.76
Localized Physical Attack	Enforcement of CIP, EOP Standards ESISAC CIP Audits CIPC Efforts	7	$0.69
Pandemic: We have an event due to loss of key personnel due to pandemic	HILF Task Force Electricity Sub-Sector Coordinating Council	6	$0.27
			TOTAL: $19.34

Next steps

For each of these issues:

Other than watching for related Reliability Issue Nominations, how will we monitor these issues to determine if their priority changes?

Discretionary Activities

Inevitably, there may be issues NERC needs to address outside the prioritization process. Practical improvements, interpretations, responses to regulatory directives, and similar activities may not be accounted for directly in the priorities established above, but may nonetheless be required to be undertaken and completed. Some examples could include:

- Paragraph 81 efforts to streamline and optimize the standards
- Efforts to modify the Standards Processes Manual or Rules of Procedure
- Work associated with any potential directives related to Geomagnetic Disturbances

It would be easy to simply allocate 100% of our resources to the reliability priorities described above. However, to account for these "other" activities, we may want to think about maintaining some amount of resources available for discretionary use.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Submit by Email

Print Form

Reliability Issues Nomination Form

RRAC RINFv1.06 11.13.2012

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This form should accept basic formatting pasted from word processing applications, and the form will expand to contain any text larger than the apparent space provided.

First Name:	David	**Last Name:**	Dworzak
Your Title:	Director, Reliability Policy	**Today's Date:**	12/3/12
Organization:	Edison Electric Institute		
Email:	ddworzak@eei.org	**Phone:**	+1 (202) 508-5684

Enter (800) 555-1212 as 8005551212

Note: In general, the RISC posts nominations for public review two weeks before each open meeting. Submitters should assume that this nomination will be posted. However, the RISC reserves the right to designate a nomination as confidential to protect critical energy infrastructure information and other information that is sensitive to one or more parties. If you believe your nomination should be considered confidential, please check the box below and provide your rationale for the RISC to consider during its initial evaluation.

☐ I believe this issue should be treated as ***confidential.***

Explanation:

Proposed Reliability Issue

Please explain the issue you are identifying.
What specific action, scenario, or behavior is creating a threat to reliability?

What specific action, scenario, or behavior is creating a threat to reliability?

Previous events have demonstrated that Geomagnetic Disturbance (GMD) events could have an adverse, wide-area impact on the reliable operation of the Bulk Electric System (BES). A severe GMD event can produce geomagnetically induced currents (GIC) sufficient to drive transformer cores into half-cycle saturation. The results of half-cycle saturation can cause increased hotspot heating from stray flux that could result in transformer damage, and increased var losses that can depress system voltages beyond recovery. In addition, half-cycle saturation of transformer cores also causes harmonic distortion that can cause certain protective relays to misoperate resulting in loss of reactive power support (*e.g.,* capacitor banks, SVCs), line outages, etc. at a time when reactive power is most needed.

Discussion of Possible Harm to Reliability

Please consider the following questions:

1.) ***How does the issue described directly harm reliability****? Does it directly lead to a negative outcome (e.g., a contingency or a loss of the ability to serve load)? Does it have the potential to amplify another problem or make it worse?*

2.) ***What is the scope of the issue****? Is this a North-American issue, an Interconnection-wide issue, a regional issue, or is the scope unknown?*

3.) ***Can you quantify the likely impact?*** *Do you have historical data? Can you estimate values for System Risk Index (SRI) components (generation lost, transmission circuits of various voltage classes lost, load lost for a specific duration)? Can you estimate how it might impact the Condition Driven Index (CDI) metrics*? Are there other ways to describe the possible impact?*

4.) ***How urgent of a concern is this to address?*** *Do you believe it to be an imminent threat that could strike tomorrow, or one that can wait a few months or years? How likely do you think it is that this risk will manifest (for example, a 60% chance it will occur in the next 5 years)?*

Please include or attach all information used to support your conclusions. This should include event analyses, historical data (and an explanation of its source), and any other facts or hard data that help explain the basis for considering this an issue.

How does the issue described directly harm reliability?

Based on the findings of the NERC *March 13, 1989 Geomagnetic Disturbance Report*, and the *NERC 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System* there are two risks that result from the introduction of GICs into the bulk power system:

1. Damage to bulk power system assets, typically associated with transformers, and
2. Loss of reactive power support, which could lead to voltage instability and power system collapse.

What is the scope of the issue?

The evidence gathered from the 1989 event indicates that, even during an exceptionally intense magnetic storm, certain regions of the country experience different impacts of GIC severity based on latitude. Although induced currents vary, if one region experiences voltage instability and/or collapse then a larger area up to an entire interconnection could be affected.

Can you quantify the likely impact?

Restoration time will be different for each of the aforementioned risks. A loss of reactive power support resulting in voltage instability will typically have a restoration period of hours or days at most. In contrast, damage to equipment will create the necessity of replacement, and will vary by the availability of spares and severity of the number of assets damaged.
If transmission owners/ operators and generation owners/operators fail to prepare for a GMD event after being notified of impending solar activity it is conceivable that instability, uncontrolled separation or cascading outages of the BES could occur.

How urgent of a concern is this to address?

We are presently approaching the peak of Solar Cycle 24, an eleven year solar cycle. Severe GMDs typically occur one to two years before and after the anticipated peak. The peak for this cycle is anticipated to occur in the 2013-2014 time period.

Attachment links:

i. *NERC March 13, 1989 Geomagnetic Disturbance Report*
(http://www.nerc.com/files/1989-Quebec-Disturbance.pdf)

ii. *NERC 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*
(http://www.nerc.com/files/2012GMD.pdf)

iii. *NRC Information Notice No. 90-42 "Failure of Electrical Power Equipment Due To Solar Magnetic Disturbances", June 19, 1990.*
(http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/1990/in90042.html)

* SRI and CDI are metrics used by NERC to evaluate overall system performance. For more information, please see the following resources. For SRI: http://www.nerc.com/docs/pc/rmwg/pas/Mar_2012_OCPC/EDI_Whitepaper.pdf and http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf ; for CDI: http://www.nerc.com/docs/pc/rmwg/pas/index_team/CDI_Whitepaper.pdf

Existing Conditions

1. *Is there anything in place that is intended to address this issue already?*
2. *Is there another group or organization currently working to develop solutions?*
3. *Does something exist that is intended to resolve this issue, but it is not 100% effective? If so, please define the gap you see and how to close it.*

Is there anything in place that is intended to address this issue already?

The *NERC 2012 Special Reliability Assessment Interim Report* contains guidance for transmission owners/ operators and generator owners/operators to utilize in order to prepare for possible solar activity. Many operators, especially those in the northern latitudes, have instituted operating procedures in order to prepare for an event.

Reliability Standard requirement IRO-005, 3a requires Reliability Coordinators to notify Transmission Operators and Balancing Authorities of an impending GMD event with a K-index of 7 or greater when notified via the Reliability Coordinator Information System (RCIS) or the NERC Hotline.

Is there another group or organization currently working to develop solutions?

NERC has identified two key focus areas based on the conclusions of the 2012 interim report. NERC is proposing to work with governmental agencies and private sector efforts to focus on: 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 operating practices to respond to GMD and updating the NERC Industry Alert. These key areas are to be addressed by the GMDTF and will focus on resolution of four recommendations identified in the interim report:

- Recommendation 1: Improvement of tools for industry planners to develop GMD mitigation strategies
- Recommendation 2: Improvement of tools for system operators to manage GMD impacts
- Recommendation 3: Education and information exchanges between researchers and industry
- Recommendation 4: Review the need to enhance NERC Reliability Standards

A more detailed outline of these activities is included in the link to the *Scope and Project Plan for the GMDTF Phase 2*
(http://www.nerc.com/docs/pc/gmdtf/GMD_Phase_2_Project_Plan_APPROVED.pdf)

On October 18, 2012, the FERC issued a Notice of Proposed Rulemaking to address Reliability Standards for Geomagnetic Disturbances. The NOPR proposes to create two separate standards to address specific issues as outlined by the Commission. More detail on the NOPR may be obtained at the following link to the FERC library:
i. *Notice of Proposed Rulemaking re Reliability Standards for Geomagnetic Disturbances under RM12-22.* (http://elibrary.ferc.gov:0/idmws/file_list.asp?document_id=14060447)

Does something exist that is intended to resolve this issue, but it is not 100% effective?

We are not aware of any other continent-wide initiatives to resolve these issues.

Suggested Strategy/Actions to Resolve

Please consider the following questions:

1.) ***Do you have ideas how this issue should be addressed****? What actions could be taken to address this issue (development of a whitepaper or guideline, publishing of best practices, offering training, reviewing lessons learned, development of a standard, or other approaches)?*

2.) ***Do the benefits of your suggested solution outweigh the costs?*** *Please provide any cost/benefit information you may have related to your proposed solution.*

3.) ***What does success look like?*** *What kinds of method or metrics would you use to determine if the issue has been resolved?*

Do you have ideas how this issue should be addressed?

There are several different concurrent activities intended to most appropriately determine a way to address the issues as outlined in the reports and as defined by ongoing activities. Here are the areas that should be addressed:

- The GMDTF should review the completion dates for its deliverables in order to determine if it is possible to expedite the availability of models and tools necessary to accurately assess the impact of a GMD event and determine what mitigation measures may be applied.
- RISC should determine if a standard is needed to address a possible reliability gap in order to assure that Transmission Owners/Operators and Generation Owners/Operators have operating procedures in place in order to prepare for a possible GMD event.
- RISC should evaluate the activities of the GMDTF to determine if a standard is needed to require system modeling and determination of mitigation measures in order to create a useful and meaningful standard to insure that operating procedures and mitigation measures that are utilized maintain the reliability of the BES.
- The Standards Committee should address the creation of a Standard Drafting Team if the industry and/or NERC determine that a SAR is necessary to create a standard to address operating procedures. The Standard Committee should also consider is a SDT is needed to address system evaluation and mitigation as determined by the RISC.
- The NERC BOT should work with FERC Commissioners to educate them on the ongoing efforts at NERC and the industry and establish a spirit of cooperation to create requirements that focus on reliability of the BES.

Do the benefits of your suggested solution outweigh the costs?

It is difficult to accurately determine the financial impact of a high impact low frequency event (HILF). Specifically, at this point in time, without accurate modeling tools to determine the impact that a severe GMD might have on BES equipment or what might be needed to most effectively mitigate the impact on equipment or to determine what modifications must be made to the protective system to insure that harmonics do not inappropriately trip reactive support devices, the costs of mitigation are purely speculative. In addition, estimates of outage and societal costs to use as a comparison are speculative unless modeling can more appropriately determine a more realistic impact to BES equipment as well as voltage instability.

What does success look like?

If an exceptionally intense geomagnetic storm occurs and the industry 1) executes a clear, concise, and timely notification procedure to all reliability entities, and 2) said entities implement and exercise effective operating procedures and communications protocols that employ adequate mitigation measures to insure reliable operation of the BES. There should also be a goal for the industry to determine the possible impact of such events as accurately as possible and develop mitigation measures that are adequate yet cost effective.

Please click the "Submit by email" button to automatically generate an email back to NERC with your answers attached. If you have any additional supporting information to include, you will have the opportunity to attach it prior to sending the message.

Submit by Email

Print Form

Thank you for supporting the ERO!

RISC Meeting, FRCC Tampa, December 17th 12-5 pm.

In Person Meetings will be more limited. An Excel spreadsheet was presented showing call in meetings replacing some of the in person meetings. January will be a webinar call, February will be a meeting after the BOT.

Risk Prioritization Exercise- 41 reliability initiatives in 12 categories. Prioritization- High Risk Bucket has 4 categories however from the discussions although these are vitally important categories there doesn't seem to be significant "outstanding" risk for any of these…,

Cyber Attack-Other activities already underway
Workforce Capability and Human Error-problem is largely undefined
Protection Systems-doesn't seem to be any outstanding risk issue here
Monitoring and Situational Awareness-perhaps some real time tools work.

The various risks in the categories may not necessarily be within NERC's scope and the chair mentioned that this would need further discussion. The next steps will be up to NERC and/or the appropriate committee to act on the risk. In general, High categories are definitely for ERO action. Mediums may cut across the ERO and regional category. The Committee is not very supportive of doing much with the Low category and it may add value but not at the expense of taking action on Medium Risks.

At the January meeting one of the High Risk Categories will be discussed in detail. Allen is concerned that the CIP standards are in process and unsettled. Gerry noted that the category needs to be more granular to allow anything to move forward. Mention made of needing a better rendition of what the actual problem is and what could be done to address it. Gerry also wants to identify any gaps that might exist between what is planned for the BP and Budget and what is being identified by this group. Chair mentioned that the middle column containing the problem statement is too high level and needs more detail. Chair and Janice Case wants NERC to add detail. Much discussion about parsing out resources based on a "100 dollar proxy" and allocating on a per risk basis where NERC should spend its money. Seems out of scope for this group and a lot of time devoted to "allocating" the 100 dollars.

Gerry provided a summary and the top four risks-Cyber Security is top. Intelligence that is being received indicates that the threats are increasing. CIP V5 approved by stakeholders and BOT and will be filed soon with a transition over the next two years. Information sharing is a multiple part effort, ESIAC is a coordinated effort with 15 different intelligent agencies and the info. Is put into non-confidential information to be shared. ERO is interested in ready to go briefing centers. Workshops and training, GridEx will be done every two years (cyber security exercise). Maturity model-a 10 factor assessment of your security program and the entity gets a grade-(6-8 will be done a year). One gap that may exist is the "supply chain gap" where increasing amounts of technology are coming from overseas with potential vulnerabilities built in. Chair is worried about potential duplication of effort in the area of Cyber security. RISC concerned about the maturity model. Seems like this should not be done by the ERO and a number of the committee believes that this is more of a transmission forum activity. The maturity model is something that someone can be trained to do. Gerry mentioned it could be regional or some other third party.

Human Error is believed to be very contributory to a number of events that have come about. There is consultant who will be helping in the event analysis area and a two workshops doing outreach. No particular intervention is planned. There is a lot of complexity built into the controls and microprocessors that is coming into play with some errors. Problem is still being defined and Gerry doesn't believe that something will be available by February 2013.

Protection systems driven by the existing standards-relay maintenance, relay misoperations with a consolidated database and trending. Relay loadability is another standard that is risk intervention that has mitigated risk.

Situational awareness- Gerry believes there are fairly good standards in place. Work is going on now within WECC and surveys have been done in other regions to determine that level of situational awareness exists that needs to be there. There is some work that may be undertaken in "real time tools" that may mitigate some risk but there is no active risk that is undeveloped.

In general, there is a lack of data that the RISC has to do further work at this time. Gerry will provide more data.

In the Medium and Medium Low priority category, 5 categories exist;

Operational Modeling and Model Inputs
Equipment Maintenance and Management
Coordinated Attack on Multiple Facilities
Generator Availability
Increased dependence on Natural Gas Generation

In the low category there are 13 categories :

Generation Resource Adequacy
Transmission Right of Way
Geomagnetic Disturbance (GMD)
Long Term Planning and Modeling
Climate Change, Environmental Regs, Changing Resource Mix due to Environmental or Other Market Conditions, Integration of Variable Gen
Integration of New Technologies
Extreme Weather/Acts of Nature
Demand Response
Localized Physical Attack
Smart Grid
Electro-Magnetic Pulse (EMP)

Post-Recession Demand Growth
Pandemic

Risk Nomination Forms have no prescreen. Any and all forms go to the entire RISC if received 2 weeks or more before the meeting.

GMD NOPR out and comments due on December 24th. Chair thinks something should be recommended to the BOT for GMD. Most seemed to think that there is insufficient engineering background to develop standard. The ERO will be faced with developing a standard. The RISC generally agrees that a standard will not be effective because of improper scope and technical background. The RISC is advocating that the GMD TF work be completed and then and only then should this group be advocating technical standards. Gerry is very concerned that the technical engineering won't be done in time to develop an effective solution and wants the RISC to develop an urgency statement to get the technical work done at the committee level. RISC charged NERC Staff to look at the data that has been collected and also to instruct the GMD TF to strive to finish their work in the technical area and reveal their timelines and deliverables to coordinate this with the NOPR and ruling and in January. Also in the near term to have the regions report out their GMD practices. This would be used to develop a guideline/best practice document in advance of the completion of the GMD work. NERC will draft a letter to the PC/OC/SC to notify them of what RISC wants.

Discussion of how a PC identifies critical assets and a nomination form was submitted. Concern over lack of uniformity and notifications and confidentiality. Concern mainly over generators being identified as critical. This is an issue for WECC and not one for the EI or ERCOT. Allen Mosher does not see the risk to reliability here. Either the CAISO or some other PC identifies the generator as critical or not. The RISC is the inappropriate place to talk about interpretations and this needs to go to the SC or the PC and OC. This is not a significant risk that requires policy guidance for the BOT. This should go to the SC as an interpretation. RISC wants to go back to the nomination form submitter and ask them to resubmit it as an interpretation. This is another example of why the Single Portal Process is needed.

For January 24 meeting, Draft on Prioritization, Draft of Presentation to BOT, more complete tables on the risks.

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Agenda
Reliability Issues Steering Committee

December 17, 2012 | 12:00-5:00 p.m. EST

Florida Reliability Coordinating Council Offices
1408 N Westshore Blvd Suite 1002
Tampa, FL 33607
(813) 289-5644

Dial-In: (866) 740-1260 PassCode: 5247070 Security Code: 120719

Welcome, Introductions, Chair's Remarks, and Meeting Schedule (0.5 hours)

NERC Antitrust Compliance Guidelines and Public Announcements

Agenda

1. **Unfinished Items**
   a. Prioritize all strategic risk categories (1.5 hours)
2. **New Items**
   a. **Integrating with NERC Planning (1.5 hours)**
   b. **Nominations (1.5 hours)**
      RISC discussion of issue nominations received prior to December 3.[1]
3. **Action Item Review**
4. **Adjourn**

[1] Any nomination received after this date will be reviewed at a future meeting of the RISC

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GMD Task Force

Project Update

Ken Donohoo, Chairman, GMDTF

Reliability Issues Steering Committee

January 24, 2013

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Project Scope

- Supports the key areas identified in 2012 Special Reliability Assessment
  - Assessing vulnerability of transformer fleet
  - Disseminating best practices in operations
- Provide industry expertise and forum for peer review
- Collaboration with Electric Power Research Institute, government, and private sector research
- Solid technical basis for determining risks and deploying mitigating solutions

Project Tasks

- Project plan tasks in line with the recommendations from the 2012 GMD Special Reliability Assessment
  - **Recommendation 1:** *Improvement of tools for industry planners to develop GMD mitigation strategies*
  - **Recommendation 2:** *Improvement of tools for system operators to manage GMD impacts*
  - **Recommendation 3:** *Education and information exchanges between researchers and industry*
  - **Recommendation 4:** *Review the need to enhance NERC Reliability Standards*

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Progress (1)

- **Recommendation 1:** *Improvement of tools for industry planners to develop GMD mitigation strategies*
  - Finalized ground conductivity models; GIC calculation guidelines in development to complete Q3 2013
  - On target to complete extreme GMD scenarios in Q3 2013
  - Working with EPRI to facilitate transformer modeling and testing and examine GIC mitigation systems

Progress (2)

- **Recommendation 2:** *Improvement of tools for system operators to manage GMD impacts*
  - GMD operating procedures template developed from NERC Alert (May 2011) and current industry best practices.
  - Technical review and industry comment February-March 2013

NOPR RM 12-22

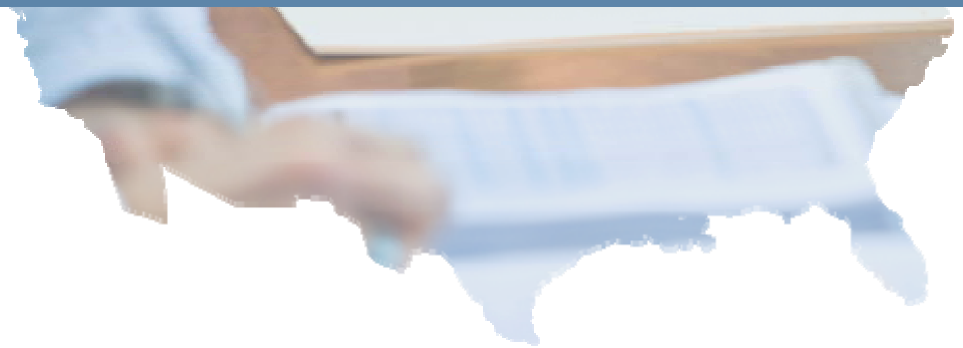
- Proposes to direct NERC to develop standards
  - Stage 1: Operation Procedure standard(s) within 90 days of final rule
  - Stage 2: Planning/assessment standard(s) within 6 months of final rule
- Proposes to direct NERC to identify "appropriate blocking measures"
- Highlights of NOPR comments
  - Industry support to manage GMD risks
  - Technical development needed for planning/assessments
  - Support for GMD Task Force

Project Task Schedule

Task	Project Completion Date
GMD Operating Procedures best practices survey and template	March 2013
Develop 1-D conductivity model of North America	Complete
Application guide for calculating GIC in power system	September 2013
Reference storm and maximum theoretical field calculations	September 2013
Thermal/ magnetic model validation of initial transformer population	January 2014
Evaluation of mitigation operating procedures and existing technologies	January 2014



Questions and Answers



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Back-up Slides

Progress on Phase 2 Plan (3)

- **Recommendation 3:** *Education and information exchanges between researchers and industry*
  - Ongoing work with IEEE Transformers Committee
  - GMD was focus of the IEEE Power and Energy Society 2012 General Meeting (Vancouver, BC)
  - Working with EPRI to develop a virtual Center of Excellence for sharing GMD information

Progress on Phase 2 Plan (4)

- **Recommendation 4:** *Review the need to enhance NERC Reliability Standards*
  - Originally intended to follow other work
  - FERC issued GMD NOPR, standard development will proceed as directed in the final rule
  - Implementation plan will take other Task Force developments under consideration

Request for Phase 2 GMD Task Force Subgroup on Financial Aspects of GMD

Thomas S. Popik

Chairman, Foundation for Resilient Societies

Financial Aspects of Geomagnetic Disturbance

- **Unmitigated Costs of Geomagnetic Disturbance (GMD)**
  - **Premature Transformer Failures Due to Overheating and Vibration, Including Lost Generation Revenue and Increased Insurance Premiums**
  - **Grid Blackouts and Load Shedding Due to Reactive Power Consumption with Voltage Collapse and/or Premature Equipment Failure, Including Regulatory Penalties and Civil Liability**
  - **Directionally Indicative Data But With Statistically Small Sample Size: Lower Capacity Utilization for Nuclear Power Plants During High Geomagnetically-Induced Current (GIC) Years of Solar Cycle and Lower Net Operating Income of Investor-Owned Electric Utilities**
- **Costs of GMD Mitigation Using "Operating Procedures" Only**
  - **Nuclear Regulatory Commission Power Reactor Status Reports: Downrating of Vulnerable GSU Transformers and Lost Generation Revenue**
  - **Published Work by Forbes and St. Cyr: Transmission Line Congestion and Off-Cost Dispatch**
  - **Probability-Adjusted Cost of Network Collapse and/or Equipment Failure During Severe Solar Storms**
- **Costs of GMD Mitigation Using Hardware-Based Schemes**
  - **Network Modeling of GMD Effects**
  - **Neutral Current Blocking Devices**
  - **Series Capacitors**

Previous Proposals for Phase 1 GMD Task Force Examination of Financial Aspects of GMD

- **Emprimus October 8, 2011 Email to GMD Task Force from G. Nordling**

  "…there are two topics which I believe need separate chapters addressing...The economic penalty or costs incurred by and will likely be incurred by utilities because of rearranging/rescheduling higher cost generation to preserve grid stability in response to a severe solar storm warning. We have taken the liberty to attach a very preliminary rough draft of a proposed article analyzing this and even how utilities can earn a profit installing an appropriate blocking device (now that there are 3 potential blocking alternatives)."

- **Foundation for Resilient Societies January 19, 2012 Comment to GMD Task Force from T. Popik**

  "The draft report does not contain any cost-benefit analysis of GIC mitigation alternatives despite suggestions by GMD Task Force participants. In 2010 the Oak Ridge National Laboratory released the report 'Electromagnetic Pulse: Effects on the U.S. Power Grid.' The Oak Ridge report concluded, 'Naturally occurring EMPs are produced as part of the normal cyclical activity of the sun...the average yearly cost of installing equipment to mitigate an EMP event is estimated at less than 20 cents per year for the average residential customer…'"

- **Financial Aspects of GMD Not Investigated in Phase 1 of GMD Task Force and Not Addressed in GMD Task Force Interim Report**

Request for Phase 2 GMD Task Force Subgroup on Financial Aspects of GMD

- **None of the Four Current GMD Task Force Subgroups Are Addressing Financial Aspects of GMD**
- **To Support Cost-Recovery Rules, It Is Insufficient to Depend Entirely on Individual Utility Analyses of Costs and Benefits of GMD Mitigation**
  - **"Evaluate the value of the approaches – calculating costs and the associated reduction in risk for each risk or combination of risks." (Ch. 12.2 of Interim Report on GMD)**
- **Not Analyzing Financial Aspects of GMD Mitigation Could Lead to Erroneous Conclusions and Delay Beneficial Recommendations**
  - **Some Mitigation Equipment Can Preclude GIC Entry into EHV Transmission Systems, Resulting in Less in Off-Cost Dispatch, Reduced Reactive Power Consumption, and Longer Transformer Life**
  - **Other Mitigation Steps May Increase "GIC Withstand" But Not Reduce Off-Cost Dispatch If GICs Enter EHV Transmission Systems—Example: Power Transformers with Specified GIC Withstand**
  - **Some Mitigation Equipment May Be Eligible for Cost-Recovery Under Existing FERC Authority; Other Equipment May Be Ineligible; Consequences for Investment Payback**
- **Our Request: Create 5th GMD Task Force Subgroup on Financial Aspects of GMD**

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Electricity Subsector 101

Enhancing Reliability, Security and Leveraging Partnerships

Tim Roxey - NERC
Chief Cyber Security Officer
Director –ES-ISAC

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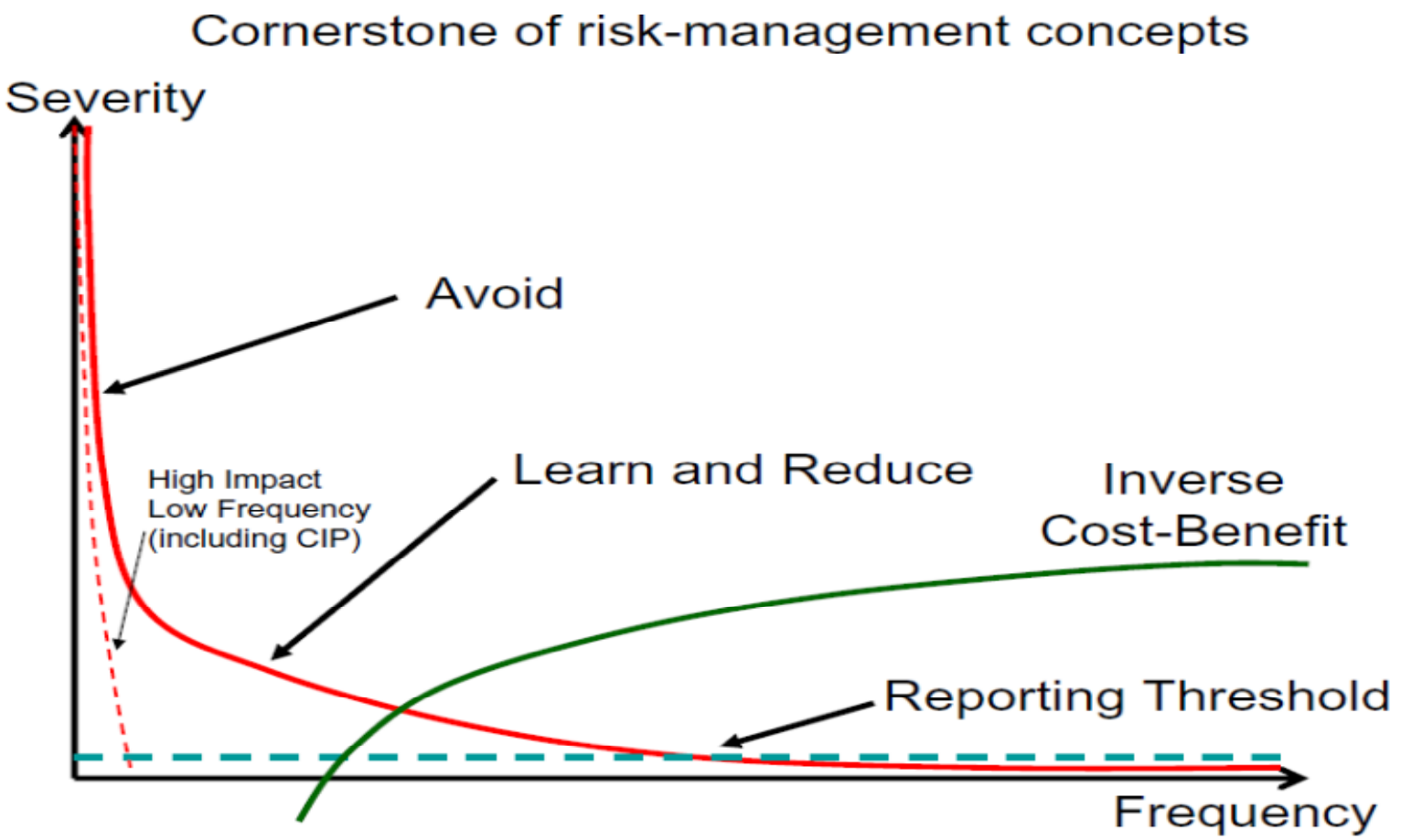



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Agenda

- Reliability Risk Management Concepts
- Put Cybersecurity into Perspective
- Articulate the Vision from Strategic to Tactical
- Implement Strategy with Partnerships
  - ESCC, ES-ISAC, CSCSWG, ICSJWG
- Opportunities

Reliability Risk Management Concepts



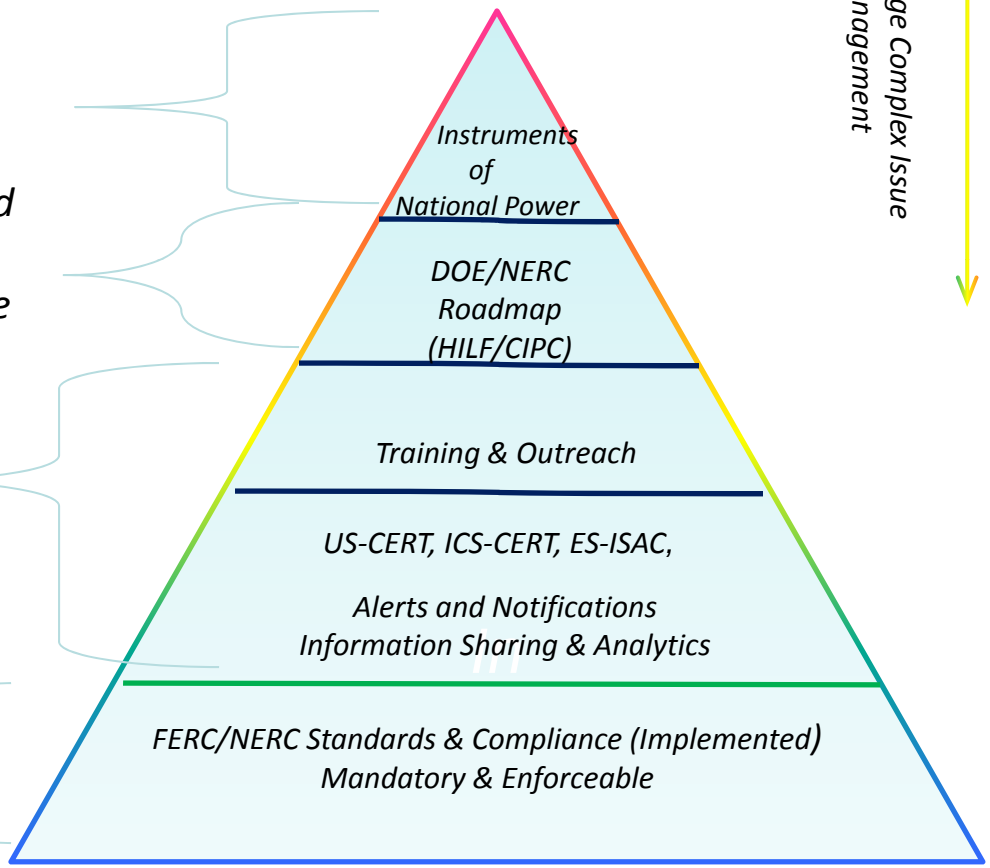
Cybersecurity Elements

National Policies

Threats, Vulnerabilities and Consequences requiring coordinated Public/Private Response

Newly Discovered Vulnerabilities and Consequences

Vulnerability Consequences



Large Complex Issue Management

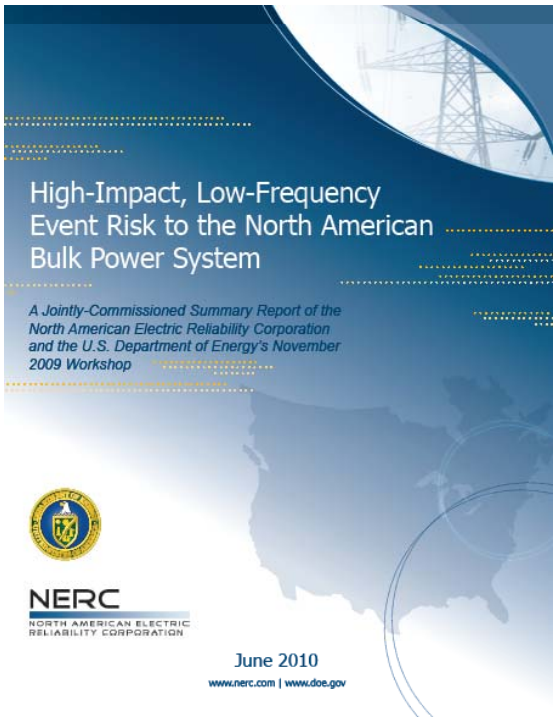
Manage Security

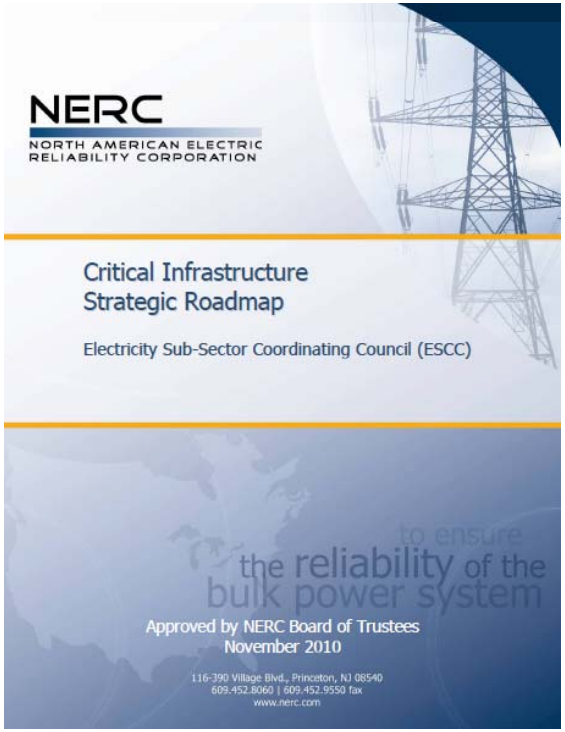
Manage Compliance

Articulate the Vision Strategic to Tactical

Strategic direction, coordinated action

Vision → Goals → Risk Priorities → Scenario-based Approach → Coordinated Action Plan

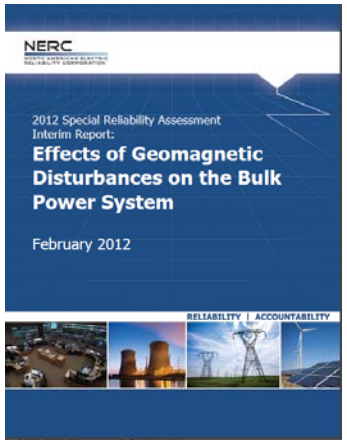




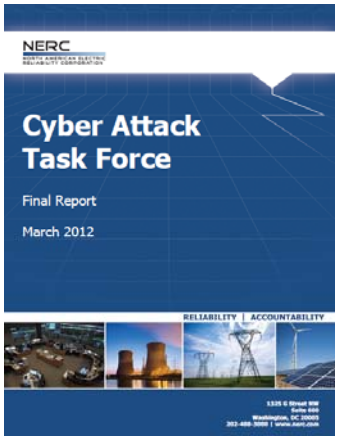


Geomagnetic Disturbances and Cyber Attack

- Report approved by NERC Board of Trustees and publicly released on February 29, 2012
  - Evaluates GMD effects on equipment and the bulk power system
  - Identifies the most likely failure mode and possible impact

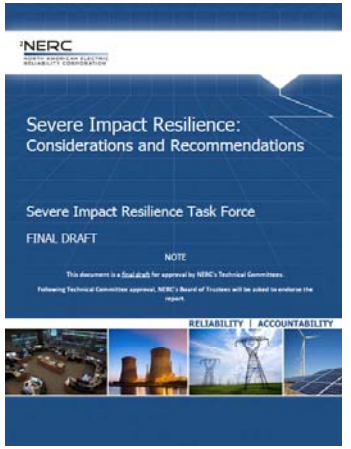


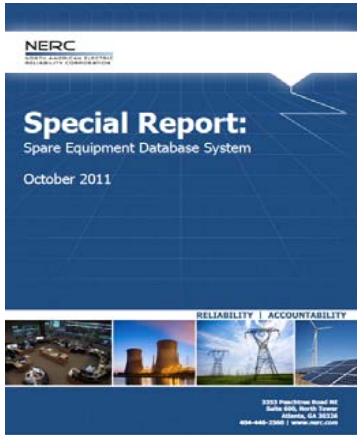
- Report accepted by NERC Board of Trustees and publicly released May 2012
  - Profile of a coordinated cyber attack
  - Detect, deter, defend, and respond practices



Severe Impact Resilience and Spare Equipment Database

- Report accepted by NERC Board of Trustees and publicly released May 2012
  - Provides recommendations to enhance grid resilience in the face of a coordinated physical attack, coordinated cyber attack, or geomagnetic disturbance
- Report accepted by NERC Board of Trustees and publicly released November 2011
  - Developed a consistent and confidential method for tracking the availability of long lead-time high voltage transformers





Implement Strategy with Partnerships

- National Infrastructure Protection Plan (NIPP) Framework
  - CIPAC with a FACA waiver – Protected collaborations
- Government and Private Sector Coordination
  - Electric Sector Coordinating Council (ESCC)
    - NERC is Chair and Secretary
  - Government Sector Coordination Council
    - DoE is Sector Specific Agency (SSA)
- Information Sharing and Analysis Centers
  - NERC hosts the ES-ISAC
  - Communications, Information Technology, Water, Dam, Emergency Services, Transportation, and others

Threat Intelligence to Action

- ES-ISAC threat stream
  - BPS Entity reporting of Indicators and Warnings
  - US - DHS (NCCIC, US & ICS CERT, HITRAC), DoE (OER, IN), DoD, NSA, FBI, and others
  - Canada – Public Safety Canada, CSIS, CCERT
  - Other – The friendly Five Is
- ES-ISAC vulnerability stream
  - National Labs – PNNL, INL, Argonne, and others as needed
  - Independent - Various consultancies' and independent researchers.
  - The CSCSWG and ICSJWG

Threat Intelligence to Action

- Collaborations
  - Collaboration with government and industry (Department of Homeland Security, Department of Energy, and HYDRA)
- Enhanced analytical capabilities
  - Attack Tree Threat Modeling
  - BPS Grid Mapping
  - Baseline Patterns and Analysis
  - Integration Support Services for Wall of Knowledge

Threat Intelligence to Action

- Alerts
  - Level 1, Industry Advisory: informational
  - Level 2, Recommendation to Industry: recommend specific action
  - Level 3, Essential Actions: actions deemed to be “essential” to BPS reliability
- ES-ISAC Portal
  - Threat environment information
  - Voluntary sharing of threat or vulnerability information
  - News feed, discussion forums, collaboration zones
- Training and education
  - Issue specific webinars
  - Monthly ES-ISAC calls
  - Cyber risk preparedness assessments (CRPA)
  - Cybersecurity Capability Maturity Model (C2M2)

Metrics – Are we any better?

Cybersecurity measures is very complex. Program measures abound, underlying security effectiveness is elusive

Several efforts are underway to develop Metrics

- The CIPC
  - Sponsor of the Bulk Electric Systems Security Metrics Working Group
  - Charged with providing a set of metrics to measure the performance of the controls that safeguard the reliability, and resiliency of the BES
- The ICSJWG Established the Joint Working Group (CIPAC/FACA)
  - Charged with developing methods and measures to assess the effectiveness of ICS across all CIKR
- Work is in progress now!



Question & Answer

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Event Analysis and Trends

James Merlo, Associate Director of Human Performance

Reliability Issues Steering Committee

January 24, 2013

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Topics

- Events Analysis (EA) Process
- Update on Reported Events to Date
- Cause Coding Process
- Initial Trends and Clusters
- Preliminary Analysis of Energy Management System (EMS) failures
- Questions

Event Analysis Program

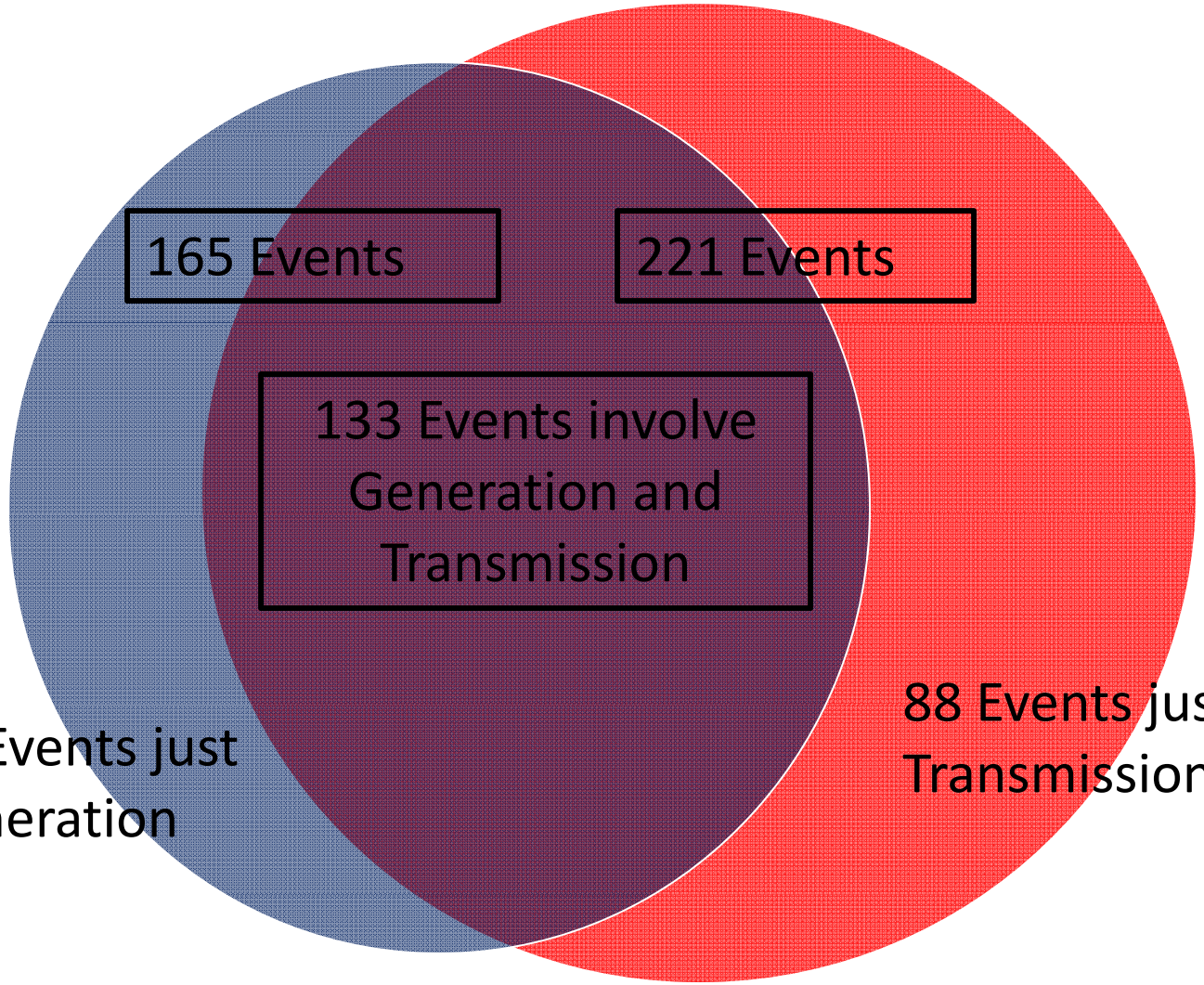
- Events in 2012
  - (Cat 1- Cat 5) Events = 111
    - Cat 1 = 73 events
    - Cat 2 = 33 events
    - Cat 3 = 3 events
    - Cat 4 and 5 = 1 each
- Total Events (October 2010 – December 2012)
  - (Cat 1- Cat 5) Events = 255
    - Events closed = 236 (92.5 percent)
    - Closed events Cause Coded = 202 (85.6 percent)
- 2013 cause coding collaboratively with Regions
    - EA report quality improving
    - Providing analysis to NERC Committees

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Event Characteristics

- There are 80 different Characteristics of Events that NERC tracks in 9 Major Categories:
  - Natural Events (lightning, hurricanes, etc.)
  - Entity Operations (Switching, Maintenance, etc.)
  - Controls/Communication (EMS, SCADA, ICCP Data, etc.)
  - Industry Alerts (pubic appeals, EEA, etc.)
  - System Tools (Load Management Tools, etc.)
  - Infrastructure Security (Vandalism, Sabotage, Theft, etc.)
  - Failed Equipment (Relays, Splice, Transformer, etc.)
  - System Conditions (Transmission, Generation, Loss of load, etc.)
  - Miscellaneous (Software, Vendors, Mis-operations, etc.)

Generation and Transmission Events

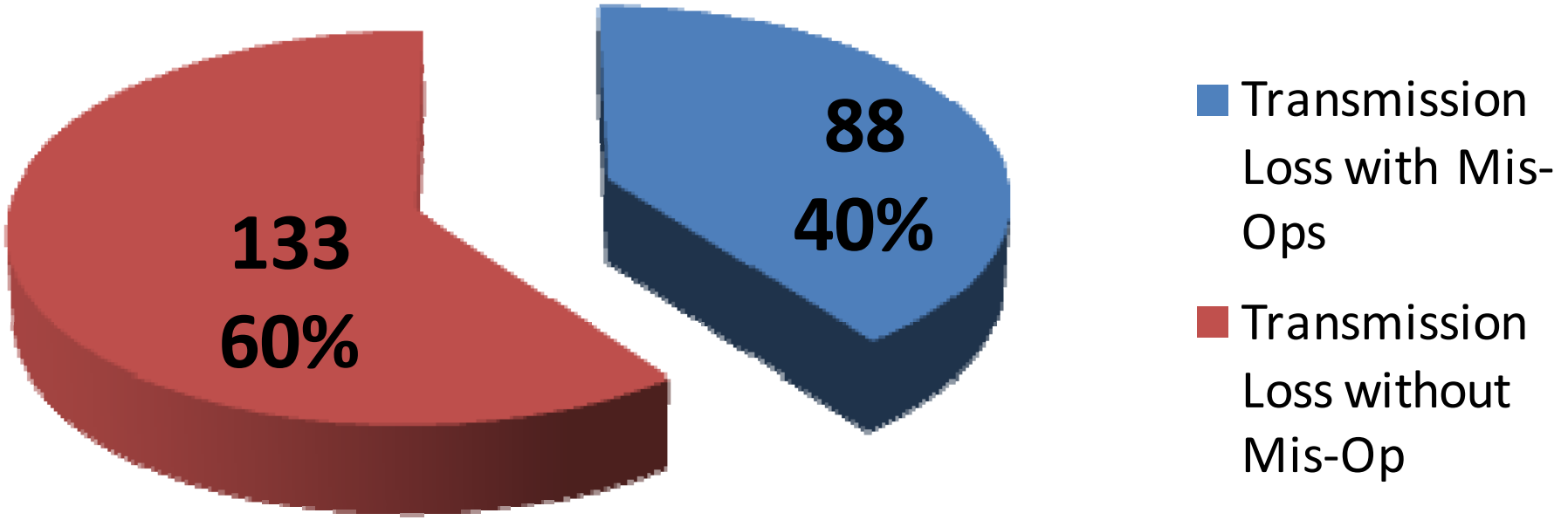


Transmission only

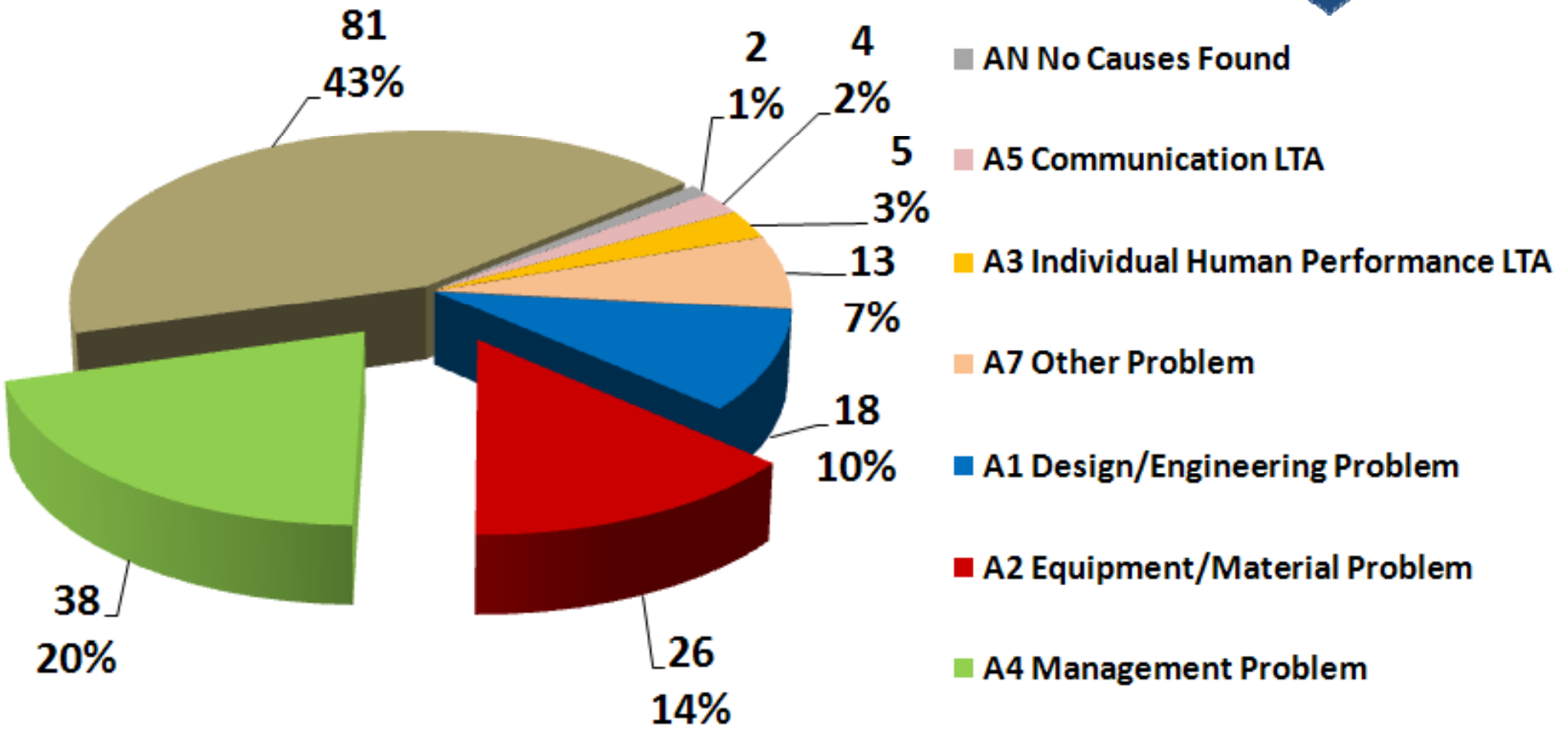
Generation only

Both T & G

Mis-Operations and Transmission Events



Root Cause Determinations



A2 - Equipment/ Material Problem

Deeper Dive into Organizational Issues (Based on Root Cause)

A4 – Management Challenges

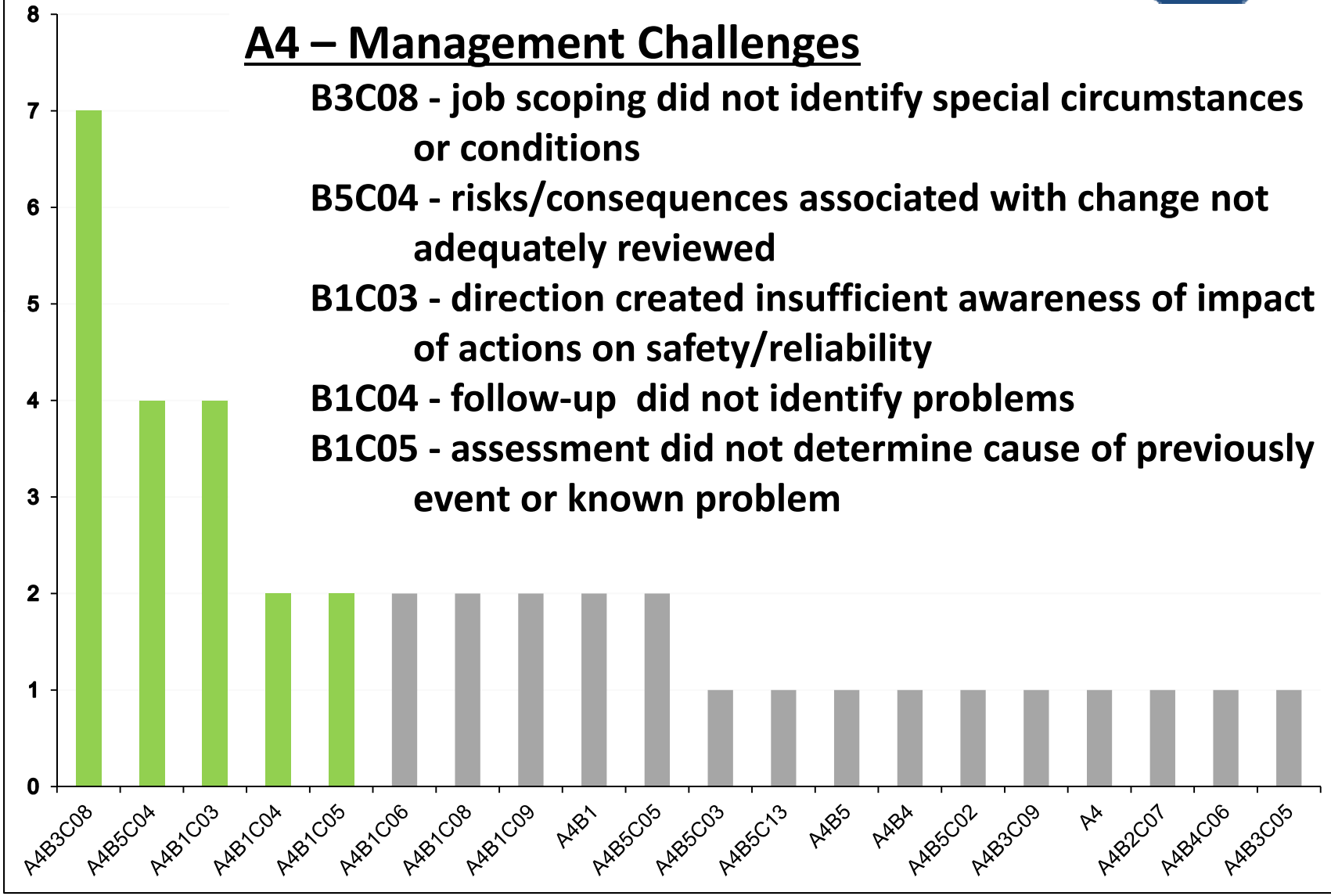
B3C08 - job scoping did not identify special circumstances or conditions

B5C04 - risks/consequences associated with change not adequately reviewed

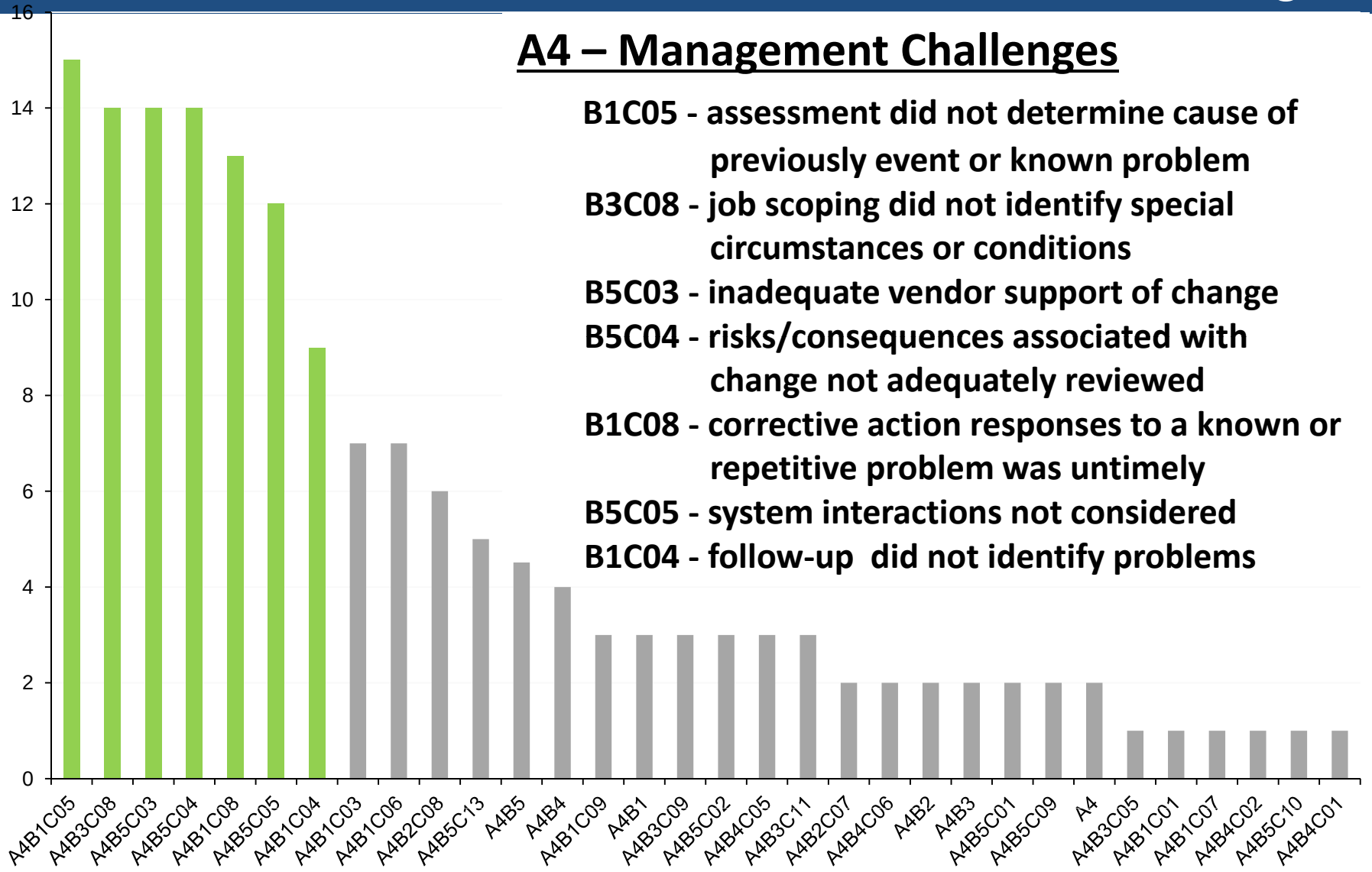
B1C03 - direction created insufficient awareness of impact of actions on safety/reliability

B1C04 - follow-up did not identify problems

B1C05 - assessment did not determine cause of previously event or known problem



All Causes for Management Issues/Challenges



A4 – Management Challenges

B1C05 - assessment did not determine cause of previously event or known problem

B3C08 - job scoping did not identify special circumstances or conditions

B5C03 - inadequate vendor support of change

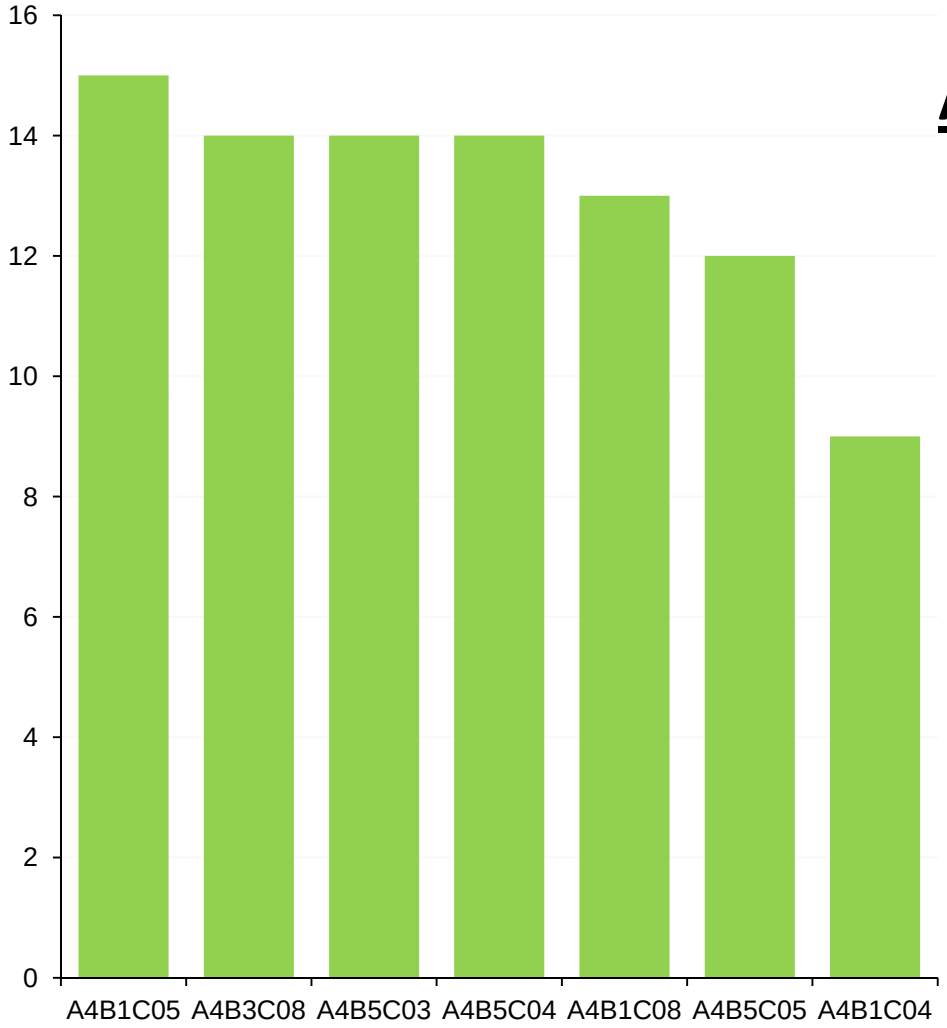
B5C04 - risks/consequences associated with change not adequately reviewed

B1C08 - corrective action responses to a known or repetitive problem was untimely

B5C05 - system interactions not considered

B1C04 - follow-up did not identify problems

All Causes for Management Issues/Challenges



A4 – Management Challenges

B1C05 - assessment did not determine cause of previous event or known problem

B3C08 - job scoping did not identify special circumstances or conditions

B5C03 - inadequate vendor support of change

B5C04 - risks/consequences associated with change not adequately reviewed

B1C08 - corrective action responses to a known or repetitive problem was untimely

B5C05 - system interactions not considered

B1C04 - follow-up did not identify problems

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Summary

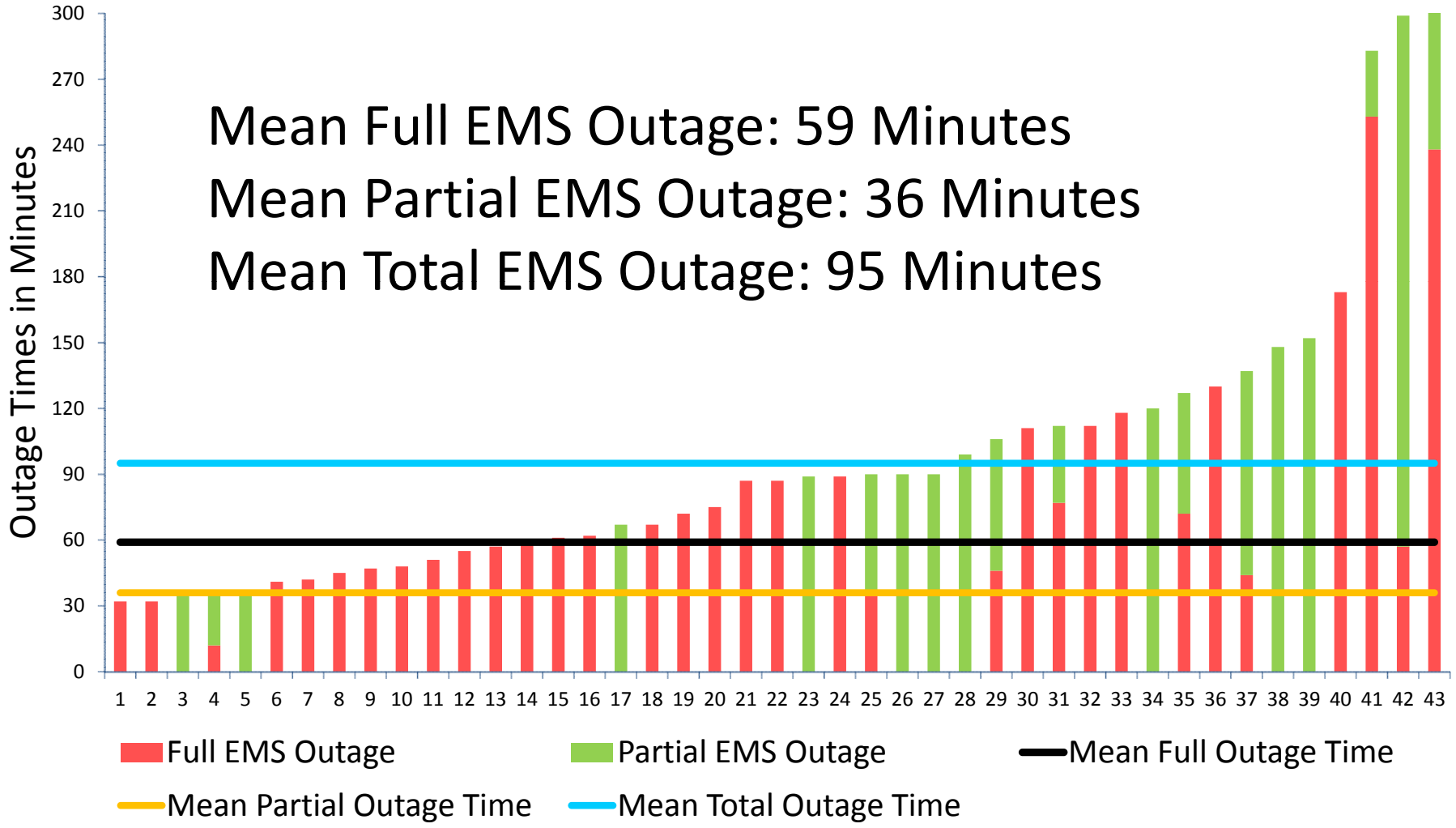
- Less than adequate Job Scoping is a threat to reliability
- Less than adequate EA can result in real threats not being remediated
- Event Analysis process has potential to provide high quality reliability information
- QA/QC of submitted EA reports

Preliminary Analysis of EMS Outages

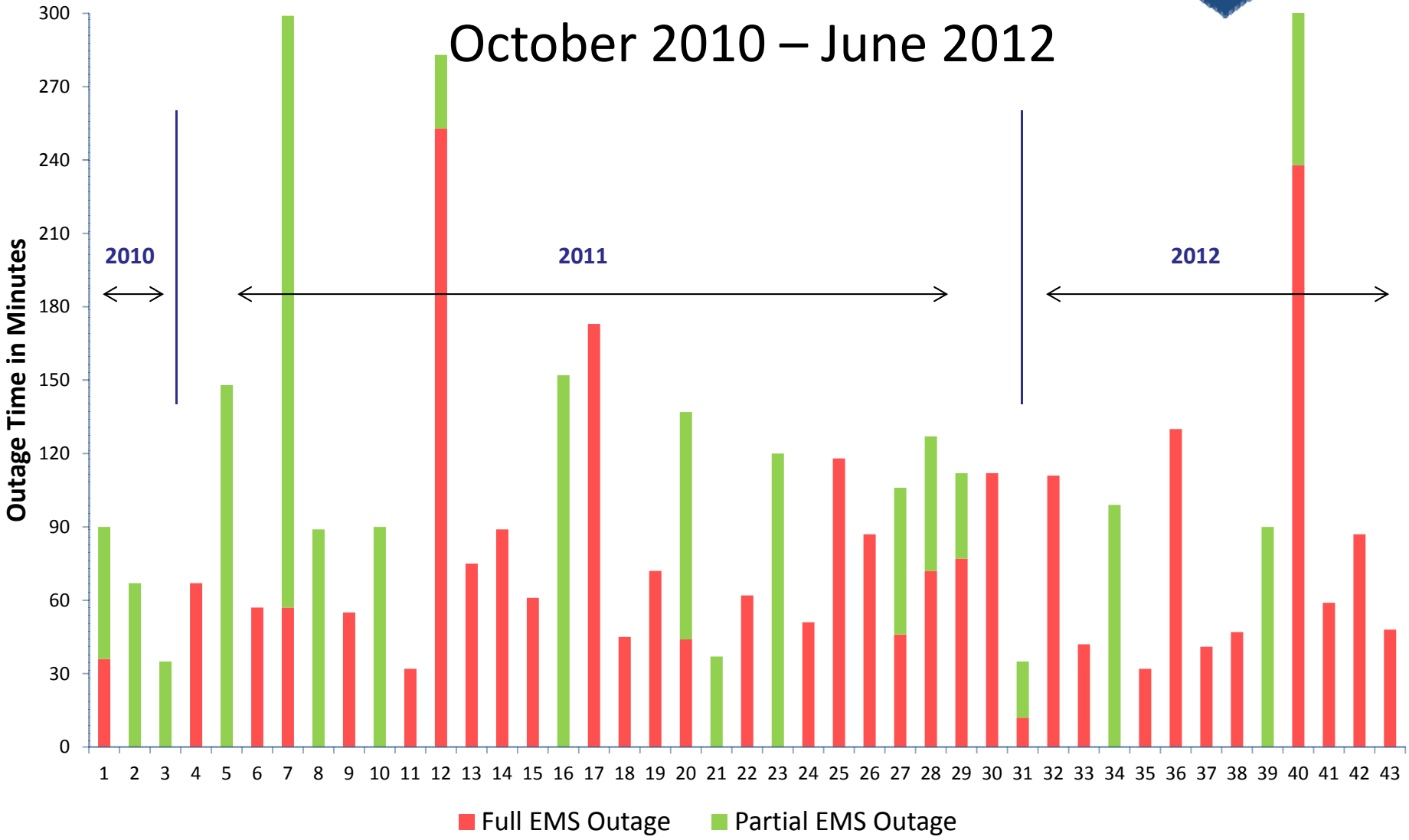
General:

- Category 2b Event
- 46 events (October 26, 2010 – June 27, 2012)
- 35 entities reporting with nine (9) entities experiencing multiple outages
- Complete outages range: **32** to **253** minutes
- Partial outages range: **23** to **242** minutes

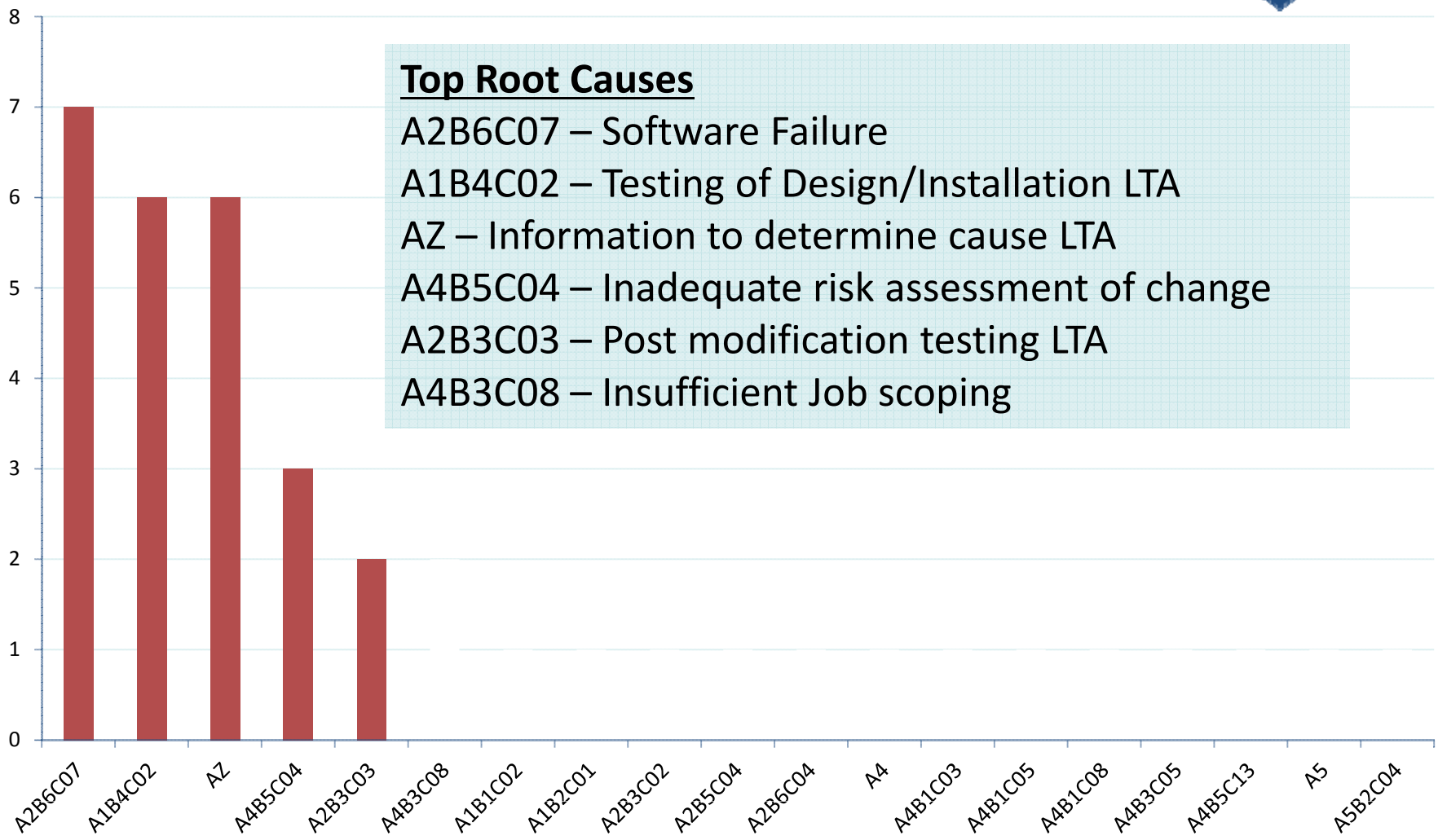
Analysis of Outage Times



Outage Times by Date



Root Cause



Top Root Causes

A2B6C07 – Software Failure

A1B4C02 – Testing of Design/Installation LTA

AZ – Information to determine cause LTA

A4B5C04 – Inadequate risk assessment of change

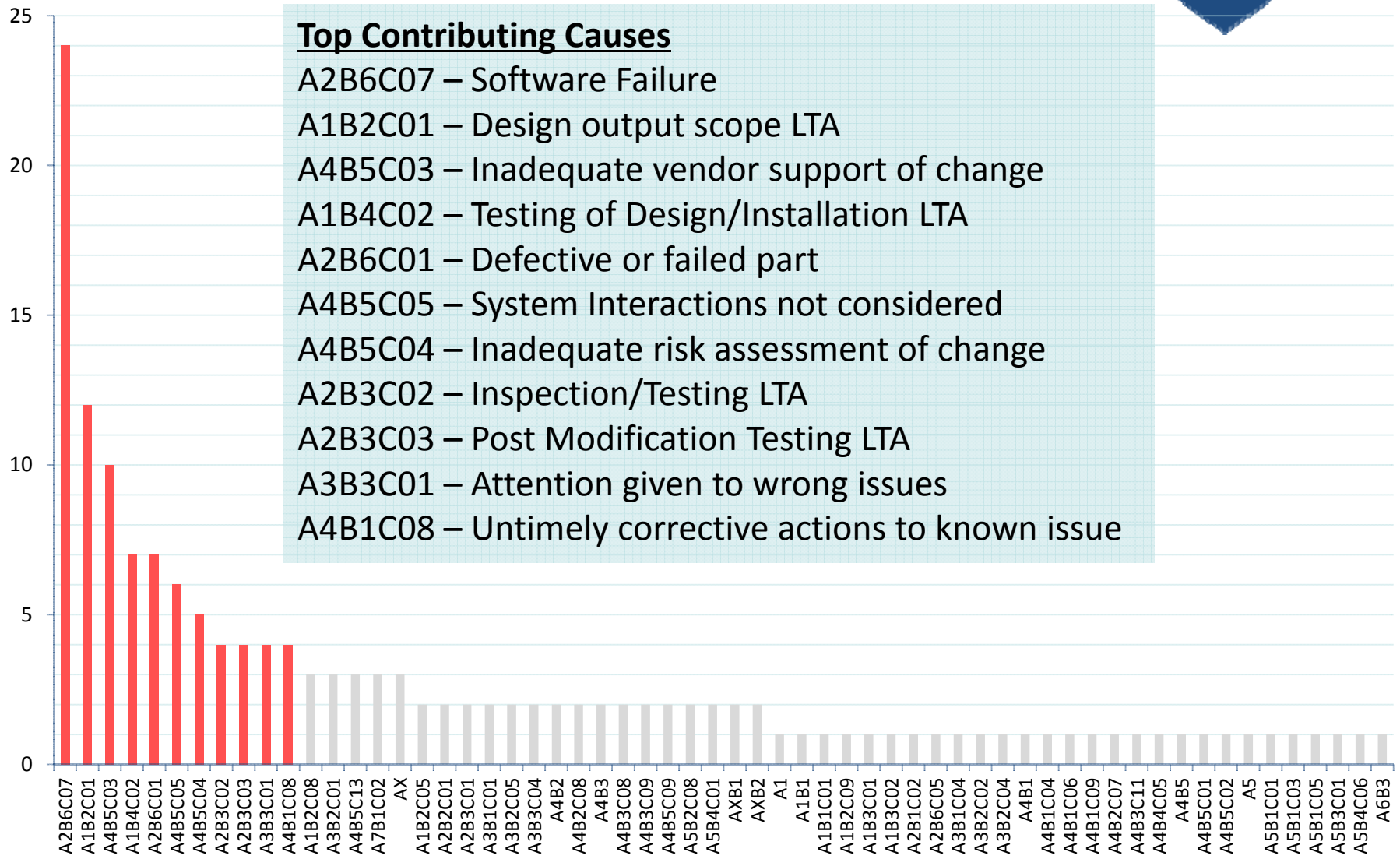
A2B3C03 – Post modification testing LTA

A4B3C08 – Insufficient Job scoping

Contributing Causes

Top Contributing Causes

A2B6C07 – Software Failure
A1B2C01 – Design output scope LTA
A4B5C03 – Inadequate vendor support of change
A1B4C02 – Testing of Design/Installation LTA
A2B6C01 – Defective or failed part
A4B5C05 – System Interactions not considered
A4B5C04 – Inadequate risk assessment of change
A2B3C02 – Inspection/Testing LTA
A2B3C03 – Post Modification Testing LTA
A3B3C01 – Attention given to wrong issues
A4B1C08 – Untimely corrective actions to known issue



Common Themes

Common themes:

1. Software Failures
2. Software Configuration/Installation/Maintenance
3. Hardware Failures
4. Hardware Configuration/Installation/Maintenance
5. Failover Testing Weaknesses
6. Testing Inadequacies
7. Less than Adequate Situational Awareness

Going Forward

Actions to date:

1. Preventable EMS and SCADA Events Alert – April 10, 2012
2. Brief Event Analysis Subcommittee Leadership - December 3, 2012
3. Brief EAS at Operating Committee (OC) Meeting- December 11, 2012
4. Collaboration with EAS EMS Task Force – January 10, 2013

Next steps:

1. More focused analysis
2. Quantifying Risk of EMS outages
3. Update to EAS, OC and Reliability Issues Steering Committee
4. Develop interventions or remediation strategies

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Questions and Answers

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Performance Analysis [Risk Issue 3: Protection Systems]

Jessica Bian, Director of Performance Analysis, NERC

RISC Meeting, January 24, 2013

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Topics

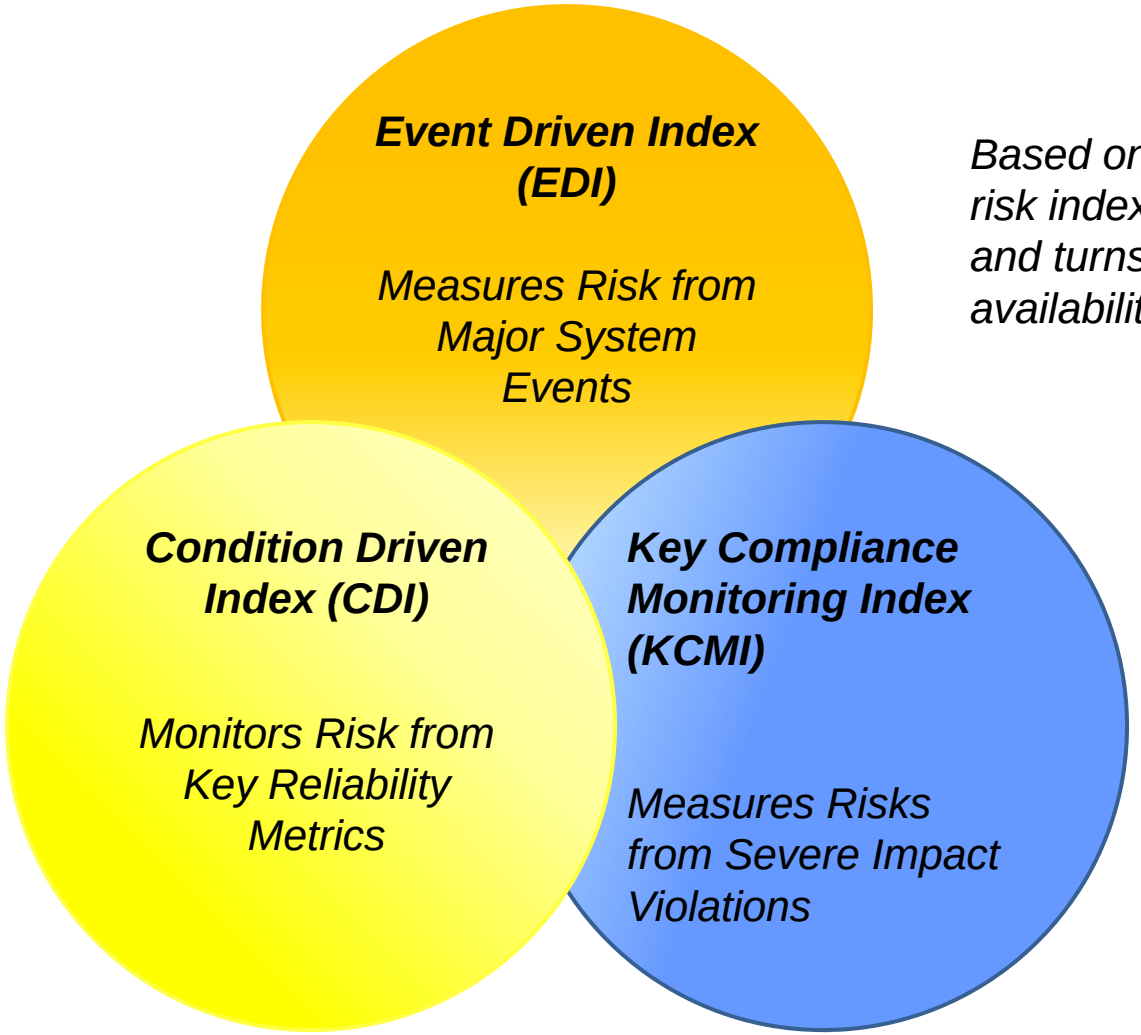
- Risk Measures
- Databases
- Risk Analysis
  - How to identify patterns and risk issues
  - What to effect change
  - How to determine if reliability is improving or deteriorating

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Risk Measures

Risk Measures



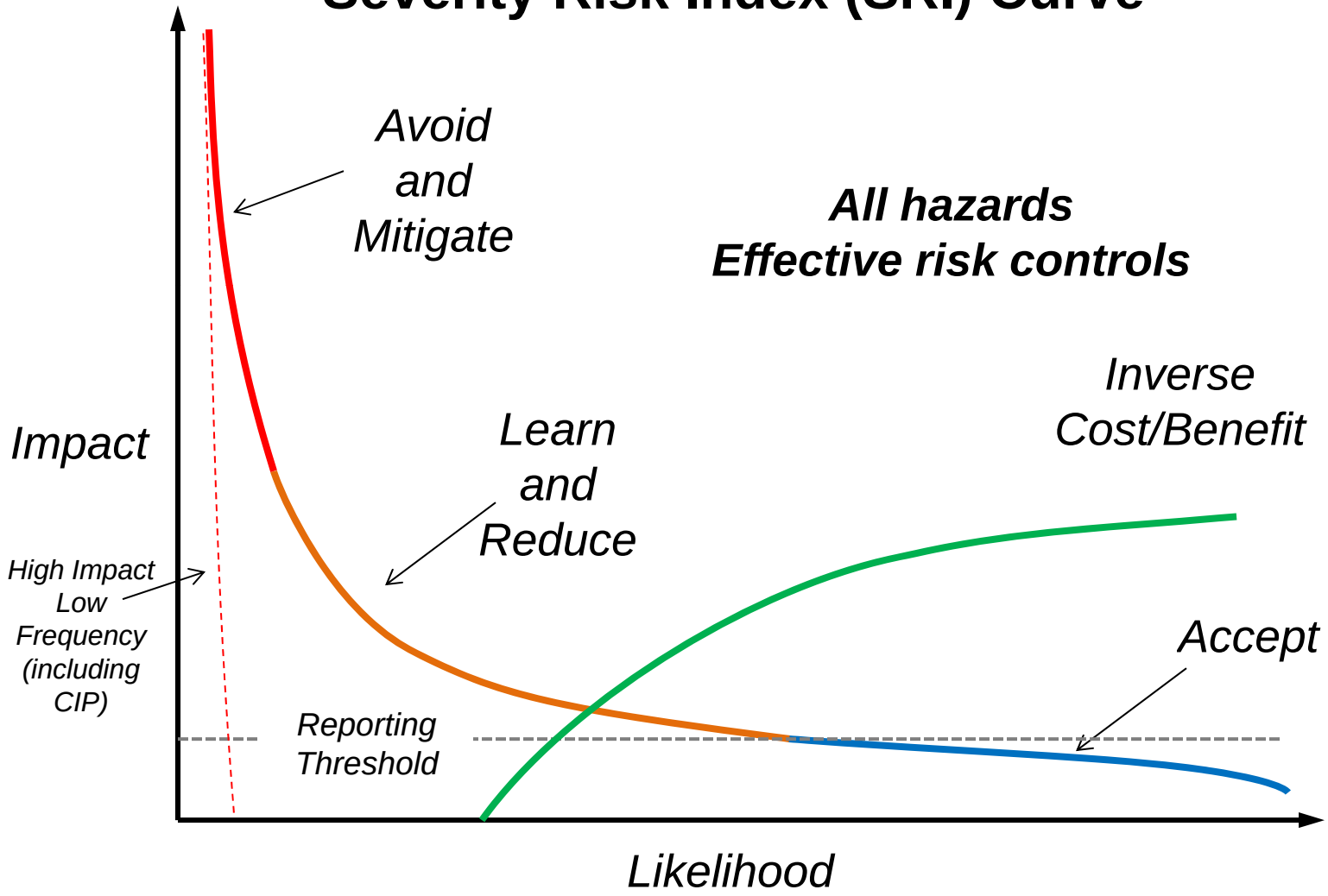
Based on event severity risk index (SRI) values and turns into an availability index

Uses the roster of reliability metrics developed by RMWG/PAS and approved by OC/PC

Identify a subset of standards that have highest impact to reliability and create an index of standards compliance

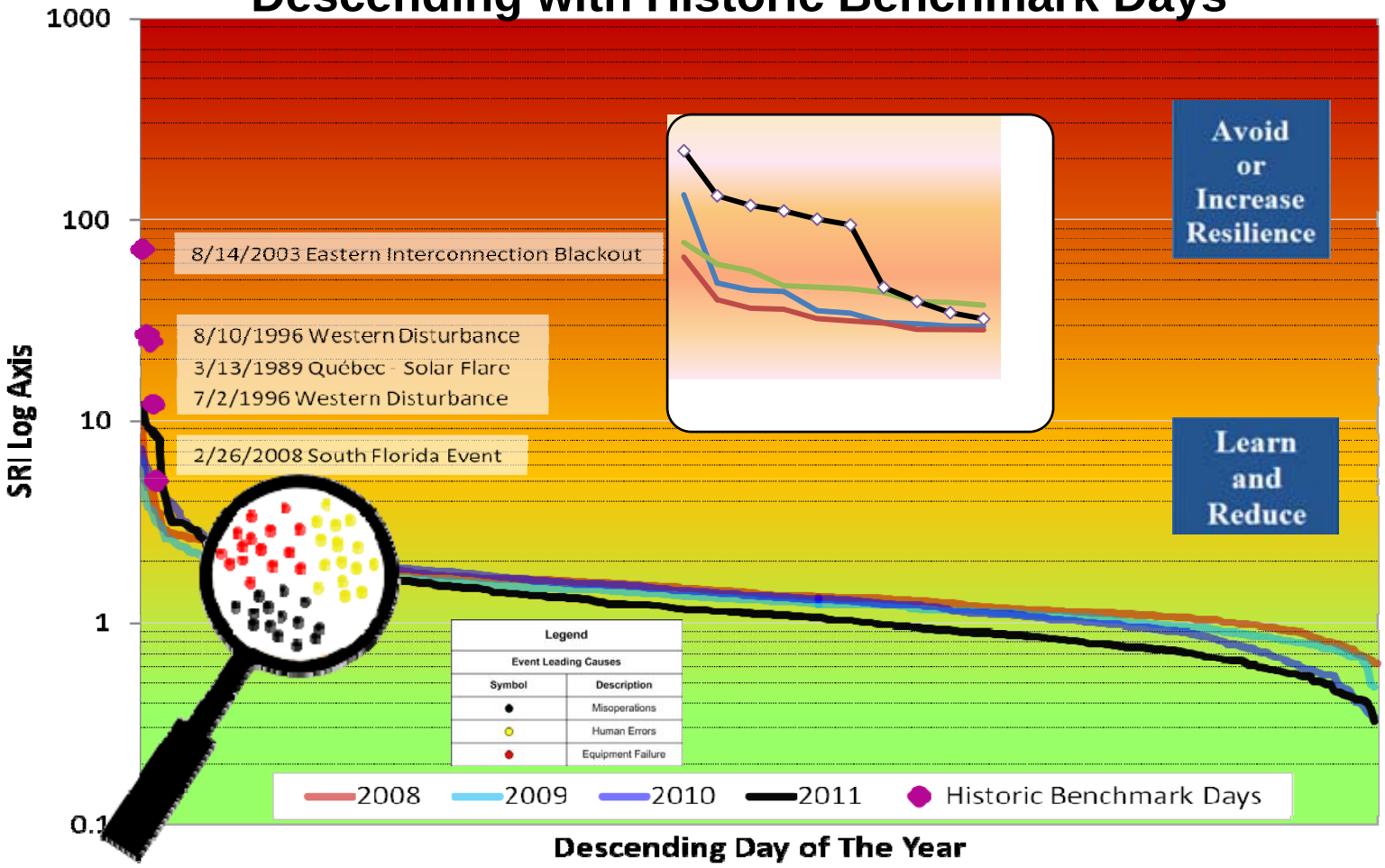
SRI and EDI

Severity Risk Index (SRI) Curve

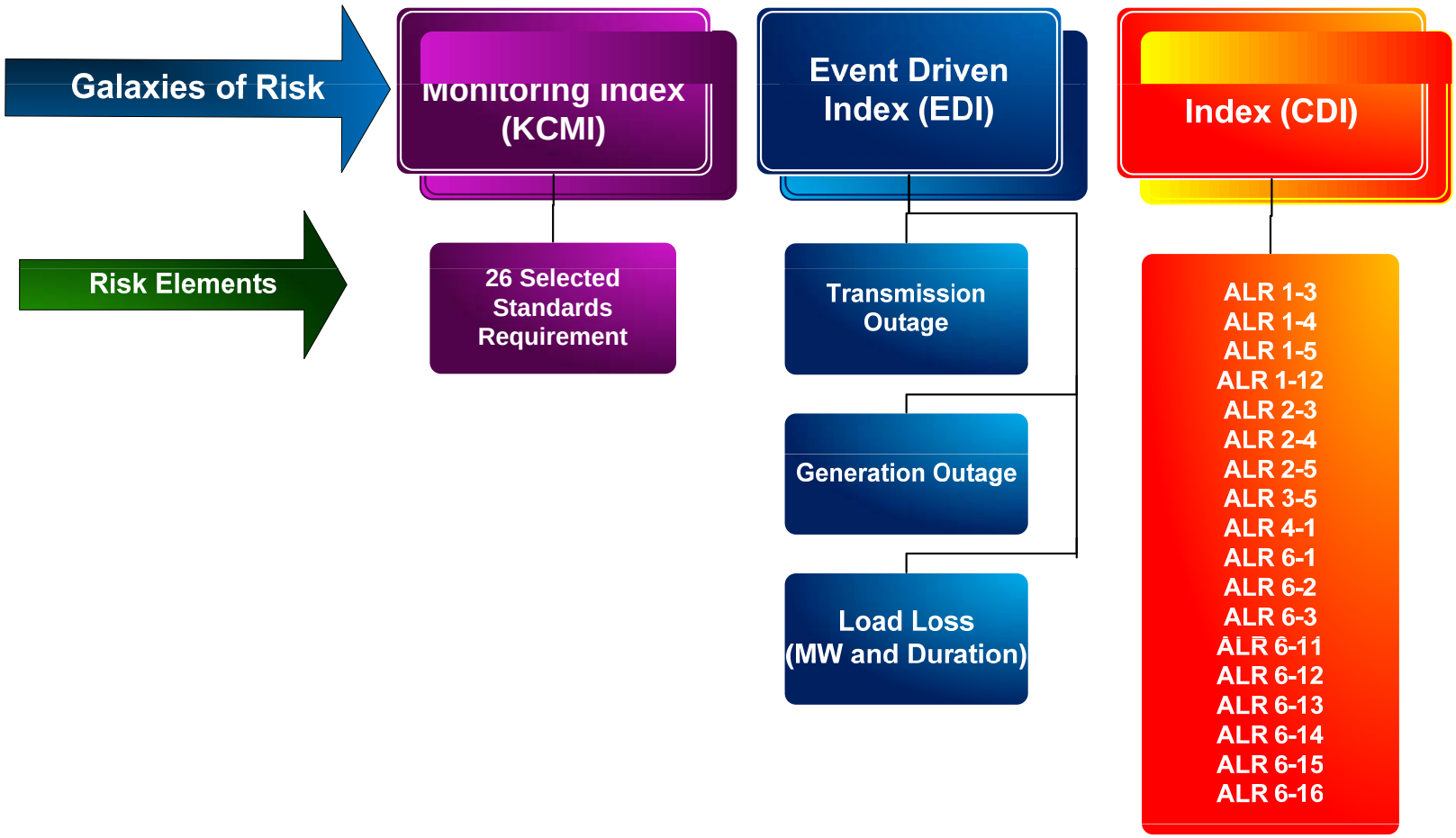


Yearly SRI

NERC Annual Daily Severity Risk Index (SRI) Sorted Descending with Historic Benchmark Days



Tiered Approach



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Reliability Metrics

ALR 1-3	Reserve Margin
ALR 1-4	BPS Transmission Related Events Resulting in Loss of Load
ALR 2-4	Disturbance Control Standard Failures (DCS Failures)
ALR 2-5	Disturbance Control Events Greater than Most Severe Single Contingency (MSSC)
ALR 3-5	IROL/SOL Exceedance
ALR 4-1	Correct Protection System Operations
ALR 6-1	Transmission Constraint Mitigation
ALR 6-2	Energy Emergency Alert 3 (EEA 3)
ALR 6-3	Energy Emergency Alert 2 (EEA 2)

Reliability Metrics (cont'd)

ALR1-5	System Voltage Performance
ALR1-12	Interconnection Frequency Response
ALR2-3	UFLS and UVLS Usage
ALR6-11	Automatic AC Transmission Outages Initiated by Failed Protection System Equipment
ALR6-12	Automatic AC Transmission Outages Initiated by Human Error
ALR6-13	Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment
ALR6-14	Automatic AC Circuit Outages Initiated by Failed AC Circuit Equipment
ALR 6-15	Element Availability Percentage
ALR 6-16	Transmission System Unavailability due to Automatic Outages

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Databases

Reliability Databases

User
Registered Entities
Regional Entities
NERC



Unified Platform
Registration
Graphical User Interface
Security and Alarm
Information Sharing





Violations & Enforcement Records



EOP-004
OE-417
EA Appendices
Event Report
Event Analysis Report



Long-Term and Seasonal Assessments



Transmission Outages and Cause Codes



Generation Outages and Cause Codes



18 Metrics, EDI, CDI, KCMI



Spare Equipment Database



PRC-003 Misop



Demand Response Database

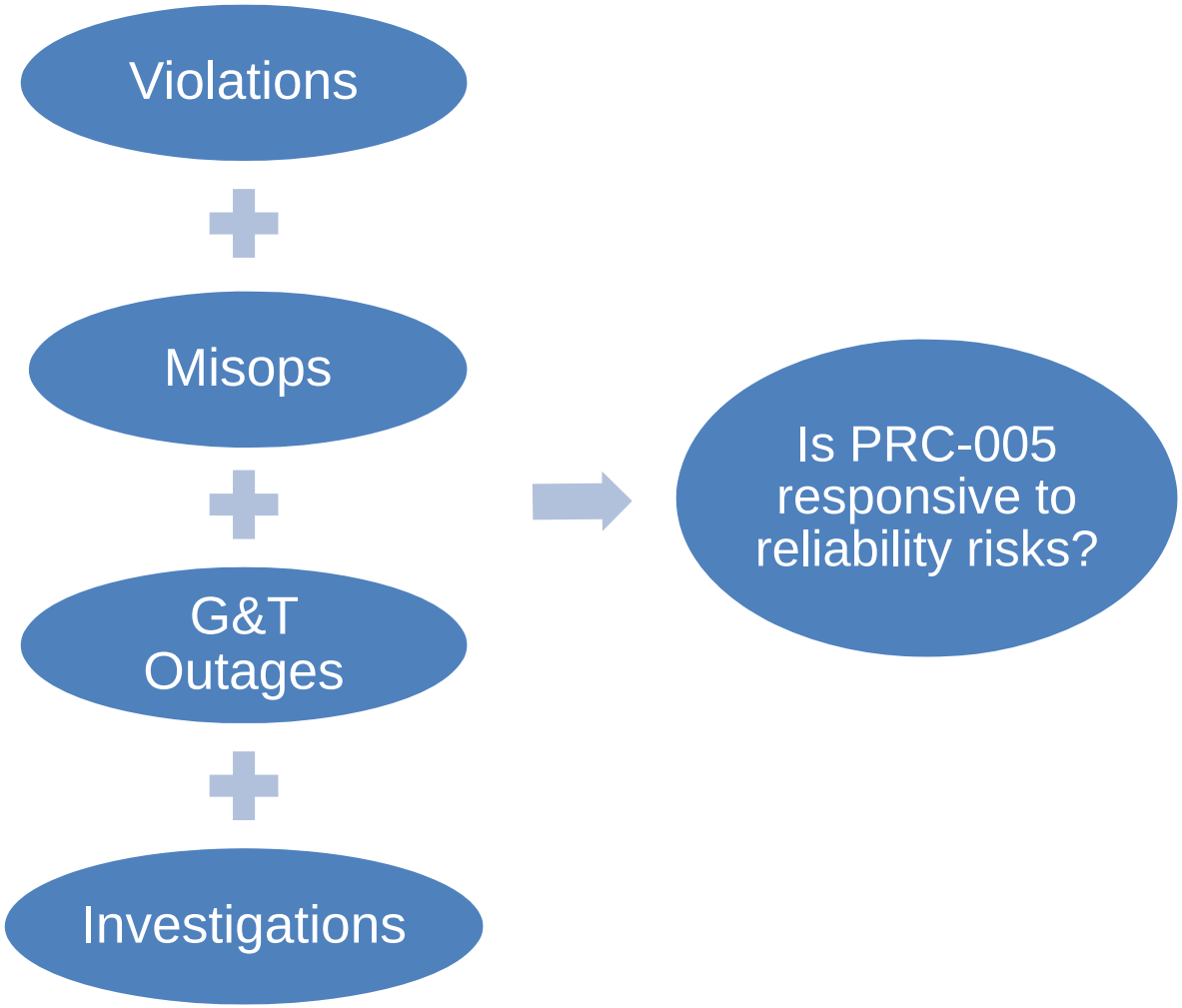


In Production or Design Completed Already



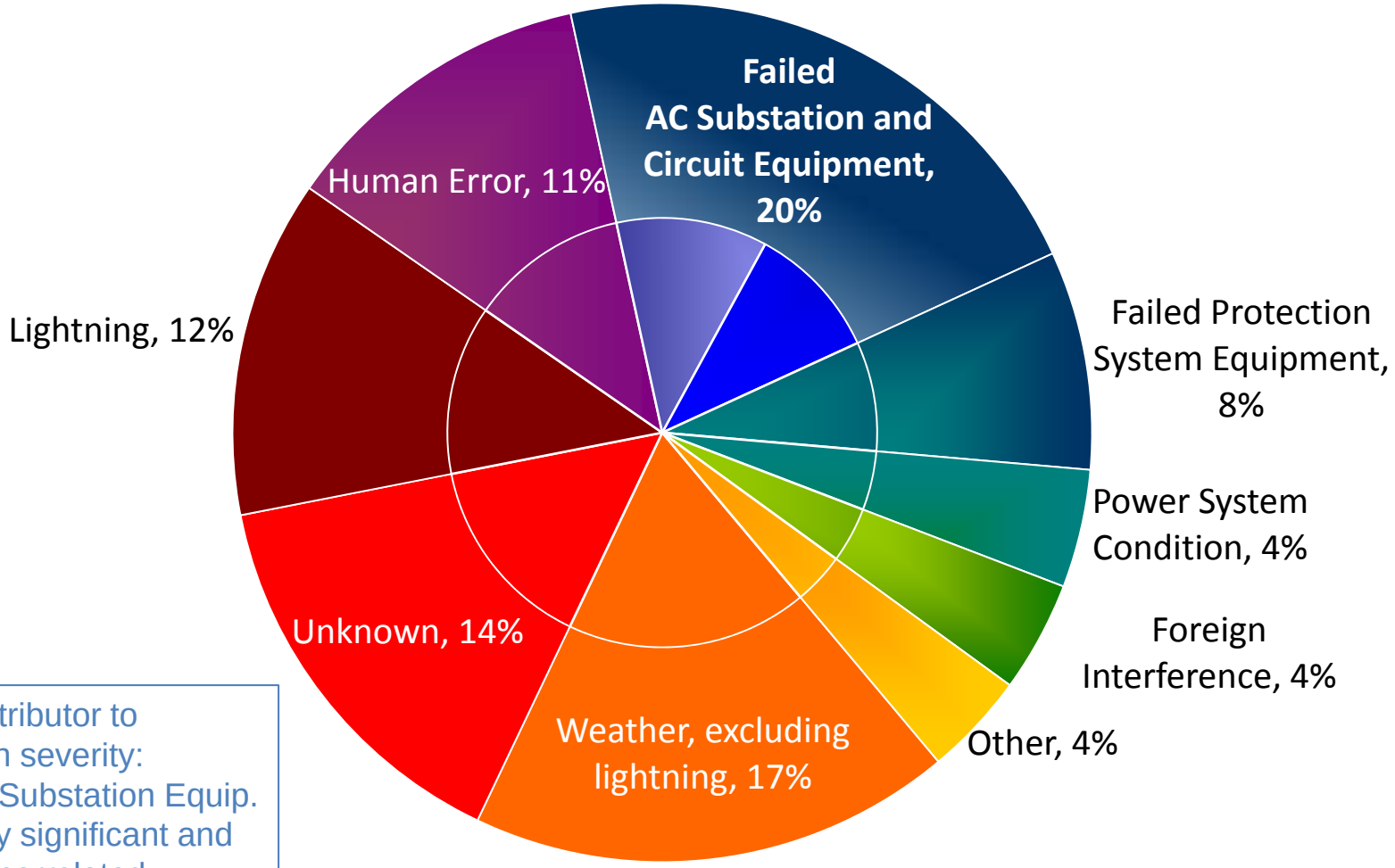
In Conceptual or Design Stage

PRC-005 Study



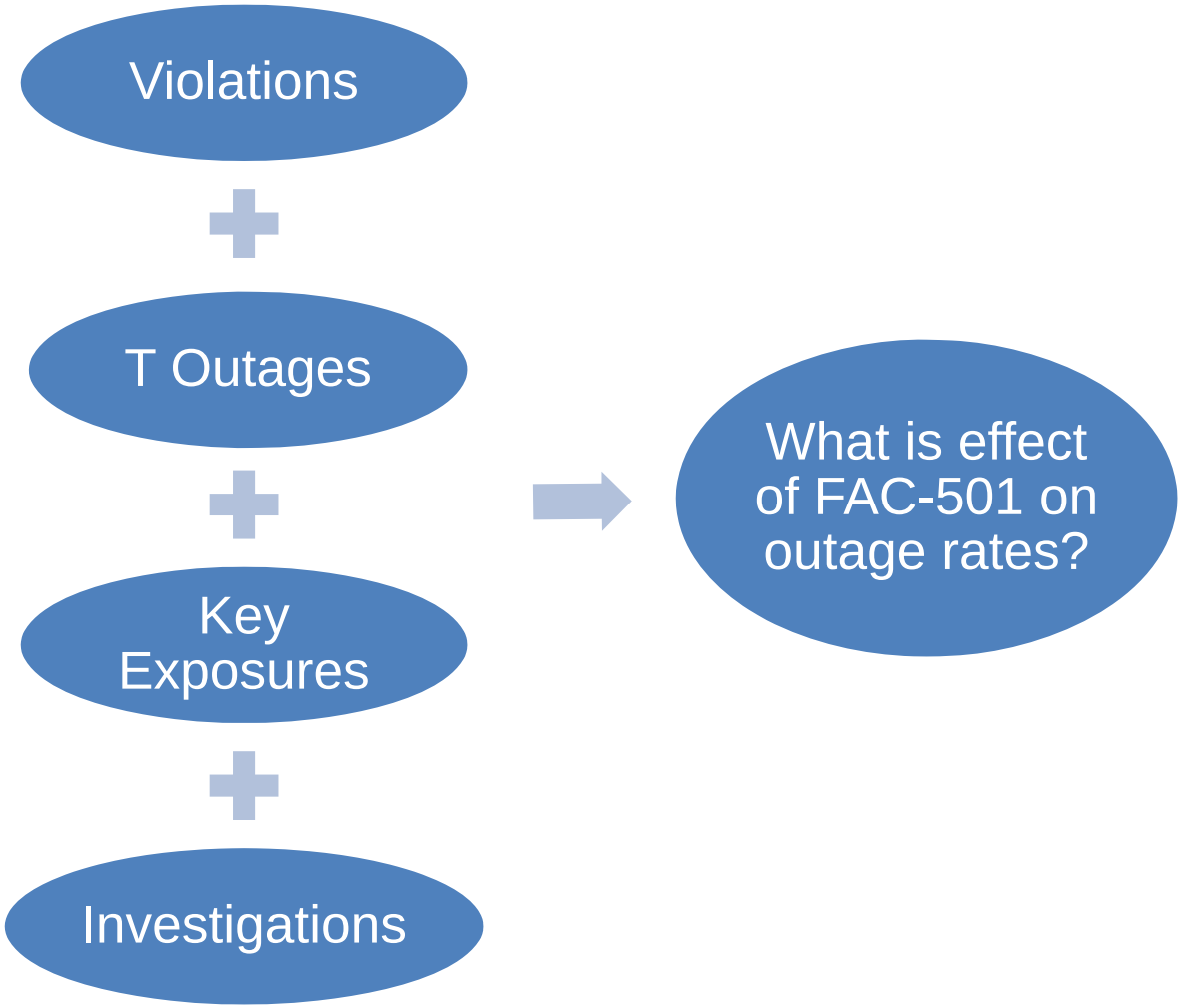
Patterns and Risk Issues

AC Circuit Sustained Automatic Outages by Initiating Cause Code



Biggest contributor to transmission severity:
- Failed AC Substation Equip.
- Statistically significant and positively correlated

WECC FAC-501 Study





Risk Analysis

2011 PRC-005 Study

- 1331 entities applicable to PRC-005
  - 95% of entities had no violations
- Only 3 quarters of misop data (total 2230 misops)
- Preliminary results
  - Correlation between the number of violations and the number of misoperations is NOT statistically significant
  - Correlation between the number of outages and the number of misoperations IS statistically significant ($p<0.0001$)
  - The companies with bigger number of misoperations tend to have more outages.

WECC FAC-501 Study

- Transmission Maintenance Standard FAC-501-WECC-1 implemented on January 1, 2009; a prior regional standard WECC PRC-STD-005-1 on June 18, 2007
  - Applicable elements on transfer paths: 138 AC lines; 2 DC lines; 4 transformers
- Does the standard affect the automatic outage rate? Do the elements with the standard applied have fewer outages than the lines without the standard?
  - Does a mandatory Transmission Maintenance and Inspection Plan (TMIP) lead to improved AC Line Performance?

Analysis Results

- FAC-501-WECC-1 does not result in statistically significant fewer outages on lines where it is implemented
  - except for 15 230 kV lines between 28 to 59 miles
- 62 lines with the Standard applied (45%) have statistically significantly **greater** outage rate than similar lines without the standard

Measure and Results

- ALR6-13 Automatic AC Transmission Outages initiated by Failed AC Substation Equipment
- Benchmark – Average rate reduction over time
  - 20% rate reduction by 2015
- Revise FAC-501-WECC-1 to a results-based standard
  - Establish a performance requirement
  - 90% quantile?

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Future Direction

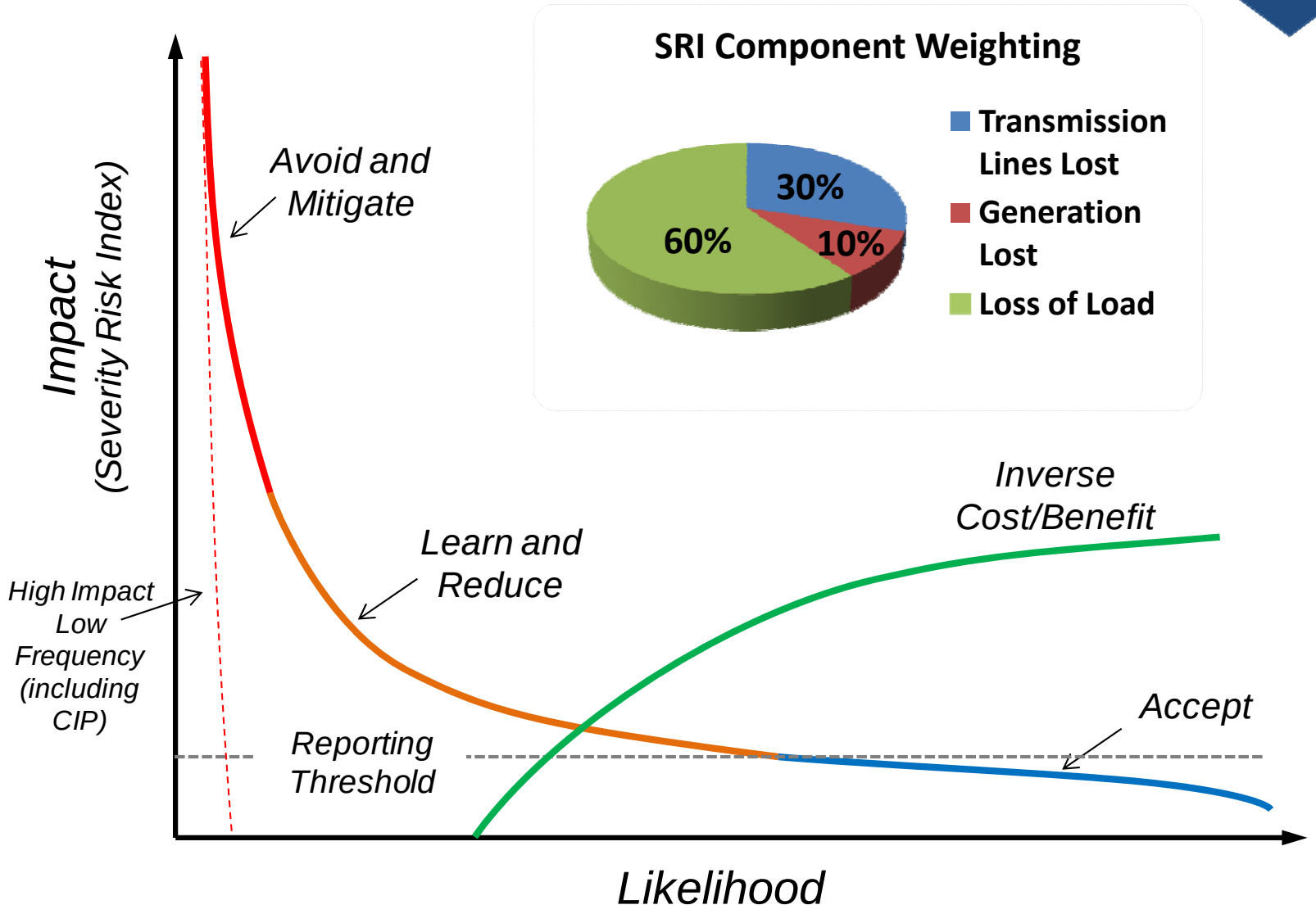
- Add cost-benefit analysis to determine an optimal strategy of the risk reduction
  - Recommend standard changes and prioritization
- Develop a cause-effect reliability risk model
  - Statistically link reliability reduction cause & effect
  - Predict future performance

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Questions and Answers

SRI Calculation



Standard FAC-501-WECC-1

- Title: Transmission Maintenance (FAC-501-WECC-1)
- Purpose –
  - To ensure the Transmission Owner of a transmission path identified in the table titled “Major WECC Transfer Paths in the Bulk Electric System” including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP); and performs and documents maintenance and inspection activities in accordance with the TMIP.
- Transmission line and station maintenance
  - Conductor, insulators, tower, wood pole structure, etc.
  - Breakers, transformers, regulators, reactive devices, etc.

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2014 Business Plan and Budget Schedule

DATES	NERC	Regional Entities	Related Stakeholder-NERC Committee Initiatives
January [TBD] , 2013	Draft 2014-2016 goals, objectives posted for comment.		Kicks off formal process for broad stakeholder input on ERO 2014-2016 goals and objectives; 2014 BP&B priorities
January 24, 2013			Reliability Issues Steering Committee (RISC) meeting
February 1, 2013	Proposed Section 215 written criteria filed with FERC		
February 6-7, 2013	MRC and BOT meetings (San Diego)		
February 2013	Finalize goals, objectives and common assumptions for inclusion in draft 1 of NERC 2014 BP&B to be posted in early May, 2013		
February 12, 2013			Reliability Issues Steering Committee (RISC) Open meeting
March 5-6, 2013			OC/PC/CIPC meetings
March 12, 2013			Reliability Issues Steering Committee (RISC) meeting
March 13-14, 2013			CCC meeting
March 15, 2013	FFT&R Informational Filing at FERC		
April 2, 2013			Trades meeting
April 3 , 2013	Closed FAC Meeting – Review of personnel, contracts and other assumptions for 2013 BP&B		
April 4, 2013			Standards Committee meeting

DATES	NERC	Regional Entities	Related Stakeholder-NERC Committee Initiatives
April 16, 2012			Reliability Issues Steering Committee (RISC) meeting
April 30, 2013		2012 Regional Entity True-Up files due to NERC	
May 2, 2013			Standards Committee meeting
May 3, 2013	Draft #1 of 2014 NERC Business Plan and Budget posted	Draft 1 of RE 2014 Business Plans and Budgets posted on NERC website	
May 3, 2013- 10:00am ET	Conference call and webinar to discuss Draft #1 of 2014 NERC business plan and budget		
May 8, 2013	FAC Meeting- update on 2014 BP&B as part of agenda; quarterly business includes (1) review of year end audited financial statements for NERC and Regions (2) update on 2014 BP&B.		
May 8-9 2013	MRC Meeting-Presentation of Draft 2014 BP&B / BOT meeting (Boston)		
May [date TBD], 2013	Meeting to provide FERC budget staff with overview of 2014 NERC and Regional Entity Business Plans and Budgets		Convene meeting with trades to review and obtain input on 2014 NERC and Regional Entity Business Plans and Budgets
May 22, 2013	FAC conference webinar to review RE 2014 BP&Bs* * (All BOT members invited)	Regional Entities present draft 2014 BP&Bs to NERC FAC	
May 22, 2013			Reliability Issues Steering Committee (RISC) meeting
May 30, 2013	Comments due on 1st Draft of NERC BP&B. NERC and Regional Entity 2012 budget to actual true up filing due at FERC		

DATES	NERC	Regional Entities	Related Stakeholder-NERC Committee Initiatives
June/July 2013		Regional Entity board meeting dates for review and approval of Regional Entity 2014 Business Plans and Budgets SPP – June 18 RFC – June 21 NPCC – June 25 TRE – June 25 FRCC – June 26 WECC – June 26 MRO – June 27 SERC – July 10	
June 5, 2013			Standards Committee meeting
June 10, 2013	Post Draft #2 of 2014 NERC Business Plan and Budget		
June 11-12, 2013			OC/PC/CIPC meetings
June 12, 2013			CCC meeting
June 18, 2013			Reliability Issues Steering Committee (RISC) meeting
July 8, 2013		Final RE 2014 budget submittal due – approved by RE board and final list of LSEs and NEL data	Trades meeting
July 10, 2013			Stakeholder Comments due on 2014 NERC Draft #2
July 11, 2013			Reliability Issues Steering Committee (RISC) meeting
July 18, 2013			Standards Committee meeting

DATES	NERC	Regional Entities	Related Stakeholder-NERC Committee Initiatives
July 19, 2013	FAC webinar to review Draft #2 of 2014 NERC BP&B and final RE budget submittals	REs present final 2014 BP&Bs to NERC FAC	
July 29, 2013	Final 2014 NERC and RE business plans, budgets and assessments posted and mailed to FAC, Board of Trustees and Member Representatives Committee.		
August 8, 2013			Reliability Issues Steering Committee (RISC) meeting
August 12, 2013	FAC Meeting to review and recommend approval of NERC and RE final 2014 business plans, budgets and assessments		
August 14, 2013 (Montreal)	Recap of 2014 BP&B process and discussion of 2015 BP&B Process at MRC meeting		
August 15, 2013 (Montreal)	NERC and RE 2014 business plans, budgets and assessments presented to Board of Trustees for approval.		
August 22, 2013	Standards Committee meeting		
August 23, 2013	Submit package to FERC and Canadian provincial authorities for approval. Package to include: (1) the 2014 NERC and RE business plans and budgets approved by the Board of Trustees, (2) NERC's annual funding requirement (including regional entity costs for delegated functions) and (3) the mechanism for assessing charges to recover that annual funding requirement.		

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Reliability Standard Development Plan

Mark Lauby, Vice President and Director, Standards

Reliability Issues Steering Committee

January 24, 2013

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Rules of Procedure, Section 310

NERC shall:

- develop and provide an annual Reliability Standards Development Plan…to the Applicable Governmental Authorities.
- consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the Plan.
- include a progress report comparing results achieved to the prior year's Plan.

General Timeline

- July
  - solicit stakeholder input
  - review regulatory obligations (directives, 5-year reviews)
  - prioritize projects
- August -September – draft plan, post for stakeholder review
- October – Standards Committee approval
- November – Board approval
- December – file with Applicable Governmental Authorities

2013-2015 Plan – What's New

- Developing a roadmap for standard transformation
- Aggressive plan designed to:
  - expedite transition to clear, concise, world class body of standards
  - bring NERC current on regulatory obligations (directives and 5-year reviews)
- Plan maps projects into three buckets, with one team of standards developers per bucket:
  - Directives
  - Five-year Reviews and Paragraph 81
  - Existing Projects and Emerging Issues
- Timelines depend on extensive informal consensus-building prior to initiating formal development

2014 and Beyond

- 2014 – wrap up projects to address directives, stay current on 5-year reviews
- 2015 and beyond – transition standards program to steady state, maintenance mode
  - Ability to respond proactively to lessons learned, emerging issues
  - Maintain standards through timely completion of periodic reviews
- Continue transformation of Standards

2013 Plan for Paragraph 81

- Of the currently enforceable 105 continent-wide standards:
  - 74 included in 2013 projects (64 scheduled to be complete in 2013, 10 in 2014)
  - 25 revised, consolidated or proposed for retirement in 2012
  - Remaining standards are in various stages of regulatory approval
- All drafting teams to use P81 criteria for standards revised in 2013 (and beyond)
  - Post worksheet with their evaluation of each criterion & drafting team's justification for recommendation
  - NERC to keep and report to industry a running tally of requirements retired, revised, consolidated under P81

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Questions and Answers

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2013 NERC Reliability Assessments

Schedule

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Background

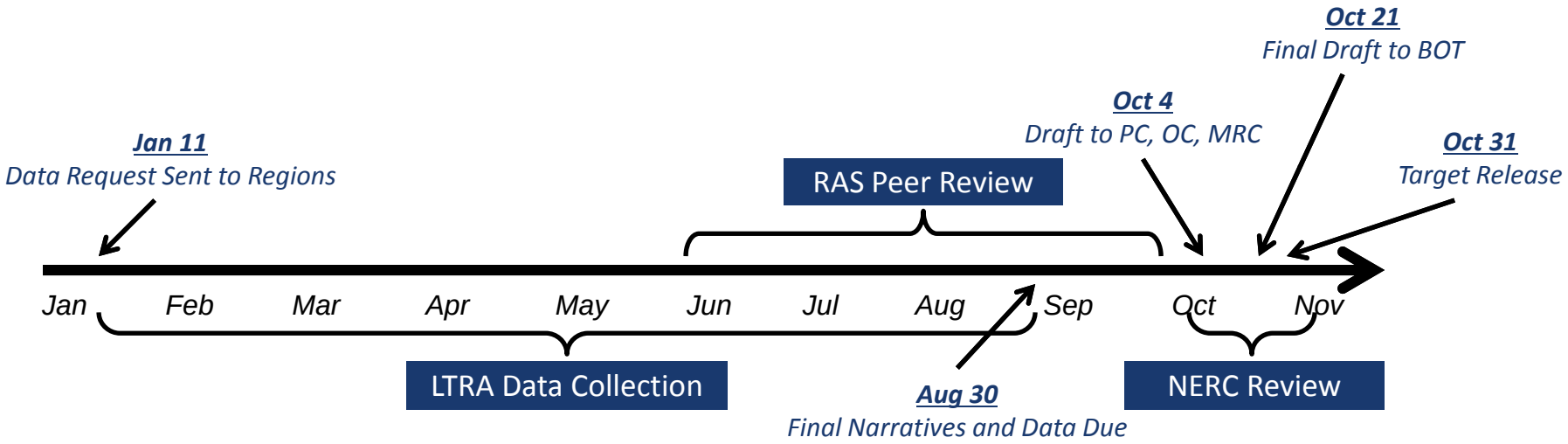
- Peak demand forecasts
- Resource adequacy
- Transmission adequacy
- Key issues and emerging trends impacting reliability
  - Technical challenges
  - Evolving market practices
  - Potential legislation/regulation
- Regional self-assessment
- Ad-hoc special Assessments



2013 LTRA Milestones

Date	Action
Friday, January 11	Data and Narrative Request Sent to Regional Executives
Friday, May 17	Initial Data and Narratives Due to NERC
Friday, May 31	Draft Narratives Posted for Peer Review on RAS Shared Drive
Tuesday-Wednesday, June 18-19	RAS Peer Review Meeting – Newark, NJ
Friday, July 19	Revised Narratives and Corrected Data Due to NERC
Friday, July 26	Complete Draft Posted, RAS Survey to Guide Second Round Peer Reviews
Friday, August 9	RAS Second Peer Review Survey Completed
Monday-Tuesday, August 19-20	RAS Second Round Peer Review Meeting – Halifax, Nova Scotia, Canada
Friday, August 30	Final Data Corrections Due to NERC
Friday, September 6	Assessment Area Sections Released to RAS for Review
Friday, September 20	Complete Report, Including Front Section Released to RAS for Review
Friday, September 27	Final RAS Comments Due / Teleconference to Discuss Entire Assessment
Friday, October 4	Complete Draft Sent to PC, OC, MRC
Friday, October 11	PC, OC, MRC Comments Due to NERC
Monday, October 14	Final Draft (Integrated Comments) Submitted to PC for Approval
Monday, October 14	Final Report Sent to NERC Internal Editor for Review
Wednesday, October 16	Deadline for Planning Committee Email Vote to Approve
Monday, October 21	NERC Internal Editor Completes Review
Monday, October 21	Final Draft Sent to Board of Trustees
Tuesday, October 29	BOT Teleconference
Thursday, October 31	Target Release

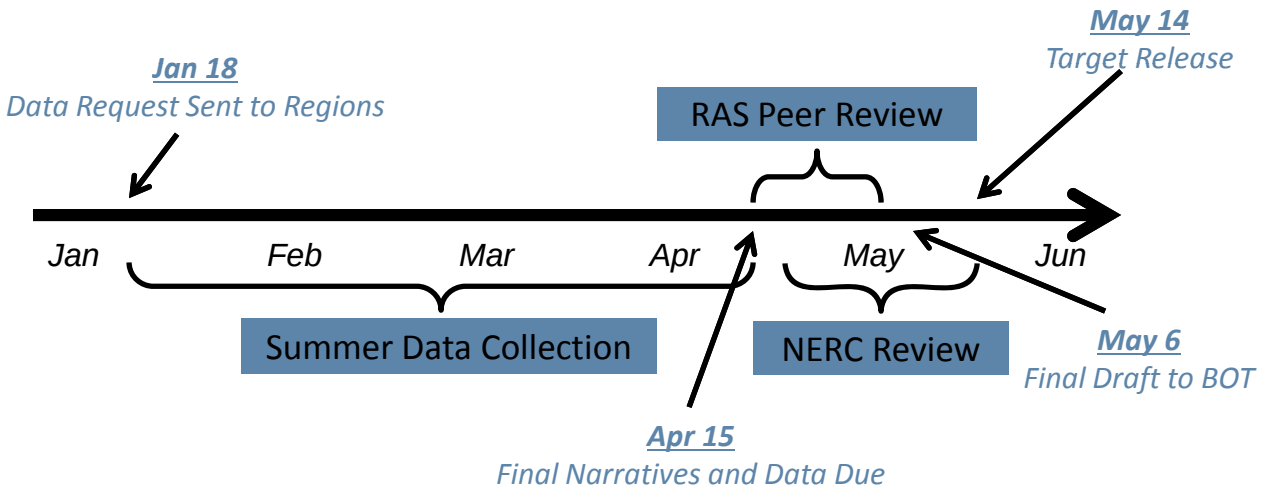
2013 LTRA Schedule



2013 Summer Milestones

Date	Action
Friday, January 18	Data and Narrative Request
Monday, March 25	Initial Assessment Area Data and Narratives Due to NERC
Friday, April 29	Initial draft narratives sent to RAS
Tuesday-Wednesday, April 9-10	RAS Peer Review Meeting
Monday, April 15	Final Narratives and data due to NERC
Thursday, April 18	Draft Complete WRA Sent to RAS
Monday, April 22	RAS Comments due on WRA
Tuesday, April 23	Draft Sent to PC, OC, MRC
Thursday, April 25	PC, OC, MRC Comments Due to NERC
Friday, April 26	Final Draft for Approval sent to Planning Committee
Friday, April 26	Final Draft sent to NERC Editor for Review
Friday, May 3	Planning Committee Voting Completed
Monday, May 6	NERC Editor Review Completed
Monday, May 6	Final Draft Sent to Board of Trustees
Monday, May 13	BOT Teleconference
Tuesday, May 14	Target Release

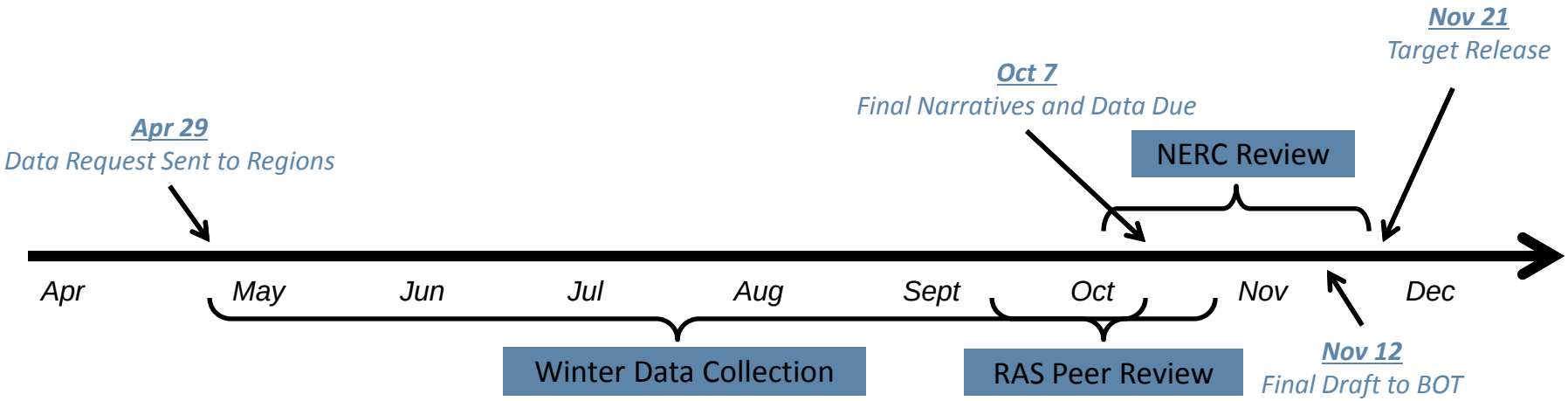
2013 Summer Schedule



2013/2014 Winter Milestones

Date	Action
Friday, April 29	Data and Narrative Request
Monday, September 16	Initial Assessment Area Data and Narratives Due to NERC
Wednesday, September 18	Initial draft narratives sent to RAS
Tuesday-Wednesday, October 1-2	RAS Peer Review Meeting – Austin, TX
Monday, October 7	Final Narratives and data due to NERC
Friday, October 11	Complete Draft of WRA Sent to RAS
Wednesday, October 16	RAS Comments due on WRA
Wednesday, October 23	Draft Sent to PC, OC, MRC
Wednesday, October 30	PC, OC, MRC Comments Due to NERC
Friday, November 1	Final Draft for Approval sent to Planning Committee
Friday, November 1	Final Draft sent to NERC Editor for Review
Tuesday, November 5	Planning Committee Voting Completed
Friday, November 8	NERC Editor Review Completed
Tuesday, November 12	Final Draft Sent to Board of Trustees
Tuesday, November 19	BOT Teleconference
Thursday, November 21	Target Release

2013/2014 Winter Schedule



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Submit by Email

Print Form

Reliability Issues Nomination Form

RRAC RINFv1.06 11.13.2012

NERC bases its operations on four pillars: Reliability, Assurance, Learning and Risk-based Approach. In support of making risk-informed decisions and enabling prioritization of issues, please use this form to submit potential issues (with as much supporting information as you can provide) for consideration by the Reliability Issues Steering Committee (RISC). That group, supported by NERC staff, will work with the industry to help develop overall ERO strategy by identifying and prioritizing the most important reliability issues facing our industry and properly aligning resources to address them. By providing this information, you are helping to ensure the ERO is focusing on the correct priorities as it moves forward.

This form should accept basic formatting pasted from word processing applications, and the form will expand to contain any text larger than the apparent space provided.

First Name:	**Anthony**	**Last Name:**	**Sleva**
Your Title:	**Manager of Electrical Engineering**	**Today's Date:**	**12/31/12**
Organization:	**Altran, 2525 Route 130 South, Cranbury, NJ 08512**		
Email:	**anthony.sleva@altran.com**	**Phone:**	**+1 (503) 718-8905**

Enter (800) 555-1212 as 8005551212

Note: In general, the RISC posts nominations for public review two weeks before each open meeting. Submitters should assume that this nomination will be posted. However, the RISC reserves the right to designate a nomination as confidential to protect critical energy infrastructure information and other information that is sensitive to one or more parties. If you believe your nomination should be considered confidential, please check the box below and provide your rationale for the RISC to consider during its initial evaluation.

☐ I believe this issue should be treated as ***confidential.***

Explanation:

Proposed Reliability Issue

Please explain the issue you are identifying.
What specific action, scenario, or behavior is creating a threat to reliability?

Lack of high speed, time biased, undervoltage load shedding.

Discussion of Possible Harm to Reliability

Please consider the following questions:

1.) ***How does the issue described directly harm reliability****? Does it directly lead to a negative outcome (e.g., a contingency or a loss of the ability to serve load)? Does it have the potential to amplify another problem or make it worse?*

2.) ***What is the scope of the issue****? Is this a North-American issue, an Interconnection-wide issue, a regional issue, or is the scope unknown?*

3.) ***Can you quantify the likely impact?*** *Do you have historical data? Can you estimate values for System Risk Index (SRI) components (generation lost, transmission circuits of various voltage classes lost, load lost for a specific duration)? Can you estimate how it might impact the Condition Driven Index (CDI) metrics*? Are there other ways to describe the possible impact?*

4.) ***How urgent of a concern is this to address?*** *Do you believe it to be an imminent threat that could strike tomorrow, or one that can wait a few months or years? How likely do you think it is that this risk will manifest (for example, a 60% chance it will occur in the next 5 years)?*

Please include or attach all information used to support your conclusions. This should include event analyses, historical data (and an explanation of its source), and any other facts or hard data that help explain the basis for considering this an issue.

The August 2003 Northeast Blackout and the September 2011 Arizona-Southern California Outages were precipitated by short circuits that occurred on transmission lines. Both events could have been avoided if apparent load had been quickly reduced in the affected areas.

Detailed analysis of these events concluded that unforeseen contributing factors occurred and combined to result in widespread electric power outages.

It is our belief that unforeseen events will continue to occur and that corrective actions need to address this possibility. The unforeseen events can be the result of inadequate power system models, inadequate power system oversight, blind spots in protective relaying schemes or a combination of the aforementioned factors.

An example of inadequate power system modeling would be distribution system load models that have not been updated as consumer preferences have changed. During peak summer load conditions, a high percentage of consumer load consists of high torque, low inertia motors that will stall if terminal voltage drops

below 70% for 32 milliseconds or more. Transmission system loading needs to be evaluated for stalled, high torque, low inertia motors served via utility distribution lines in order to demonstrate that motor reacceleration can occur before conditions degrade to the point that grid collapse is imminent.

An example of inadequate power system oversight would be near simultaneous loss of generators in adjacent areas. During storm conditions, it is imprudent to expect that effective communications will be maintained on a real time basis between adjacent Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

An example of blind spots in protective relaying schemes would be multi-unit gas turbine generation stations or combined cycle generating stations equipped with step up transformers that serve more than one generator. Many of these step up transformers are not equipped with overload protection.

For each of the above listed conditions, reactive power shortfalls can occur and voltage control cannot be maintained.

High speed, time biased, undervoltage load shedding can, however, minimize impacts and prevent collapse of the transmission system. Prior to the introduction of microprocessor based protective relays, undervoltage load shedding was problematic because of the number of new relays required, the accuracy of electromechanical devices, and the fact that settings could not be real time biased.

While Standard PRC-023 (Transmission Relay Loadability) minimizes the possibility that protective relays will unnecessarily trip transmission lines during upset conditions, PRC-023 increases the possibility that undervoltage conditions will be maintained until power system collapse occurs.

* SRI and CDI are metrics used by NERC to evaluate overall system performance. For more information, please see the following resources. For SRI: http://www.nerc.com/docs/pc/rmwg/pas/Mar_2012_OCPC/EDI_Whitepaper.pdf and http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf ; for CDI: http://www.nerc.com/docs/pc/rmwg/pas/index_team/CDI_Whitepaper.pdf

Existing Conditions

1. *Is there anything in place that is intended to address this issue already?*
2. *Is there another group or organization currently working to develop solutions?*
3. *Does something exist that is intended to resolve this issue, but it is not 100% effective? If so, please define the gap you see and how to close it.*

Limited undervoltage detection schemes and various special protective schemes have been implemented by some utilities. The effectiveness of these schemes is questionable because the required modeling has not been developed.

Power system load flow models and transient stability models are developed assuming consumer loads are constant resistance or constant power loads, High torque, low inertia loads need to be modeled using bifurcated models that switch load representations from constant power representations to constant impedance representations when motor voltage drops to less than 80%.

The required models need to be developed for a minimum of two conditions, namely: 1.) Three Phase Short Circuits in major metropolitan areas and 2.) Three Phase Short Circuits in areas near (within 50 miles) of

major metropolitan areas.

Suggested Strategy/Actions to Resolve

Please consider the following questions:

1.) ***Do you have ideas how this issue should be addressed****? What actions could be taken to address this issue (development of a whitepaper or guideline, publishing of best practices, offering training, reviewing lessons learned, development of a standard, or other approaches)?*

2.) ***Do the benefits of your suggested solution outweigh the costs?*** *Please provide any cost/benefit information you may have related to your proposed solution.*

3.) ***What does success look like?*** *What kinds of method or metrics would you use to determine if the issue has been resolved?*

This issue should be addressed by the development and issuance of a reliability standard that mandates the modelling of consumer loads as constant impedance, constant power, or high torque, low inertia loads. This reliability standard should be modelled after the requirements for underfrequency load shedding in that yearly updates of distribution line loading must be provided to independent system operators and regional transmission organizations as changes to conustomer loads occur.

This issue can ultimately be resolved by installing static var compensators and high speed switched capacitors to increase var support when transmission system voltage decays as this is a Fault Induced Delayed Voltage Recovery condition.

Alternatively, high speed, time biased, undervoltage load shedding can be enabled using components installed for underfrequency load shedding (at much lower cost). Note that sensitive undervoltage detection schemes are installed in nuclear power plants to initiate load transfers to onsite diesel generators in the event that degraded grid conditions occur.

When these high speed, time biased, undervoltage load shedding schemes are installed, loss of transmission system voltage control will result in occasional scattered widespread outages rather than collapse of wide areas of the power grid.

Please click the "Submit by email" button to automatically generate an email back to NERC with your answers attached. If you have any additional supporting information to include, you will have the opportunity to attach it prior to sending the message.

Submit by Email

Print Form

Thank you for supporting the ERO!

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Submit by Email

Print Form

Reliability Issues Nomination Form

RRAC RINFv1.06 11.13.2012

NERC bases its operations on four pillars: Reliability, Assurance, Learning and Risk-based Approach. In support of making risk-informed decisions and enabling prioritization of issues, please use this form to submit potential issues (with as much supporting information as you can provide) for consideration by the Reliability Issues Steering Committee (RISC). That group, supported by NERC staff, will work with the industry to help develop overall ERO strategy by identifying and prioritizing the most important reliability issues facing our industry and properly aligning resources to address them. By providing this information, you are helping to ensure the ERO is focusing on the correct priorities as it moves forward.

This form should accept basic formatting pasted from word processing applications, and the form will expand to contain any text larger than the apparent space provided.

First Name:	**Jeffrey**	**Last Name:**	**Fenn**
Your Title:	**Director Electrical Engineering/BOD NPCC**	**Today's Date:**	**1/9/13**
Organization:	**SGC Engineering/NPCC**		
Email:	**jfenn@sgceng.com**	**Phone:**	**+1 (207) 866-6555**

Enter (800) 555-1212 as 8005551212

Note: In general, the RISC posts nominations for public review two weeks before each open meeting. Submitters should assume that this nomination will be posted. However, the RISC reserves the right to designate a nomination as confidential to protect critical energy infrastructure information and other information that is sensitive to one or more parties. If you believe your nomination should be considered confidential, please check the box below and provide your rationale for the RISC to consider during its initial evaluation.

☐ I believe this issue should be treated as ***confidential.***

Explanation:

Proposed Reliability Issue

Please explain the issue you are identifying.
What specific action, scenario, or behavior is creating a threat to reliability?

There is a need for a common definition of Critical Energy Infrastructure Information (CEII). The present nationwide description of CEII is extremely vague, allowing the local entities to refine and define to meet the federal guidelines. The result of this is that no one is clear on what is CEII and what is not. In New England each transmission owner has a unique definition, ISO-New England has another and NPCC has yet another. I have experience a distribution company placing CEII on 13.2kV facilities as they felt that they were critical to serving their load (not critical to the integrated transmission system). I have been at regional meetings where similar facilities from different companies were, in one case, CEII, where in another case were not.
As there is no consistent definition nor use of CEII, then the intent of the development for that classification is not been met, resulting in potential reliability issues that drove the original development.
The Scope of this issue is all of North-America.
The urgency of addressing this is dependent on the original intent to define CEII facilities.

Discussion of Possible Harm to Reliability

Please consider the following questions:

1.) ***How does the issue described directly harm reliability****? Does it directly lead to a negative outcome (e.g., a contingency or a loss of the ability to serve load)? Does it have the potential to amplify another problem or make it worse?*

2.) ***What is the scope of the issue****? Is this a North-American issue, an Interconnection-wide issue, a regional issue, or is the scope unknown?*

3.) ***Can you quantify the likely impact?*** *Do you have historical data? Can you estimate values for System Risk Index (SRI) components (generation lost, transmission circuits of various voltage classes lost, load lost for a specific duration)? Can you estimate how it might impact the Condition Driven Index (CDI) metrics*? Are there other ways to describe the possible impact?*

4.) ***How urgent of a concern is this to address?*** *Do you believe it to be an imminent threat that could strike tomorrow, or one that can wait a few months or years? How likely do you think it is that this risk will manifest (for example, a 60% chance it will occur in the next 5 years)?*

Please include or attach all information used to support your conclusions. This should include event analyses, historical data (and an explanation of its source), and any other facts or hard data that help explain the basis for considering this an issue.

There are situations where as long as nuclear facilities are not shown on a map, then the map is not CEII (just a void where most are aware the facilities exist.) There are situations where only BPS (as defined by NPCC) facilities are considered CEII, and then only when detailed information (breakers is usually the criteria, not protection schemes, SPS or other key information) is shown. In other situations one line diagrams are fine at any voltage as long as 115kV and higher (BES plus) breakers are not shown. There are still other situations where general distribution facilities are considered CEII. There is also an interesting situation where some feel that black start units are CEII and cannot be shown, yet, as no one but the ISO is permitted to know what units are black start, it gets rather complicated knowing if a unit is CEII or not, and in some cases, by not showing a unit, it has been identified as being special to those who the CEII is intended to protect from.

* SRI and CDI are metrics used by NERC to evaluate overall system performance. For more information, please see the following resources. For SRI: http://www.nerc.com/docs/pc/rmwg/pas/Mar_2012_OCPC/EDI_Whitepaper.pdf and http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf ; for CDI: http://www.nerc.com/docs/pc/rmwg/pas/index_team/CDI_Whitepaper.pdf

Existing Conditions

1. *Is there anything in place that is intended to address this issue already?*
2. *Is there another group or organization currently working to develop solutions?*
3. *Does something exist that is intended to resolve this issue, but it is not 100% effective? If so, please define the gap you see and how to close it.*

The federal guidelines are in place to attempt to address the definition through vague guidelines, but as has been demonstrated above, are not being applied consistently.
While the issue can be addressed by the RTOs, to date this has not been very successful. While it can be addressed by the reliability councils, to date has not been done. A better solution would seem to be develop a North American standard, complete with examples, that can be used by all of these entities in meeting the original intent of the CEII designation in a consistent manner.

Suggested Strategy/Actions to Resolve

Please consider the following questions:

1.) Do you have ideas how this issue should be addressed*? What actions could be taken to address this issue (development of a whitepaper or guideline, publishing of best practices, offering training, reviewing lessons learned, development of a standard, or other approaches)?*

2.) Do the benefits of your suggested solution outweigh the costs? *Please provide any cost/benefit information you may have related to your proposed solution.*

3.) What does success look like? *What kinds of method or metrics would you use to determine if the issue has been resolved?*

This should be addressed at the North American level so that all players are able to comply consistently. This will not only allow consistency, but protect parties from an audit that is done by someone with a different expectation.
As the cost of compliance is negligible, the cost/benefit should be very low (meaning that benefits far outweigh costs). As with any standard, there is a cost to develop, vote, approve, distribute the standard, but implementation cost would be forward looking and not worth measuring.
Success is a standard that all regions can use consistently and be in full compliance with the intent of the CEII designation.

Please click the "Submit by email" button to automatically generate an email back to NERC with your answers attached. If you have any additional supporting information to include, you will have the opportunity to attach it prior to sending the message.

Submit by Email

Print Form

Thank you for supporting the ERO!

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Agenda – Open Session
Reliability Issues Steering Committee

January 24, 2012 | 12:30pm – 5:00pm

Readytalk Conference
Audio Conference at 1-866-740-1260; Passcode 9473885; Security Code 283714
Web Conference at www.readytalk.com; Passcode 9473885; Security Code 283714

Welcome, Introductions, and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcements

Agenda

1. **Unfinished Items**
   a. **Geomagnetic Disturbance Nomination**
      i. NERC Geomagnetic Disturbance Task Force (GMDTF) Status Update and Work Plan Objectives (30 mins) - Kenneth Donohoo, Oncor Electric Delivery, Director of System Planning Chair, NERC GMDTF
      ii. NERC Operating Committee (OC) Status on Efforts to Develop a Best Practices Report on GMD Preparations and Operating Procedures (15 mins) - Jim Castle, NYISO, Manager of Reliability Compliance and Industry Affairs, Vice Chair, NERC OC
      iii. Request for Phase 2 GMD Task Force Subgroup on Financial Aspects of GMD (5 mins) – Tom Popik, Chairman, Foundation for Resilient Societies
2. **New Items**
   a. **NERC Risk Measurement and Control Tools for High Priority Risk Issues**
      i. Critical Infrastructure [Risk Issue 1: Cyber Attack] – Matt Blizard (30 mins)
      ii. Events Analysis and Human Performance [Risk Issue 2: Workforce Capability and Human Performance] –Mike Moon (30 mins)
      iii. Performance Analysis [Risk Issue 3: Protection Systems] – Jessica Bian (30 mins)

BREAK 2:55pm – 3:10 pm

iv. Situational Awareness [Risk Issue 4: Monitoring and Situational Awareness] – Mike Moon (30 mins)

b. NERC Process Timeline – General Overview (45 mins)

i. The NERC Business Plan and Budgeting process –Michael Walker

ii. The Reliability Standards Development Plan – Mark Lauby

iii. Paragraph 81 Project – Mark Lauby

iv. Reliability Assessments –John Moura

c. New Nominations (20 mins)

RISC discussion of issue nominations received prior to January 9.[1]

i. Under-Voltage Load Shedding

ii. Critical Energy Infrastructure Information

3. Action Item Review (5 mins)

4. Future Meetings (10 mins)

a. February 12, 2013 – Conference Call, 2:00pm – 5:00pm EST

b. March 12, 2013 – Atlanta Meeting, 11am – 4pm EDT

c. April 16, 2013 – Conference Call, 2:00pm – 5:00pm EDT

d. May 9, 2013 – Post-BOT Meeting in Boston, 12:30pm – 2:30pm EDT

e. June 18, 2013 – Chicago Meeting 11am – 4pm CDT

f. July 11, 2013 – Conference Call, 2:00pm – 5:00pm EDT

g. August 15, 2013 – Post-BOT Meeting in Montreal, 12:30pm – 2:30pm EDT

h. September 19, 2013 – Washington, D.C. Meeting 11am – 4pm EDT

i. October 22, 2013 – Conference Call, 2:00pm – 5:00pm EDT

j. November 7, 2013 – Post-BOT Meeting in Atlanta, 12:30pm – 2:30pm EST

k. December – Conference call, date TBD, 2:00pm – 5:00pm EST

5. Adjourn

[1] Any nomination received after this date will be reviewed at a future meeting of the RISC

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Agenda – Open Session
Reliability Issues Steering Committee

February 12, 2013 | 3:00–5:00 p.m. EST

ReadyTalk Conference
Audio Conference at 1-866-740-1260; Passcode 9473885; Security Code 648761
Web Conference at www.readytalk.com; Passcode 9473885; Security Code 648761

Welcome, Introductions, and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcements

Agenda

1. **Board of Trustees Meeting Review and Next Steps**
2. **Action Item Review**
3. **Future Meetings**
   a. March 12, 2013 – Atlanta Meeting, 11:00 a.m.–4:00 p.m. EDT
   b. April 16, 2013 – Conference Call, 2:00–5:00 p.m. EDT
   c. May 9, 2013 – Post-BOT Meeting in Boston, 12:30–2:30 p.m. EDT
   d. June 18, 2013 – Chicago Meeting 11:00 a.m.-4:00 p.m. CDT
   e. July 11, 2013 – Conference Call, 2:00–5:00 p.m. EDT
   f. August 15, 2013 – Post-BOT Meeting in Montreal, 12:30–2:30 p.m. EDT
   g. September 19, 2013 – Washington, D.C. Meeting 11:00 a.m–4:00 p.m. EDT
   h. October 22, 2013 – Conference Call, 2:00–5:00 p.m. EDT
   i. November 7, 2013 – Post-BOT Meeting in Atlanta, 12:30–2:30 p.m. EST
   j. December 16, 2013 (tentative) – Conference call, 2:00pm – 5:00pm EST
4. **Adjourn**

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Industry Webinar

NERC Standard Processes Manual Revisions to Implement SPIG Recommendations

December 6, 2012

RELIABILITY | ACCOUNTABILITY








Background

SPIG Areas of Focus

- The Members Representative Committee formed the Standard Process Input Group (SPIG) to develop recommendations for:
  - Clarity on:
    - Reliability objectives
    - Technical parameters
    - Scope
    - Relative priority of the standards project
  - The standard drafting process and technical content development
  - Standards project management and workflow
  - Formal balloting and commenting

Final SPIG Report

- Five recommendations approved by the Board of Trustees (BOT) in May 2012
- BOT charged NERC Standards Committee (SC) with addressing:
  - 1: American National Standards Institute Accreditation
  - 4: Standards Product Issues
  - 5: Standards Development Process and Resource Issues
- The full report is available on NERC's website

SPIG Recommendation 1

- American National Standards Institute (ANSI):
  - NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.

SPIG Recommendation 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.

SPIG Recommendation 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 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.

SPIG Recommendation 4

- Standards Product Issues:
  - The NERC BOT is encouraged to require that the standards development process address:
    - Use of results-based standards
    - Cost effectiveness of standards and standards development
    - Alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs)
    - Retirement of standards no longer needed to meet an adequate level of reliability

SPIG Recommendation 5

- Standards Development Process and Resource Issues:
  - Improve timely, stakeholder consensus
  - Direct standard development resources toward:
    - Project management
    - Efficient formation and composition of standard drafting teams

SC Implementation

- Standards Committee Process Subcommittee (SCPS) subteams focused on:
  - Streamlining commenting and balloting
    - ANSI requirements
  - Essential elements of a standard
  - Handling “no” votes without comment
- Subteams proposed revisions to the Standard Processes Manual (SPM)

Status

- Draft 1 of SPM Revisions
  - Posted for industry comment June 2012
- Draft 2
  - Revisions made by SCPS in response to comments on Draft 1
  - Posted for comment and initial ballot ending October 2012
  - Initial ballot results: 63 percent approval
- Draft 3
  - Additional revisions made by SCPS to address comments on Draft 2
  - Posted through December 20, 2012 for comment and successive ballot

Key Revisions

- Modifications to streamline the work of drafting teams in responding to comments
- Negative ballots without comments (submitted either individually or as part of a group) count toward quorum but not consensus
- Emphasis on developing informal consensus prior to formal balloting
- Clarification of the handling and purpose of interpretations
- Inclusion of a limited waiver provision



Key Clarifications in Third Draft

Focus of Clarifications

- Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), Measures, and RSAWs
- Handling of Standard Authorization Requests (SARs)
- Treatment of “No” Votes during a final ballot
- Section 16.0 Waiver Provision

VRFs, VSLs, Measures and RSAWs

- Industry supports:
  - Alternatives to VRFs and VSLs
  - Drafting team participation in RSAW development
- NERC and regional compliance and standards staffs are working to develop and implement the Reliability Assurance Initiative (RAI)
- In the interim, measures, VRFs and VSLs will continue to be drafted by drafting teams, with input from compliance staff where appropriate

Handling of SARs

- Clarification of the handling of SARs to facilitate coordination with RISC and NERC standing technical committees

Treatment of "No" Votes During a Final Ballot

- Concern about handling of "no" votes during final ballot because comments are not accepted during final ballots
  - New proposed SPM does not count "no" votes submitted without a comment towards consensus
- Language added to clarify that all "no" votes submitted in a final ballot will count toward quorum and consensus

Section 16.0 Waiver

- Concern expressed about transparency, openness and due process protections
- SCPS incorporated:
  - Notice period for stakeholders prior to SC's consideration of a waiver request
  - Clarification of how notice will be provided
  - Requirement that SC immediately report waivers to the Standards Oversight and Technology Committee



Next Steps

Key Dates

- **November 21 – December 20, 2012:** Comment Period
- **December 11-20, 2012:** Successive Ballot
- **January 2013:** Recirculation Ballot
- **February 2013**: Presentation to NERC BOT

SPM Revisions Project Page:
http://www.nerc.com/filez/standards/Standards_Processes_Manual_revisions_SPIG_2012.html

Standards Reform

- NERC BOT Adopted Four-Part Resolution (November 2012):
  - Accountability
  - Drafting team composition
  - Workflow/process
  - Work Plan (Reliability Standards Development Plan or RSDP)
- Additional changes being considered by SPIG
  - SPIG has been reconvened to assess status

Changes to Date

- Leadership and Staff Changes
  - Standards department reorganization
- Assessing Compliance
  - Reliability Assurance Initiative (RAI)
  - Drafting RSAWs during standards development
- Standing up RISC

Ultimate Goal

- Focus on Reliability
  - Ensure that industry resources invested to develop standards are worthy of the output: *a stable body of world-class reliability standards*
- Industry feedback and support has been and will continue to be instrumental

Contacts

Laura Hussey, NERC Director of Standards Development

laura.hussey@nerc.net

Stacey Tyrewala, NERC Attorney

stacey.tyrewala@nerc.net

Allen Mosher, Standards Committee Chair

amosher@publicpower.org



Questions?

Draft Agenda
Standards Committee

December 13, 2012 | 1:00 p.m. – 5:00 p.m. ET
Phone Number: 1-866-740-1260
Meeting Code: 5247071
Security Code: 1234321

Introductions and Chair's Remarks
NERC Antitrust Compliance Guidelines *
Done
Public Announcement *
Done
SC Expectations *

Quorum obtained.

Agenda

1. **Review of Agenda (Approve)**

Additions requested:
John Bussman requested clarification on SPM. Will be discussed on the strategic plan agenda item.
Also 2 items added to 4a: 2010-14.1 and 2007-…
6d added report from nominating committee.
Agenda approved with modification.

c. **Waiver of 5-day Rule (Approve)**

Approved.

c. **Consent Agenda (Approve)**

c. October 4, 2012 Standards Committee's Executive Committee Meeting Minutes* **(Ratify)**

b. November 8, 2012 Standards Committee Meeting Minutes* **(Approve)**

c. November 19, 2012 Standards Committee's Executive Committee Meeting Minutes* **(Ratify)**

Approved.

4. Projects under Active Development (Review)

a. Status of Projects Under Active Development*
• Update on Project 2010-17 Definition of BES (P. Heidrich)

- *Project 2006-06 Reliability Coordination*
  NERC Legal is working on the draft petition.

The remaining standard for this project is IRO-003-2, which the drafting team tabled in early January 2012 to focus on moving the other standards forward. As part of the 2013-2015 Reliability Standards Development Plan, this standard will be reviewed as part of a comprehensive review of the IRO family of standards to ensure that NERC is current on 5-year reviews and has met outstanding FERC directives.

- *Project 2007-03: Real-time Operations r0*
  NERC Legal is working on the draft petition.

- *Project 2007-09 Generator Verification*
  MOD-025, MOD-027 and PRC-019: The standards were posted for a 45-day formal comment period and concurrent initial ballot period from February 29 through April 16. The team met May 15-17 and developed responses to comments and revisions to the standards. The team worked with QR to respond to their comments and re-submitted the documents July 26. The posting schedule was determined during the August 9, 2012 SC meeting for this project. The standards were posted for a formal comment period and successive ballot, which ended on October 31, 2012. Each standard achieved a quorum and passed the ballot. The team is responding to comments and will plan to proceed to a recirculation ballot for these three standards.
  MOD-026 and PRC-024: The standards were posted for a 30 day formal comment period and successive ballot between February 29th and March 29th. The team met May 15-17 and developed responses to comments and revisions to the standards. The team worked with QR to respond to their comments and re-submitted the documents July 26. The posting schedule was determined during the August 9, 2012 SC meeting for this project. The standards were posted for a formal comment period and successive ballot, which ended on October 31, 2012. MOD-026 failed to reach a quorum, so the ballot was extended. MOD-026 passed the ballot, but PRC-024 failed. The team is responding to comments and will proceed to recirculation for MOD-026 and will pursue a successive ballot for PRC-024.
  A coordination issue with RFC standards MOD-024 and MOD-025 is being addressed. RFC is withholding filing of their MOD-024 and MOD-025 standards until the continent-wide standard MOD-025 is approved. They will then evaluate whether the continent-wide standard meets their needs.

  Alice's report: Large team divided into sub-groups. Most comments and negative votes are for R5. SDT agreed to remove it.
  On PRC-24 objections from FERC staff on VSLs. More discussion on-going.

- *Project 2010-07: Generator Requirements at the Transmission Interface*
  FAC-001-1 and PRC-004-2.1a were adopted by the BOT on February 9, 2012. PRC-005-1.1b and FAC-003-3 were adopted by the BOT on May 9, 2012. The legal

petition, which incorporated all of the standards, was filed with FERC on July 30, 2012.

- *Project 2010-13.2 Generator Relay Loadability*
  The project is 15 weeks behind its planned delivery because the draft standard during its informal development did not meet the results-based standard (RBS) criteria; and during the rewrite, the team determined additional technical analysis was necessary to improve the clarity of the required performance that would have been revealed by industry stakeholders, resulting in additional schedule slide. The team is working diligently to compress the schedule as much as possible and will assess the feasibility of achieving the filing deadline (September 30, 2013) following the initial ballot posting in early 2013. Pre-emptively, the team is holding a second meeting December 11-14 2012 in Atlanta to continue addressing stakeholder comments and other components of the project, such as, VSL justifications, RSAW development, and mitigation of identified risks to the project revealed in the comments or by the team.

- *Project 2010-17 Definition of BES Phase 2*
  Phase 2 is well underway. The Planning Committee is taking the lead on investigating threshold limits. The PC has been given a deadline of December 20, 2012 for the completion of its work and will finalize the report at its December meeting.
  FERC issued a NOPR on Phase 1 on June 21, 2012. Responses were filed on September 4, 2012.
  There were issues at the PC meeting discussion. PC deferred approval to January. Still on schedule but potential for delay. PC went beyond scope in regards to what was requested which was not fully vetted by the entire PC. If PC introduces new concepts the schedule may be delayed in order to give time to consider them. For the time being Final report made available to PC members (in PC meeting material). Will be posted in the project web page at a later date.

- *Project 2010-INT-01 Interpretation of TOP-006-2 for FMPP*
  BOT adopted at the November 2012 meeting. It should be filed shortly.

- *Project 2011-INT-01 Interpretation of MOD-028 for Florida Power & Light Company*
  Rapid Revision Pilot
  Approved at the February Board of Trustees meeting. Filed with FERC on 8/24/2012.

- *Project 2011-INT-02 Interpretation of VAR-002 for Constellation Power Gen*
  This Interpretation Request was approved by the SC for Rapid Revision on Jan 12, 2012. The team held two conference calls the week of April 9-13 to discuss comments received and determine the next step for the standard. The team has

completed developing responses to comments and made conforming revisions to the standard for QR on April 26.
The documents were submitted to QR on April 30. The team received feedback from QR and made appropriate revisions to the documents and resubmitted them for posting on May 15.
The draft standard was posted for a 30-day successive ballot and comment period on May 22; and due to a technical issue the posting was extended to June 27. The standard achieved a quorum and passed the successive ballot.
The team held a conference call on July 2 to discuss the comments received on the ballot and prepare for the recirculation ballot. The team developed responses to comments and revised the VSLs for Requirement R2. The Consideration of Comments and revised standard were submitted July 9 for posting. The standard was posted for recirculation from July 18 to July 27 and received enough support to pass the ballot.
The proposed standard was presented to the NERC BOT at the August 16th meeting and approved. NERC Legal staff submitted the regulatory filing to FERC on November 21st.

- *Project 2012-08.1 Glossary Updates Phase 1:Statutory Definitions*
  The SAR for adding the definitions for Bulk Power System, Reliable Operation, and Reliability Standard to the Glossary of Terms Used in Reliability Standards was posted for a 45-day formal comment period from June 19 through August 2, 2012. An initial ballot was conducted July 24 through August 2, 2012.
  The weighted sector vote for the initial ballot was 54%.
  Responses to the comments received are currently being developed. No timetable has been established for moving to a successive ballot.

- *Project 2013-02: Paragraph 81*
  On October 25, 2012, the requirements being proposed for retirement (38 requirements in 22 standard versions) and an implementation plan were posted for a formal comment period and an initial ballot that will end on Monday, December 10, 2012 (the initial ballot will begin on Friday, November 30, 2012).

- *Project 2007-02 Operating Personnel Communication Protocols*
  Draft 4 of COM-003-1 was posted November 14, 2012 for its second successive 30 day comment period and 10 day concurrent ballot (commencing December 04, 2012) ending December 13, 2012.
  The SDT conducted a webinar on November 27, 2012.

- *Project 2007-06 System Protection Coordination*
  The 2nd drafts of the standard and associated documents were posted for a 30-day formal comment period that began Friday, November 16, 2012 and ends

December 17, 2012. The successive ballot will run from 12/07/2012 through 12/17/2012.
NOTE: The SC agreed the delay associated with the QR and results-based feedback is acceptable, but did not want to reforecast completion. The project will continue to be reported as behind schedule, with the understanding that this is an acceptable delay.

- *Project 2007-12 Frequency Response*
  NERC filed for an extension of time to complete the proposed standard. FERC responded granting an extension of one year (filing deadline - May 31, 2013). NERC held two technical conferences on Frequency Response and collected technical comments and opinions on relevant issues. NERC filed a second progress report at FERC on this standard on October 31, 2012. The SDT has prepared a third draft of the standard and associated documents for posting and a successive ballot. The drafts of the standard and associated documents was posted for a 30-day comment period and successive ballot on October 5, 2012. The comment period and successive ballot ended on November 5, 2012. The proposed standard passed with a quorum of 82.04% and an industry approval of 76.30%. The SDT is responding to comments received. The proposed standard is anticipated to be posted for re-circulation ballot during the week of December 10, 2012.
  This project is being coordinated with Project 2010-14.1 Balancing Authority Reliability-Based Controls-Reserves for the BAL-012 standard.

- *Project 2007-17 Protection System Maintenance and Testing*
  The BOT approved PRC-005-2 at their November board meeting. The initial FERC filing documents were prepared and sent to NERC management and legal staff. NERC legal and standards developer are drafting the petition.
  NERC has initiated the process of gathering data pertinent to reclosing and auxiliary relays that is necessary to develop requirements for the maintenance of those relays. PRC-005 as well as the definition of Protection Systems will be revised over the course of the next few years in accordance with the timetables filed with FERC. Looking more closely at process here, PRC-005-2 progressed through the normal standards development process including four postings (all formal) for stakeholder comment over a 24 month period, beginning with an initial ballot in July 2009, and a failed recirculation ballot in June 2011. The Standards Committee authorized re-initiating the project with a posting of the SAR and revised standard (Draft 1) for a formal comment period and an initial ballot of the standard in August 2011. Draft 4 was posted for comment with a successive ballot in July/August 2012.
  FERC issued Order 758 (February 3, 2012) approving a NERC Interpretation on PRC-005-1 and further directed NERC to include reclosing relays as well as auxiliary and non-electrical sensing relays (including sudden pressure relays).

•NERC believes it is on track to meet all outstanding directives associated with PRC-005, including those emanating from Order 758.
•NERC submitted two informational filings to FERC in response to Order 758.
•NERC drafted a SAR to add the maintenance and testing of reclosing relays in version PRC-005-3 which will begin immediately after PRC-005-2 is BOT approved.
•NERC submitted a schedule to include sudden pressure relays (used in taking transformers out of service) and other auxiliary relays in PRC-005-4 beginning in 2014.

- *Project 2008-06 Cyber Security Order 706*
  The NERC Board of Trustees approved CIP Version 5 on November 26, 2012, and it is being prepared for filing.

- *Project 2009-01 Disturbance and Sabotage Reporting*
  The standard was posted for a 30-day comment period and successive ballot which ended on May 24, 2012. The team met June 6-8 and began to respond to comments and revise the standard. The team conducted stakeholder outreach to help the standard achieve a successful ballot. The team held an industry webinar July 30, 2012 and then a team meeting to finalize all documents for posting and successive ballot. The team submitted the documents for QR on August 3, 2012 and received the results on August 15th. The team responded to the comments received from QR on August 23.
  The standard was posted for successive ballot that ended on September 27th with a 63.40% approval rating. The team met October 4-5 to discuss the comments received and next steps. The team will proceed to recirculation ballot and held an industry webinar on October 22. The recirculation ballot began on October 24th and was extended until November 5th due to issues arising from "Superstorm Sandy". The standard passed the recirculation ballot and was approved by the NERC BOT on November 7th. The Standards Coordinator is working with NERC legal staff to develop the regulatory filing documents.

- *Project 2010-05.1 Phase 1 of Protection Systems: Misoperations*
  The drafting team met November 27-30, 2012 at NERC HQ in Atlanta. The team consulted with the NERC RAPA group and NERC Legal staff and decided to remove the reporting obligation from the standard. Misoperation reporting will be handled with a RoP Section 1600 data request. The team has scheduled to additional Ready Talk meetings on December 11 & 13, 2012 to continue developing responses to comments.
  The standards developer will prepare all the associated documents once the draft standard is completed. The draft standard will be posted for a successive ballot in January 2013.

- *Project 2010-14.1 Balancing Authority Reliability based Controls – Reserves*
  The four draft Standards were posted on June 4, 2012 for a 30 day formal comment period. The SDT has responded to comments received from the posting. The project was delayed due to other higher priority project postings, but is now being expedited to coordinate with Project 2007-12 Frequency Response.
  BAL-012-1 was posted for a 45-day comment period and initial ballot on November 30, 2012.
  BAL-001-1, BAL-002-2 and BAL-013-1 are anticipated to be posted for a 45-day comment period and initial ballot during the week of December 17, 2012.

  On BAL-012 the industry does not seem to support it; opposing need for the standard. Some believe it should be part of the P81. Analysis is needed to verify whether FERC directive is being followed and what options are available.

b. Status of Outstanding Interpretations*

- *Project 2010-INT-03 TOP-002-2a for FMPP*
  Possible candidate for Rapid Revision.

- *Project 2009-19 Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group*
  Project restarted based on BOT Action re: the scope of this interpretation and the team's ability to rely on language other than solely the requirements. New chair Al DiCaprio assigned.
  The interpretation was posted for comment and ballot. The ballot ended on September 4, 2012. The interpretation passed with an 87.78% approval rating.
  The SDT addressed comments received and a recirculation ballot has been posted (September 28 - October 8, 2012). The re-circulation ballot passed with an approval rating of 85.11%.
  The NERC BOT adopted the draft interpretation during their November 2012 meeting.

- *Project 2012-INT-06 CIP-003 for Consumers*
  Consumers Energy requested interpretation of CIP-003-3 regarding the Applicability Section 4.1 and multiple functions, and on Requirement R2 regarding whether a Registered Entity can assign different CIP Senior Managers for different applicable functions for which it is registered. The drafting team posted Draft 1 of the response to the interpretation request for CIP-003 for a 30-day formal comment period, ending December 10, 2012.

- *Project 2012-INT-07 CIP-005 for AEP*

AEP requested clarification on CIP-005 whether for the purposes of access point identification, "externally connected communications endpoints" include those communications links that do not use either (1) a routable protocol (such as IP), or (2) a dial-up modem. The Interpretation Drafting Team is drafting the interpretation for AEP and anticipate posting for an initial comment period in Q1 of 2013.

- *Project 2012-INT-05 CIP-002-3 for OGE*
  Asks for clarification about applicability of CIP-002-3 R1.2.5 to Advanced Meter Infrastructure (AMI) systems (i.e., whether AMI systems must be considered in an entity's risk-based assessment methodology under CIP-002). The interpretation drafting team responded to comments from the first formal comment period, and the interpretation is currently posted for a 45 day formal comment period and parallel initial ballot, ending on December 20, 2012.

- *TBD RFI received on 7/22/11 from EEI and NRECA on CIP-001-1*
  In August the SC voted to move forward with this interpretation. Drafting team appointment on hold pending finalization of CAN-0016 to see if the revision of the CAN provides clarification. In September, the SC reaffirmed this decision. On January 25, 2012, EEI and other trade organizations submitted an appeal of CAN-0016. The results of the appeal were posted to the NERC website on February 8, 2012.

- *Project 2012-INT-04 CIP-007 for ITC*
  Interpretation requests clarification on CIP-007-3, Requirement R5.3. Specifically, the questions relate to the use of "technical and procedural controls" in Requirement R5, and whether each sub-requirement requires both technical and procedural controls. The Interpretation Drafting Team has posted the interpretation for its first formal comment period, ending on December 10, 2012. This request for interpretation is similar to the request for interpretation in Project 2012-INT-03 (TECO), which is on hold pending the outcome of this interpretation.

- *Project 2009-22 Interpretation of COM-002-2 for the IRC*
  The filing for the project 2009-22, COM-002-2a, R2 Interpretation will coincide with the filing of and project 2006-06, COM-002-3 and project 2007-02, COM-003-1. The target for filing will depend on the February 2013 BOT meeting results.
  NERC staff is preparing the filing documents for the February 2013 BOT review and action and for FERC approval in 2013.

- *Project 2012-INT-02 TPL-003-0a & TPL-004-0 for SPCS*
  The interpretation 45-day formal comment period and initial ballot ended December 5. The comment report and ballot results are being prepared for the

Standard Developer. The team will respond to comments received from industry stakeholders via conference call on December 18 and, if needed, on December 20, to work toward its next posting and ballot in early January 2013.

c. Posting Projections through January 2013* (K. Iwanechko)

To be posted during the week of December 10:
- *Project 2007-09 Generator Verification – PRC-024-1 (30-day comment period and successive ballot)*
- *Project 2007-09 Generator Verification – MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-1 (recirculation ballot)*
- *Project 2010-11, TPL FN "b" (30-day comment period and successive ballot)*
- *Project 2010-14.1 BARC: BAL-001-1, BAL-002-2, BAL-013-1 (45-day comment period and initial ballot)*

To be posted during the week of December 17:
- *N/A*

To be posted during the week of December 24:
- *Project 2013-02 P81 (possible recirculation ballot)*

To be posted during the week of December 31:
- *Project 2010-05.1 PRC-004 (30-day comment period and successive ballot)*

To be posted during the week of January 7:
- *SPM Revisions to Implement SPIG Recommendations (possible recirculation ballot)*
- *Project 2010-13.2 Generator Relay Loadability, PRC (45-day comment period and initial ballot)*

To be posted during the week of January 14:
- *Project 2007-02 Operating Personnel Communications Protocols: COM-003-1 (possible recirculation ballot)*

To be posted during the week of January 21:
- *Project 2010-17 DBES Phase 2 (45-day comment period and initial ballot)*
- *Project 2007-06 System Protection Coordination – PRC-027-1 and PRC-001-3 (possible recirculation ballot)*
- *Project 2007-09 Generator Verification – PRC-024-1 (possible recirculation ballot)*
- *Project 2010-11, TPL FN "b" (possible recirculation ballot)*

To be posted during the week of January 28:
- *N/A*

5. Actions

a. Reliability Standards Development Plan* **(Approve)**

The 2013-2015 Reliability Standards Development Plan (RSDP) represents a bold new work plan for standards development, designed to transition from the existing set of NERC Reliability Standards to a clear, concise, and stable body of world-class high-quality reliability standards that ensure the reliability of the bulk power system. At the same time, this plan brings the ERO standards program current with its obligations to address regulatory directives and conduct five-year reviews of all standards, all within the plan's 2013-2015 time horizon. NERC staff, the Standards Process Improvement Group (SPIG) and the Standards Committee (SC) have worked closely to conduct an intense evaluation of the current issues facing standards development. Based on this evaluation, this plan sets forth an approach that will result in a world-class body of Reliability Standards by 2015. Specifically, in 2013, this new approach involves addressing three major areas of work:

- *Existing Projects - Current projects must be completed and new projects that either support high risk reliability issues or emerging issues must be conducted in a timely and efficient manner*
- *Reviews – Five-year reviews must be conducted on standards that are due for assessment and have not been revised in recent standards development projects*
- *Directives - FERC directives must be addressed and the resulting revised standards filed.*

*In a**d**dition, there are two major initiatives will be applied across these three major work areas during their completion:*

- *Paragraph 81 Phase II*
- *Results Based Standards*

These two initiatives will be applied to each standard or group of standards within the three major work areas ensuring requirements that do little to ensure the reliability of the bulk power system are eliminated and all new or revised standards are drafted as Results Based Standards.
The use of these initiatives will lead to a concise set of standards that have the necessary combination of risk-, performance-, and capability-based requirements to ensure the reliability of the bulk power system in North America.
Further, another element to be applied, as appropriate, to the three major areas of work is the use of self-correcting language Information regarding Paragraph 81 can be located on the and/or the concurrent development of compliance information tools as may be proposed through the implementation of the Reliability Assessment Initiative (RAI). Further, close coordination between the standard drafting teams and NERC's Compliance Operations will be part of the overall drafting process.

In addition to developing a world-class body of standards, the standards development process is being revised in response to concerns raised by the NERC Board of Trustees (Board).
Currently the SPIG has recommended, and the SC and its subcommittees have developed, a set of changes which are intended to improve efficiency and the quality of standards. In response to a resolution issued by the Board at the November 2012 meeting calling for additional improvements in four areas, additional changes are being considered.
This document is meant to outline the activities in the development of Reliability Standards during 2013-2015. The work plan has been separated into the three work areas identified above. The areas are not exclusive; thus, although the work has been divided across the work teams, the individual standard drafting teams will continue to coordinate specific standards projects according to the scope of work assigned to the team by the Standards Authorization Request (SAR).

Approved with no objections or abstentions. Minor typographical corrections will be done before submitting to BOT.

b. Project 2010-16 Definition of System Operator – Solicit Nominations (H. Gugel) **(Authorize)**

Request to solicit nominations for SDT members.
Question on priority as there are other more important projects.
Approved with no objections or abstentions.

6. Discussion Items

a. Update on Draft Strategic Plan, Work Plan, and Charter Changes* (M. Lauby, A. Mosher) **(Discuss / Request Comments -** to be sent separately**)**

The following areas of strategic focus are created to produce significant progress in 2013 and 2014 toward a comprehensive set of Reliability Standards that are high quality, technically sound, clear, risk and results-based, and, that also address outstanding regulatory directives while retiring any requirements that provide little protection for bulk power system reliability or may be redundant.

1. ***Transition the current body of standards*** *– Complete the transition to a stable, world-class set of clear, concise results-based standards that ensure the reliability of the bulk power system.*
2. ***FERC Directives and Recommendations from the 2003 Blackout Report*** *– Target a filing to resolve all currently outstanding FERC directives by the end of 2013.*
3. ***Five Year Review of Reliability Standards*** *– Complete any outstanding 5-year reviews of Reliability Standards.*
4. ***Finish remaining open Standard projects*** *– Focus project management on active and inactive Standard development projects to bring closure to*

these projects by the end of 2013. Closure in some instances may involve a recommendation to stop some projects, consolidate projects or roll them into the Directives project. Projects that cannot be completed by end of 2013 will have a specified completion date agreed to by the SC.

5. ***Paragraph 81 and Results-Based Standards concepts*** *– Apply Paragraph 81 (retire or modify FERC-approved Reliability Standard requirements that as FERC noted, "provide little protection to the reliable operations of the BES", are redundant or unnecessary) and Results-Based Standards concepts across the above mentioned major work areas (2-4) during their completion.*
6. ***Existing or Emerging Issues and Reliability Risks*** *– Address emerging risks to the bulk power system by developing high quality and technically sound Reliability Standards, as needed, and in a timely manner.*
7. ***Maintenance of Existing Reliability Standards*** *– Continue to review existing Reliability Standards to ensure the standards remain up-to-date. Provide interpretations on Reliability Standards as required in the Standards Process Manual.*
8. ***Compliance Input*** *– Provide technical expertise and feedback on NERC's compliance program, including Compliance Application Notices (CANs), Compliance Analysis Reports (CARs) and Reliability Standards Audit Worksheets (RSAW), etc.*

The following are the key tactical recommendations. The details related to this Implementation Plan are set forth in the following Implementation Tasks section,

Accountability to BOT

Review and revise, as necessary, the SC charter, processes and procedures to emphasis SC accountability to the BOT for the timely completion of Standard development projects that produce high quality, technically sound, clear, risk and results-based Reliability Standards. These changes shall include enhancing the SC's review of draft and final SARs and the work product of Standard Drafting Teams (SDTs) as consistent with producing high quality, technically sound, clear, risk and results-based Reliability Standards.

Smaller, more agile and committed SDTs

Ensure the SC authorizes smaller, more agile SDTs that consist of no more than ten people, who are suitably equipped to address the objectives of the standard being drafted (i.e., subject matter experts (SMEs), a facilitator, project manager, technical writer and compliance, legal and regulatory experts). Stakeholders can perform more than one of these roles. NERC staff shall assign a NERC staffer as the primary facilitator and project manager to each SDT. In those instances in which the SC also appoints a stakeholder facilitator or project manager, NERC staff and the stakeholder facilitator or project manager shall be co-facilitators or co-project managers. In each case, the NERC staff and/or stakeholder facilitator and project manager shall work closely with the SC project manager and oversight subcommittee, as set forth below.

Each SDT member must commit to have the willingness and ability to devote the time and effort necessary to meet the project schedule. Also, to promote the effectiveness of the smaller SDTs, NERC staff and stakeholder facilitators, technical writers and legal/regulatory experts shall assist SMEs to draft documents during and in between meetings. Further, NERC staff, with the active support of the SC, shall create pools of SMEs (e.g., BAL SMEs, TPL SMEs, CIP SMEs and the like) who will act as technical consultants for the smaller, more agile SDTs as well as the SC. These pools of SMEs shall not be formal members of a SDT, but may be called on from time-to-time by a SDT or SC to assisting in the understanding of technical issues.

Aggressively oversee and manage the workflow and effective use of the Standards development process

The SC shall develop a comprehensive set of high-quality, technically sound, clear, risk and results-based Reliability Standards in a timely manner. To achieve this goal, the SC shall:

- *Implement the following the major work areas through the Reliability Standards Development Plan:*
  - *Address outstanding regulatory reliability directives and recommendations from the 2003 Blackout Report;*
  - *Address NERC's five-year standard review obligation; and*
  - *Prioritization and completion of on-going Standards development projects and any emerging issues.*

Paragraph 81 and Results-Based Standards concepts will be applied across these three major work areas during their completion:

- *Integrate the interaction/processes with the Reliability Issues Steering Committee (RISC) foundational work efforts, including ranking, prioritization, and completion of the standards work.*

- *Engage the Operating Committee (OC), Critical Infrastructure Protection Committee (CIPC) Planning Committee (PC), RISC, and regional committees to develop a process to obtain technical inputs to aid Standards development.*

- *Establish enhanced consensus building, collaborative and communication approaches for the SC and stakeholders to use prior to the approval of a new Standards development project and throughout the Standards development process. Similarly, establish enhanced communication plans for SDTs to provide for greater consensus building and collaboration.*

- *Establish a new SC project management and oversight subcommittee to ensure the timely completion of high quality, technically sounds, clear and results-based Reliability Standards. The new project management and*

oversight subcommittee shall closely work with NERC staff (including NERC staff assigned as facilitators and project managers to each SDT) and the SDTs to develop a project timeline and to ensure each SDT is on schedule and meets its milestones and deadlines. The SC shall also ensure that the smaller SDTs call on, as needed, one or more experts from the applicable pool of SMEs. For example, if a MOD SDT needs to understand how a MOD issue is handled in Electric Reliability Council of Texas (ERCOT), it shall call on the MOD SME with ERCOT expertise to answer any questions and provide guidance.

- *The new SC project management and oversight subcommittee may also request that a SC member act as a liaison with a specific SDT to provide guidance and oversight, and to communicate back to the subcommittee on any concerns or issues.*

- *Address, as necessary, the need to revise training, processes and procedures, such as the Ten Benchmarks of Excellent Reliability Standards, to emphasis results-based requirements.*

- *Collaborate with NERC Compliance staff to provide inputs to the Compliance Monitoring Enforcement Program (CMEP) and compliance elements.*

- *Review the charters of the SC and its subgroups to ensure these documents are properly organized to accomplish the mission described in the SC strategic plan.*

Implementation Tasks

The following is a work plan with specific implementation tasks. Tracking of the responsibility for completing the implementation tasks and associated deadlines are set forth in Appendix A.

***Task No. 1: SC Accountability – Review of the Standards Committee Charter**:*
Implement revisions needed to the SC charter to enhance the SC's accountable to the BOT, including the delivery of high quality and timely Reliability Standards and the execution of the Strategic Plan. All revisions, creation or elimination of SC charter provisions or proposed changes to the Rules of Procedure/SPM shall be presented to the full SC for review and adoption, prior to presenting to the BOT for approval.

***Task No. 2: Review of the Standards Processes and Procedures**:*
Implement revisions needed to NERC's Rules of Procedure/SMP and SC processes and procedures to enhance SC and SDT accountability to timely delivery high quality Reliability Standards and execute the Strategic Plan, including the completion of Standards Process Input Group (SPIG) recommendations. All

revisions, creation or elimination of processes and procedures provisions shall be presented to the full SC for adoption, prior to presenting to the BOT for approval.

Task No. 3: Three Reliability Standard Development Plan Work Areas

The SC and NERC Staff shall work together to develop a work plan for the coordination and deployment of the Standard work areas, applying Paragraph 81 and Results-Based Standards concepts:

- *Address outstanding regulatory reliability directives and recommendations from the 2003 Blackout Report;*
- *Address NERC's five-year standard review obligation; and*
- *Address the completion of on-going and pending Standards development projects and any new projects required to address emerging issues.*

Task No. 4: Interaction with RISC

Integrate the interaction and processes with the RISC foundational work efforts, including ranking, prioritization, and completion of the standards work. Coordination should include the following: (i) receiving technical research or input from NERC standing and technical committees prior to a standard being developed, as necessary, and (ii) a technical review of the draft standards.

Task No. 5: Training and Outreach

Outreach to stakeholders and provide training to SDTs on the revised SC charter processes and procedures related to the Standards project development.

Task No. 6: Review of SC and align the scope of SCPS

The SC will evaluate the following to align their objectives with the strategic plan: (1) the membership of the SC, starting with the 2014 elections; (2) the duties of the Executive Committee of the SC and (3) the SCPS, and (4) the Functional Model Working Group (FMWG). These reviews are to be completed and implemented by June 2013.

Task No. 7: Increased Access to Subject Matter Experts

An increased pool of industry experts are needed who can quickly address pressing Reliability Standards issues. Therefore, the NERC staff, with active support of the SC, shall solicit pools of SMEs to serve as technical advisors for each of the Standard categories.

Task No.8: Increase collaboration

Increase collaboration with the NERC standing committees, Trades, NERC Staff and/or Regional Entity Staff on any emerging or new proposed projects/SARs and decisions to dispense of any projects listed in the Reliability Standards Development Plan.

Task No. 9: Project management and oversight subcommittee

Establish a new SC project management and oversight subcommittee that reports to the full SC and works closely with NERC staff (including NERC staff's facilitators and project managers) and the SDTs. (See Appendix B for organizational chart). This new subcommittee shall have, at a minimum, the following duties:

a. Work closely with NERC staff facilitators, project managers and the SDTs to establish milestones and deadlines for SARs and SDTs and to ensure SDTs are satisfying standard drafting principles;

b. Work with NERC staff to evaluate the completeness of the technical basis for proposed SARs and standard projects and make a recommendation to the SC;

- *Engage NERC's technical experts on the various NERC technical, standing and regional committees.*

c. Oversee the completion of the milestones and deadlines, and extend or expedite milestones and deadlines, as appropriate;

d. Intervene as a special facilitator for any SAR team or SDT that is struggling to reach consensus and/or meet its milestones and deadlines, by ensuring that consensus can be developed and milestones and deadlines met;

- *As part of the project plans, SDTs should review their technical work with the appropriate NERC technical, standing and regional committees for consultation, review, comments and endorsement.*

e. Monitor the productivity of SDTs;

f. Work with NERC staff to develop/refine project management tools for tracking projects and communicating the status or projects;

g. Focus SDT meetings on tasks necessary for production and not on group editing of documents or other tasks that could be accomplished between meetings;

h. NERC Staff or the technical writer or legal and regulatory experts can develop draft documents related to the standards project prior to any meeting;

i. Ensure SDTs use informal methods to consensus building; and

j. Ensure the SDT members are not promoting compliance hedging or mitigation of compliance risk.

Task No. 10: Outstanding Projects (2014-2015)

Complete any outstanding or emerging standard projects. To the extent not already completed and practicable, develop plans to reduce the number of standards, through combining, consolidating and merging existing standards that share the same or similar reliability objectives and principles.

Task No. 11: Coordination with Compliance

Continue to provide support and expertise on the potential impact of issues related to compliance documents (e.g., CANs, CARs, RSAWs) and the movement

away from zero tolerance and towards internal controls, etc. Develop the compliance assessment information in parallel with the review and update of each standard. These tasks shall be completed in conjunction with the Compliance and Enforcement departments of NERC and the Regional Entities.

Task No. 12: SC Communications and Planning Subcommittee to communicate with Stakeholders about Standards Committee activities to facilitate consensus building and stakeholder buy-in.

Task No. 13: Annual review of Strategic Plan and Work plan.

Discussion:
Significant change in the whole standards development approach.
Proposed SC Charter now being reviewed by NERC Legal to ensure all is consistent and covered. Will be sent to SC next week.
Closure (SC approval) expected at January meeting to be then sent to the BOT. Comments to be sent to Howard Gugel by next week cob Dec 20). Another time window for comments by first week of January.

b. Update on Revisions to Outstanding VRFs/VSLs Project and Schedule* (M. Huggins)

NERC standards, legal, and enforcement staff have collaborated with FERC staff to review a set of outstanding VRFs and VSLs for revision or further justification. In general, the VRFs and VSLs require revision in order to reflect the NERC and FERC VRF guidelines and VSL guidelines finalized between 2007 and 2009. FERC staff identified VRFs and VSLs in need of modification or further justification and presented them to NERC staff, offering an opportunity for review and modification before the Commission issues a final order.
As has been the practice with VSL-specific revision projects in the past, the revisions were posted for industry comment and a non-binding poll that ended October 23, 2012. This practice has been adopted for projects such as this one, that are limited to revising VRFs and VSLs, because it provides an opportunity for stakeholder input that is consistent with that for VRFs and VSLs developed in conjunction with a specific standards project.
The modified assignments received 73% approval. NERC staff reviewed all comments and incorporated suggested revisions that added clarity or better conformed to a FERC or NERC guideline. The final revisions and a consideration of comments document have been posted and will be presented to NERC's Board of Trustees during a conference call on December 19, 2012. If adopted, the revisions will be presented to applicable regulatory authorities for approval by February 2013.
This project represents a significant collaborative effort among FERC staff, NERC staff, and industry reviewers to eliminate the need for a formal FERC order with

directives. Rather, a results-based solution was reached through an informal collaborative process.

c. Modification of Glossary Term "Area Control Error" for WECC Regional Variance* (H. Gugel)

In its posting and approval of WECC Regional Variance BAL-001-1, WECC entities approved the following modification to the definition of Area Control Error during their ballot of BAL-001-1:
Area Control Error: The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.
Automatic Time Error Correction: The addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error.
It was necessary to modify the definition to include ATEC; otherwise WECC would have to write a variance for every standard that used ACE. Since the additions affect no other region or Interconnection, it seems appropriate that the modification can be made without a continent wide ballot.
This standard is going to the BOT in December and is necessary for WECC to meet FERC directives. If the SC deems that the glossary terms need a continent-wide ballot, then we must either:
1. Pull the item from the BOT agenda until the terms have been balloted, or
2. Ask the BOT to approve the item but require the standard not be filed with FERC until the Glossary terms undergo a continent-wide ballot.

The definitions above apply only to WECC and were not balloted continent-wide. ERCOT and Eastern interconnection did not vote on it. Question on whether it can go like this to the BOT. It was the SDT that came with idea of developing of these terms applying only to WECC, otherwise a regional variance would be needed for every requirement in the standard. No comments were received relating to the definition.

Approved with 2 abstentions.

d. Subcommittee Reports

1. Communication and Planning Subcommittee (A. Brown)

This committee will have important role in implementation of the strategic plan.

2. Process Subcommittee (B. Li and L. Campbell)

Primary work has been in SPM.
Meeting January 15 in Atlanta prior to SC.

3. Nominating Committee (Fred Plett)

E-mail will be sent to SC shortly. Chair election will be 1-year term to replace Allen.

4. COM-003 ballot

Discussion on next steps in case the industry continues to reject. Postponed because the ballot has not closed yet.

7. Coordination (Review) (S. Tyrewala)

9. Coordination with Regulatory and Governmental Authorities

b. Upcoming Standards Filings*

DATE	PROJECT/DESCRIPTION
November 20, 2012	*Nova Scotia quarterly filing of FERC-approved Reliability Standards*
November 21, 2012	*Project 2011-INT-02* *Petition for Approval of VAR-002-2b – Generator Operation for Maintaining Network Voltage Schedules; Docket No. RD13-2-000*
November 26, 2012	*Comments in Response to the NOPR Proposing to Approve PRC-006-NPCC-01; Docket No. RM12-12-000*
November 29, 2012	*Quarterly filing regarding 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;*

UPCOMING FILING DATES

DATE	PROJECT/DESCRIPTION
December 24,	*DUE DATE: Comments on GMD NOPR*
December 24,	*DUE DATE: Comments on FAC-003-2*
January 31,	*DUE DATE: BAL-003 quarterly report*
January 31,	*DUE DATE: Ballot results quarterly*

CIP standards projected by end of January. NERC sent memo to trades requesting feedback on approach to implementation plans to skip version 4.

8. Informational Items (Review)

9. NERC Drafting Team Vacancies*

b. Standards Committee Roster*

c. Highlights of Parliamentary Procedure*

d. Schedule and Locations for 2013 Meetings*

9. Executive Committee Actions (Pre-authorize)

- *Frequency response (BAL-001, BAL-002 and BAL-013) ready for posting. Not good to wait for January meeting.*

- *Also possible SAR on GMD.*

Both approved. SCEC call TBD on first week of January.

10. Adjourn

NERC Operating Committee

Meeting Notes

December 12 and 13, 2012

NERC Member Representatives Committee / NERC Board of Trustees Meeting-November 6 and 7, 2012 (T. Bowe)

Following the August MRC / BOT meeting which focused largely on the standards process, the November MRC / BOT meeting stressed the future of both compliance and standards. Mr. Cauley reported that two parallel initiatives were being pursued, compliance with a focus on reliability assurance and an enhanced Standards Process. Mr. Bowe also noted that the efforts of the OC were recognized and very much appreciated by the NERC BOT.

Operating Reliability Subcommittee (J. Wise)

Mr. Wise reported that the ORS agreed to accept the recommendation of the IRCWG to retire three documents; this issue was to be addressed as an agenda item later in the meeting. He also noted that, in the coming months, MISO would become the RC for Entergy as well as fourteen smaller BAs. Recognizing the significant change to the MISO footprint, the ORS will present a revised reliability plan to the OC at its March meeting.

Resources Subcommittee (G. Beckerle)

Mr. Beckerle reported that the newly developed draft for a Reliability Guideline addressing ACE Diversity Interchange would be presented to the OC for approval later in the meeting. He also noted that the RS would be updating the Constant Frequency Operations Guideline to provide a tutorial for generator operation during a major bulk power system event.

Event Analysis Subcommittee (H. Hamdar)

Mr. Hamdar reported that the EAS had revised, and posted for industry comment, a revised process document reflecting industry comment and input to the event analysis process. He noted that the final draft will be presented to the OC for approval at its June meeting.

Mr. Hamdar also reported that the EAS was pursuing:

- any identified trends demonstrated by recent cold weather events in North America;
- outreach to the transmission and generation forums; and
- the development of training modules to reinforce and disseminate lessons learned while also providing training CEHs.

Draft Reliability Guideline: ACE Diversity Interchange (G. Beckerle)

Mr. Beckerle advised the OC that, following its approval of a white paper at its March meeting, the white paper had been transitioned into a draft Reliability Guideline by the ORS and posted for public comment. Only one public comment was received and addressed.

The NERC Operating Committee approved the "ACE Diversity Interchange Reliability Guideline" as presented.

Reliability Guideline: Extreme Cold Weather Preparedness (B. Hampton)

Following the addition of an introductory paragraph observing that an extreme cold weather situation can be a HILF event in parts of North America, the OC approved the proposed draft as a Reliability Guideline.

Electric Transmission Performance Improvement Initiatives-Disturbance Investigation System (B. Starling)

Mr. Starling summarized the processes employed by Dominion Power to reverse upward trends in relay misoperations, resulting in a 21% drop in such failures.

Arizona-Southern California Outages on September 8, 2011-Causes and Recommendations

Mr. Ashbaker provided an overview of the actions taken to date by the WECC in response to the recommendations presented in the SW report. The WECC is focusing its efforts in five major areas: NERC, reliability coordination, operations and planning, compliance and the organizational structure of the WECC. He noted that published next day studies are now being shared with all signatories of a universal WECC Non-Disclosure Agreement. A methodology to identify and manage SOLs and IROLs has been developed as well by the WECC.

Following the presentation, the OC discussed the following considerations for further pursuit by the OC in response to the recommendations of the SW report:

Real Time Contingency Analysis

Mr. Bowe asked if every TOP should be required, through a Standard, to have a real time contingency analysis (RTCA) tool and to conduct real time contingency analysis (RTCA) assessments. Mr. Moon stressed that there can be a cost effective and layered oversight provided by the OC absent the imposition of a Standard. Mr. Schwerdt pointed out that situational awareness, tools and training were elements present in both the events of September of 2011 as well as August of 2003. The OC agreed that the significant reliability issue was the ability to provide “defense in depth” as adverse conditions evolve, irrespective of the size of the TOP. The ORS was charged to pursue this issue further.

Real Time Tools Task Force Report

The Real Time Tools Task Force Report will be revisited by the NERC ORS with participation by the NATF.

PMU Technology

The OC agreed that mandating a particular technology would be a dangerous approach by the Committee. Other mechanisms, in addition to PMUs, are in place to avoid entering into a state in which angular separations prevent the reclosing of facilities. Mr. Wise reported that the ORS is already reaching out to the NASPI in the development of PMU technology which can be reliably integrated into the control room.

BA Reliability-Based Control Drafting Team

A status of the drafting team to date was provided. It was noted that BAL-001 retains CPS1 but retires CPS2. The DCS will be reported and evaluated per the event. Two new Standards will be proposed, BAL 12 and 13. BAL-013, Large Load, and BAL-002, use 500 MW as a compromise across all Interconnections in response to FERC Order 693 to identify frequency excursions. Following discussion, the OC did not achieve consensus in support of the arbitrary use of 500 MW as the threshold for reporting and could not support its inclusion in the Standard.

The OC was asked if a final report summarizing the ongoing field trial associated with the draft Standard was desired. It was pointed out by the OC that the current field trial represents the longest such effort having been conducted by the OC, and it accordingly agreed that a final summary report was warranted. It was further noted that there were valuable lessons to be learned from the current trial, and it also provided a potential template for future field trials.

The OC will also suggest to the Standards Committee that, should the work on the draft Standard be abandoned, the OC should have input in the unwinding of the field trial.

IVGTF Follow-Up

The OC agreed to accept the report and further direct the report to the OCEC for analysis and return to the OC in March.

Prepared by:

John G. Mosier, Jr.
December 13, 2012

From:	Brian Hogue
To:	grpStaff
Subject:	CIPC notes
Date:	Saturday, December 15, 2012 7:16:20 PM
Attachments:	notes.docx

Notes are attached. Red text is more important.

HIGHLIGHTS

1 - Executive Order on cyber-security

This started in late July / early August with the proposed Lieberman - Collins legislation. Seven Republicans, led by McCain, proposed alternative legislation. Both did not move forward. The next step was October's Presidential Directive which was aimed at US Government networks. The most recent step is the draft Executive Order that was discussed at CIPC. See my notes for what went down during the CIPC discussion plus my personal conversation with the presenter and Janet Sena.

Here is the draft EO -- http://www.us-nesco.org/files/2012/12/White-House-Draft-Executive-Order-Dated-11-21-12-1.pdf

Some preliminary comments on the EO since there several references (not links) to other US documents that must be read for a complete understanding. The EO is aimed at the US government getting its house in order (being consistent with cyber security for critical infrastructures). It appears that DHS will be the lead agency on this project. The EO is silent on what happens with existing regulations that are not under DHS purview. The EO opens the door to new legislation but prefers “inducements” for private sector participation.

Stay tuned -- more to follow

2 - CIP version 5

Almost no discussion on the issue of 3 - skip 4 - 5. Prior to CIPC, NERC sent a draft letter to the Trade Association asking which option was preferred. Transmission Forum met earlier in the week and support option #2. From CIPC, it sounds like NERC will propose more than option to NERC. As it stands now, Entities know that version 4 becomes mandatory on April 1, 2014. NERC expects to file version 5 with FERC in January. Version 5's implementation plan calls for 8 quarters between the regulator's approval and that initial mandatory date. However, the industry / BOT approved implementation plan says that if the regulator approves version 5 prior to version 4's initial date, then version 4 does not go into effect -- putting some Entities into an awkward position. Version 4 is the first CIP Standard that uses a series of Bright Lines instead of the Entity's Risk-Based Methodology. If an Entity's asset is identified in those Bright Lines then all of version 4 applies to that asset. Version 5 includes many more assets but version 5 compensates by introducing the BES Impact concept. High BES Impact assets must comply with all of version 5. Low BES Impact assets must comply with a small number of version 5 Requirements. Medium BES Impact assets are somewhere in the middle. Versions 4 and 5 Bright LInes identify Blackstart and Cranking Paths. However version 5 classifies them as Low BES Impact. Versions 4 and 5 Bright Lines identify Transmission/Generation assets. However version 5 classifies most of these as Medium BES Impact. Both situations set the probable scenarios that Entities invest in becoming version 4 compliant and

a few months later would like to re-claim some of that investment when version 5 starts. However these investments are not recoverable expenses.

Gerry Cauley called version 5 a sustainable product -- iow, there are no current plans for version 6

3 - Information Sharing

A few presentations emphasized the need for information sharing in the industry and with government intelligence. No speaker noted the disconnect between that Information Sharing desire and the CIP Standards requirements for Information Protection. For those that do not know, Information Protection is a cornerstone of good security practice. In several presentations, the audience requested actionable information from government intelligence. Compared to a few years ago, the US government better at providing useful information.

While Gerry Cauley called for more industry folks to have US clearance, DHS has not re-opened that process. Matt Blizard (NERC's head of CIP) called for each Entity to have three staff with US clearance, including one "C" level executive.

4 - Turning Point / DHS Uncleared Briefing

Gerry Cauley said 2012 was a turning point for cyber-security which started the year as "might happen" and ends the year as "happened". Jerry/Ralph/Jim/Paul - see #6 in my notes (DHS Uncleared Briefing). Phil these notes reference ONG several times so you might be interested. Frantz/Javier -- there may so useful items for IT.

5 - Compliance Enforcement Input WG (CEIWG)

Interesting to note was the CAR-005 discussion during this presentation. CEIWG strongly did not like CAR-005. Kevin Perry defended it and claimed partial authorship. Rest of room disagreed with Kevin's interpretations and explanations.

6 - Situational Awareness

Very interesting and short presentation by FERC staff - Dave Norton. Suggested that everyone in the room get involved in the NAESB SynchroPhasor project since it will be Situational Awareness. When I asked what that means to SAFNR, Dave was not familiar with SAFNR. Scott Mix (NERC staff) and I had a brief conversation outside. Scott said they are serving two different goals. SynchroPhasor will allow a much deeper drill down for the operator. I told Scott that I would follow up later. Jerry/Ralph - you may want to follow up. Walter - I probably need to understand this product better. Interestingly Bob Cummings used this tool to determine the Southwest sequence of events in less than a week which is a lot better than the industry took determining the 2003

sequence of events.

-brian

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Critical Infrastructure Protection Committee

December 12, 2012 | 1:00–5:00 p.m. (EST)
December 13, 2012 | 8:00 a.m.–Noon (EST)

Westin Buckhead Atlanta Hotel
3391 Peachtree Rd N.E.
Atlanta, GA 30326

Department of Homeland Security Classified Briefing
December 12, 2012 | 7:30 a.m.–Noon (EST)
FBI, Atlanta Office
2635 Century Parkway N.E.
Atlanta, GA 30345

Welcome and Introductions – CIPC Chair Chuck Abell
NERC Antitrust Compliance Guidelines and Public Meeting Announcement*
Agenda

1. Administrative – CIPC Secretary, Bob Canada
   a. Arrangements – Emergency Precautions and Convenience
   b. Announcement of Quorum of Voting Members
   c. CIPC Membership
   d. CIPC Roster
   e. CIPC Charter
   f. Parliamentary Procedures – In the absence of specific provisions in this manual, all committee meetings shall be conducted in accordance with the most recent edition of Robert's Rules of Order in all cases to which they are applicable.
2. Consent Agenda – Chair Abell
   a. Draft CIPC Minutes for September 18-19, 2012
   g. Committee Membership Appointments and Changes:

TRE	Jim Brenton	ERCOT	Cyber
TRE	David Grubbs	City of Garland	Operations
TRE	Vacant		Physical
FRCC	Paul McClay	TECO	Cyber
FRCC	Carter Manucy	Fla Municipal	Physical
FRCC	Darren Myers	Progress	Operations
MRO	Marc Child	Great River	Cyber
MRO	Paul Crist	LES	Physical
MRO	Rick Liljegren	MN Power	Operations
NPCC	Mike Puscas	NU	Operations
NPCC	Greg Goodrich	NYISO	Cyber
NPCC	Benoit Tardif	HQ	Physical
RFC	Larry Bugh	RFC	Cyber
RFC	Kent Kujala	Detroit	Operations
RFC	Jeff Fuller	DPL	Physical
SERC	Chuck Abell	Ameren	Cyber
SERC	Carl Eng	Dominion	Operations
SERC	Tommy Clark	SMEPA	Physical
SPP	John Breckenridge	KCPL	Physical
SPP	Allen Klassen	Westar	Operations
SPP	Robert McClanahan	AECC	Cyber
WECC	Scott Bordenkircher	APS	Physical

WECC	Vacant		Cyber
WECC	Jamey Sample	PGE	Operations
APPA	David Godfrey	TMPA	Physical
APPA	Nathan Mitchell	APPA	Policy
CEA	Chris McColm	Manitoba	Physical
CEA	Ross Johnson	Capital Power	Physical
NRECA	Robert Richhart	Hoosier	Policy
NRECA	David Revill	Georgia Trans	Policy

3. Remarks by NERC's President and CEO – Gerry Cauley

Last half of 2012 transitioned from "might happen" to "happened"
Janice Case a NERC BOD member attending, in case audience has questions of the BOD
Information Sharing improving, becoming more actionable.
Everyone should have awareness.
Clearances are a cornerstone of NERC strategies - needs to include executives.
CIP version 5 is a sustainable product
moving to risk management (away from zero tolerance) is important
If FERC would approve 5 immediately, we would 1.5 years to prepare

4. Chair's Remarks – Chair Abell

DHS sponsored secured briefing
Gerry Cauley
Janice Case
Samara Moore – Executive Order presentation
John Allen – physical security presentation
Update on RISC
Subcommittee / TF / WG reports
GridEx 2013 + GridSecCon 2013 + more
NERC BOT
Approved version 5
Approved 3 new CIPC Members
Approved several Standards including EOP-004-2
New BOT Chair

a. Reports

i. SCCG Meeting October 3, 2012

ii. ESCC Meeting November 27, 2012 + September 27, 2012
3 of 4 TFs completed work
9 new TF & WG chartered and active in '12
Some groups have 20-30 volunteers
Over 150 volunteers engaged

iii. BOT Meeting November 7, 2012

b. CIPC 2012 Work Plan Status & Goals – Strategic Plan posted: **2012 Strategic Plan**
Remaining CIPC 2012 targets
Develop benchmark recommendations for BES Security metrics
Develop recommendations to CIPC / ESCC on security clearances
Improve information sharing

5. **Executive Order for Critical Infrastructure Cybersecurity** – Samara Moore, National Security Staff, Cybersecurity

Reaching to various Sectors – seeking feedback on the draft (which was not presented) before finalizing the draft
Administration supports information sharing
Risk based framework
For Sectors with Standards, administration desires to avoid duplicative requirements
David Dunn (IESO) – what about safe harbor related to other countries (Canada)? Normally, I have to remind CIPC that NERC's footprint includes Canada. Thanks to David's comment I did not need to.
? (?) require government sharing with industry?
Stacy Bresler (NESCO) need to include smaller, non-BES Entities – like a knowledge base?
John Breckenridge (SPP?) – should consider a later presentation which shows the multiple sources of information. Is a one-stop shop possible?
Samara – does this group have any suggestions on how to deal with a cyber-attack?
Tim Roxey (ISAC) – as earlier person said, government needs to provide actionable information quickly
Kevin Perry (SPP) – believe that 1) more clearances is not the answer 2) government needs to provide actionable information via unclassified means
DURING BREAK several people spoke with Samara
I pointed out that the electric grid was not designed with national boundaries in mind – that NPCC covers NY, New England, Ontario, Quebec and the Maritimes, New Brunswick and Nova Scotia. I requested consistency with Canada since the Northeast depends on the inexpensive hydro power from Canada. Janet Serna, NERC BOT member, was hovering and mentioned that there are other Regions that include Canada. I offered that NPCC, MRO and WECC are those Regions with WECC also covering northern Mexico. Next I offered the situation with a dam that his half owned by NYPA and the other half by HQ. Protecting only half the dam is no protection at all. Since Samara's and Janet's heads were nodding a silent YES, I stopped.
Kevin Perry (SPP) introduced himself. Before I could leave, Kevin stated that he is a CIP auditor and that he does not audit to the Standards but to what the Entities should be doing.

6. Cybersecurity Discussion/DHS Unclassified Briefing **–** Eric Cornelius, Chief Technical Analyst and Mark Plemmons, ICS-CERT Analyst

Talking with Brian Malfant (FRCC) about ITSG and returned to meeting
This is the uncleared briefing. Those with cleared briefings heard 3 hours this morning.
Using Shodan to find ICS (Industrial Control Systems)
82 targeted intrusions
US Critical Infrastructure Incident Timeline – various inputs
Cyber attacks on pipelines (December 2011 – June 2012)
    Exfiltrated data could provide ability to access US ONG (Oil-Natural Gas) ICS
    What was taken? (list)
Telvent intrusion
    Customer files impacted in cyber attack of IT company – Telvent Canada
    Intrusion into major ICS vendor
        Could happen at ANY vendor

- Immediately alerted customers (COMMENT – good move)
- SCADA files reportedly exfiltrated
- ICS-CERT concerns
  - Zero day development
  - Supply chain integrity
- What's been done
  - Deployed an isolated, live CD based support environment
  - Introduced 2 factor authentication for remote customer support
  - Reviewing code updates for last 3 years
  - Developed an integrity check tool

Supply chain and Vendor Best Practices

- Trust but verify
- Understand trust relationships with suppliers / vendors
- Build cyber-security into procurement contracts

Shamoon attack on Aramco

- Saudi Aramco based in Saudi Arabia but has US offices
- Business PCs affected
- Aramco maintains their oil production was not impacted
- Highly destructive -> renders infected system useless after stealing information
- Possible that variants are not detected by major AV (Anti-Virus) vendors

RasGas Networks impacted by Shamoon

- Similar impact to Aramco
  - Not detected by AV
  - Payload change
  - Highly targeted
- Email servers and website services disrupted

Destructive Malware Mitigations

- ICS-CERT / US-CERT recommending preventative / mitigating strategies
  - Have a reconstitution plan and EXERCISE it!
  - Transfer critical files to network shares where they can be backed up centrally
  - Execute daily backups of all critical systems
  - Execute an 'offline' backup of critical files to removable media
  - Establish emergency communications plans should network resources become unavailable
  - Isolate any critical networks from business systems
  - Identify critical systems and evaluate the need for having on-hand spares to quickly restore service
- Deploy all available detection capabilities
- Additional recommendations are available at
  - ISC-CERT web site – JSAR-12-241-018 – Shamoon-DistTrack Malware

DDoS Attacks against Financial Sector

- Targeted public facing websites
- Limited by some impact
- More interesting DDoS targets

- Energy markets (electricity / gas)
- Medical records service providers

ICS exploitation tools
- Metasploit has over 50 ICS related exploits
- GLEG Agora SCADA+ Exploit pack is a collection that specifically targets ICS
  - 128 exploits
  - 94 suspected control systems

20,000 internet connected ICS. Map shows high concentrations in
- NYC to Boston (east coast)
- South Florida (Atlantic and Gulf coasts)
- South California (west coast)
- Central California (west coast)

ICS Vulnerability trends (increasing quickly)
- 2009 – 10
- 2010 – 40
- 2011 – 145

Sophisticate attack shopping list
- Knowledge of systems
  - Sensitive ONG pipeline documents stolen
  - Telvent internal files taken in intrusion

Targeted cyber attack defenses
- Develop / maintain incident response plan
- Exercise your incident response plan
- Preserve forensic data and limit intruder's movement through network
- Protect network host login credentials
- Increase logging capabilities to detect exfiltrated data
- Add host-level DNS
- Etc

Zero day defenses (hard not impossible)
- Patch management
- Configuration management

7. Remarks – Matt Blizard, Director of Critical Infrastructure Protection

CIP strategic thoughts
- Address motivational component behind most recent cyber attacks
- Create deterrence for attackers
- Consider separate critical infrastructure network – separate from internet
- Increase information sharing
- Entities and local DOD working together
- Develop next generation of BPS security professionals
- Prepare for / address such significant catastrophes (National Security)

CIP Tactical Actions
- Develop / Enact force multipliers
- Sign-up / use ES-ISAC
- Ensure Entity security officers have direct contact w/CEOs

- Improve forensic capability
- Adopt a best practice of assess – exercise – assess
- Conduct 3rd party penetration testing
- Use industry / NERC / USG Cyber-security Capability Maturity Model

Where do we want to be (2013 – 2016)?

- USG w/industry – cyber doctrine (defense, deterrence, resilience) enacted
- CIP v5 Standards and Compliance – fully implemented w/ strategic effects
- CID value outcomes fully matured
- CIPC – address big problems with expanded base!
- Culture of Security – ensuring reliability
    - Mature ES-ISAC
    - Information sharing & analysis flowing both ways in real time
    - CEO – CSO – NERC ES-ISAC network – fully and strongly connected
    - Partnerships – actively pursued and nurtured
    - Internal controls
    - Embracing technology
    - Assess – exercise – assess
    - Grooming the work force
    - Outreach & learning
    - Resilience preparations

8. Legislative Update – Nathan Mitchell, American Public Power Association (APPA)

Outside of Executive Order

Capitol Hill focused on the fiscal cliff issue

Maybe something next year – many want to tee this up

9. Reliability Issues Steering Committee Update – Jim Brenton, Reliability Issues Steering Committee (RISC) member from CIPC

Mission & purpose

RISC and other committees

RISC

- Advisory committee
- Clearly defined and limited scope
- Membership includes reps from all other committees

Measure of Success

Tools and Nomination Form

10. Sabotage & Disturbance Reporting (Draft 6 of EOP-004-2) – Recirculation Ballot Results, Bob Canada

11. Subcommittee Chairs, Subgroups, Progress, and Remarks – Chair Abell

12. Operating Security Subcommittee – Chair Carl Eng

HILF pretty much completed its tasks

- chair working for a new company
- had 55 Recommendations, 5 belonged to CIPC
- HILF TF retired by unanimous vote

Grid Exercise TF chaired by Tim Conway of NIPSCO

- Charter approved – COMMENT Greg and I do not recall seeing this charter

5 contractors bidding

Electric Sector Information Sharing TF – Chair, Stephen Diebold - **ESISTF Charter**

Overview of Activities

Held 9 teleconferences

Statement of need

Objectives 1-2-3-4

Deliverables

Report status

Homework

Bob Canada (NERC) asked how to handle the statutory 417 with the optional ISAC reporting?

Tim Roxey (ISAC) responded that one could enter the information once on the ES-ISAC but send one copy to the ISAC and send another copy to DOE (for 417)

Jamie Sample (PGE?) said the metrics WG has trouble because there are multiple repositories of events

John Breckenridge (SPP?) supports one stop shopping for submitting events

More comments supporting enter once – distribute to many

HILF Implementation TF – Work Completed & Retiring the TF - **HILF TF Charter**

Grid Exercise WG – Chair Tim Conway - **Draft GEWG Charter**

Posted for CIPC Approval and 2013 Deliverable

13. Policy Subcommittee, Chair Nathan Mitchell

BES Security Metrics WG – James Sample, Chair - **BESSMWG Charter**

- Goal is develop a framework for physical / cyber security metrics that measured and trends the historic performance of controls that safeguard the reliability and resiliency of the BES and identify, monitor and trend leading indicators that could compromise …
- Re-use existing measurement channels
  - EA Reporting
  - DOE 417
  - ALR Reporting
  - ES-ISAC
- Analyzed EA and ALR DBs for security-related events
  - Mostly copper thefts and vandalism
  - Not enough data for conclusions
- Forward (details)
  - ES-ISAC – Ben Miller
  - 417 – Ken Friedman / Brian Copeland / David Scott
  - ALR / EA – TBD
  - Need commitment from NERC / DOE for continued participation

Personnel Security Clearance TF – Chair Jim Brenton - **PSCTF Charter**

- Purpose – coordinate with DHS to determine / recommend appropriate US Government Security Clearance …
- Considered
  - Existing protocols

- Found ongoing need for industry access to actionable information
- Preparing recommendations to CIPC /ESCC on clearances
- Updated model for industry to determine which personnel should seek clearance

- Draft recommendations
  - Entities coordinate with NERC CID to "nominate" individuals for clearance
  - Normally 3 staff for each Entity
  - Including "C" level participation
  - Coordinate exceptions through NERC CID

Compliance & Enforcement Input WG – Chair Paul Crist - **CEIWG Charter**

- 31 participants
- Reviewed CAR CIP-005
- Next meeting is Dec 20
- Topics
  - Charter approval
  - Voting structure
- Key concerns with CAR CIP-005
  - CIP-005-3 R1.1 creating a complex challenge
  - EAP is not defined in versions 1 - 4 (v5 does as routable)
  - CIP-005 R2-R4 implies routable connectivity
  - Inconsistency in the CAR examples
  - EAP not a CCA
  - Auditors referencing CAR
  - Technical difficulties in applying the approach in the CAR
- Next steps
  - monitor 2012-INT-07 CIP-005 for AEP
  - investigate options for requesting definition of EAP based on v5 definition
  - work with NERC on clarifying the CAR
  - other?
- Room disagreed with Kevin Perry who wrote the core of this CAR
- Nathan Mitchell sought representation from each Region on this WG

14. Cyber Security Subcommittee – Chair Marc Child

Control System Security WG – Chair Mark Engels - **CSSWG Charter**

Cyber Attack Tree TF – Chair Mark Engels - **CATTF Charter**

Cyber Security Analysis WG – Chair Eric Warakomski - **CSAWG Charter**

- Returned from checking out of room

Cyber Security Training WG – Chair William Whitney III

Draft Cyber Security Training Charter

Posted for CIPC Approval and 2013 Deliverable

- Next steps
  - Request more members – goal is at least 10 members
  - Assign VC
  - Obtain CIPC approval - unanimous

15. Physical Security Subcommittee – Chair David Grubbs

Electricity Sector Physical Response Guideline TF – Chair John Breckenridge

Draft ESPSRTF Charter

Posted for CIPC Approval and 2013 Deliverable

- Unanimous approval
- Quick moving refresh of existing Guideline (2Q2013)
- Looking for more participation – especially Canadian

Physical Security Analysis WG – Chair Ross Johnson - **PSAWG Charter**

16. 2012 Grid Security Conference and CIP Programs – Brian Harrell, Associate Director of Critical Infrastructure Protection Programs

Common theme will be free training starting GridSecCon

October 15 – 16 – 17 likely Orlando / Tampa or Boston

GridEx II

November 13 – 14

TF will work on this

17. ES-ISAC Update – Tim Roxey, Chief Cyber Security Officer

a. Cyber Brief & Recruitment

41% of Entities on ISAC

Most Entities have 1 user on ISAC

b. Portal update

Recent ES-ISAC Products

2 NERC Alerts

1 ES-ISAC IOC Notice

1 ES-ISAC Trends Report

Up to 80% of attacks start with phishing

c. Alert(s)

18. International Initiative to Address Metal Theft – John Allen, Director, IEIA Forum

Another name for "copper theft"

Participating countries – Australia, Canada, New Zealand, United Kingdom, US

Forum initiatives

Metal Thefts – John Breckingridge (US – KCPL)

Smart Grid – Doug Mader (US – Entergy)

Severe Events – Dion Mikklesen (AU – Powerlink)

Advanced Persistent Threats – Ben Blakely (CA – IESO)

Collaboration Framework

Explore possible collaboration with CIPC

Identify possible initiatives between IEIA Forum and NERC CIPC

Align / exchange IEIA and CIPC resources and information

Proposed metal thefts WG Collaboration

Metal thefts would be initial focus

2 identified priorities (reports)

Statistics and analysis

Metal thefts impact

Next annual meeting – May 1-3, 2013 in Vancouver co-hosted by Public Safety Canada

19. Compliance Operations – Earl Shockley, Senior Director of the Compliance Operations Department

a. Status on the Reliability Assurance Initiative – Reframing of Audits and the CMEP (Internal Controls)

20. Cyber Security Standards Update – Scott Mix and Steve Noess, NERC Staff

a. Version 4 Order & Implementation Dates

What about skipping version 4 and go from v3 to v5?

v4 starts April 1, 2014

no reason why a v3 RBAM could not arrive at the same place as v4 Bright Lines

b. Version 5 Ballot Status and Steps Forward

BOT approval on November 26, 2012

Filing in January 2013

During implementation

- Webinars / conferences
- Venues to collaborate for ensuring strong programs + assessment consistency

c. Interpretation Team

Project 2009-26 approved by FERC

Current

- 2012-INT-05
- 2012-INT-04
- 2012-INT-06

Next – 2012-INT-07 (discussed earlier)

d. Sufficiency Review Program (SRP) for 2012 & 2013

e. Outreach Programs

Version 3 RBAM review

v3-v4-v5 transition issues

Aurora overview

ES-ISAC overview

Technology discussions

Key lessons

- RBAM documentation
  - Definitions
  - Assumptions
  - Reviewed RBAM and supporting documentation should be self-contained
  - Describe CCA criteria
  - Flowchart
  - Discussion of misuse
    - BES facilities
    - CCA
- Results document
  - Spreadsheet format
  - Document “largest” non-triggering element
  - Monitor changing landscape
    - IROL in WECC

BES Definition
CCA evaluation
Tie CA and CCA together
Complete inventory of Cyber Assets inside ESP, EACMS, PACS
Functional description
Spreadsheet
Positive affirmation for all considered criteria
Three approval signatures
Make the change history useful
Discussion of removed assets
2013 Program
Focus more on CCA identification
Continue other 2012 discussions
Looking for additional topics
Anticipate 10 sessions for 2013
5 visits already scheduled
Still looking for volunteers

21. Agency Updates

a. Federal Energy Regulatory Commission – Mr. David Norton
Office of Electric Reliability – we'll tell you when they tell us <audience laughs>
NAESB SynchroPhasor - influence it now since this is what Situational Awareness is evolving into.
I asked what is happening to SAFNR? Dave was not familiar with SAFNR
b. Department of Homeland Security – Mrs. Cathy Eade
c. Department of Energy – Mr. Matt Light – presented by ?
i. Risk Management Process (RMP)
ii. Capability Maturity Model (CMM)
Expects Executive Order to be signed shortly
Sandia Labs immediately before next CIPC?

22. CIPC Meeting Schedule for 2013:

2013 Meeting Dates	Time	Type	Location	Hotel
March 5	7:30am– Noon (MT)	CIPC Physical Security Workshop	Albuquerque, NM	Hyatt Regency Albuquerque
March 5	1:00– 5:00pm (MT)	CIPC Meeting	Albuquerque, NM	Hyatt Regency Albuquerque
March 6	8:00am– Noon (MT)	CIPC Meeting	Albuquerque, NM	Hyatt Regency Albuquerque
June 11	7:30am–Noon (EST)	CIPC Cyber Security Workshop	Atlanta, GA	NERC Offices Atlanta
June 11	1:00– 5:00pm (EST)	CIPC Meeting	Atlanta, GA	Westin Buckhead Atlanta
June 12	8:00am–Noon (EST)	CIPC Meeting	Atlanta, GA	Westin Buckhead Atlanta
September 17	7:30am–Noon (MT)	CIPC Physical Security Workshop	Denver, CO	Hyatt Denver Tech Center

September 17	**1:00– 5:00pm (MT)**	**CIPC Meeting**	**Denver, CO**	**Hyatt Denver Tech Center**
September 18	**8:00am– Noon (MT)**	**CIPC Meeting**	**Denver, CO**	**Hyatt Denver Tech Center**
December 10	**7:30am–Noon (EST)**	**DHS Classified Briefing**	**Atlanta, GA**	**TBD**
December 10	**1:00– 5:00pm (EST)**	**CIPC Meeting**	**Atlanta, GA**	**Westin Buckhead Atlanta**
December 11	**8:00am–Noon (EST)**	**CIPC Meeting**	**Atlanta, GA**	**Westin Buckhead Atlanta**

Closing Items

23. Follow-up Items and Future Actions – Chair Chuck Abell (Action/Discussion)

24. Meeting Adjournment

From: Kimberly Mielcarek
To: Kimberly Mielcarek
Subject: NERC Announcement - NERC Names New Chief Operating Officer, Vice President for Reliability Assessment and Performance Analysis
Date: Thursday, January 03, 2013 10:20:59 AM

Announcement

NERC Names New Chief Operating Officer, Vice President for Reliability Assessment and Performance Analysis

Click here for announcement

ATLANTA – The North American Electric Reliability Corporation (NERC) is pleased to announce that **Mark Rossi** joins NERC as senior vice president and chief operating officer today, and **Tom Burgess** joins NERC as vice president and director of Reliability Assessment and Performance Analysis on January 16.

As chief operating officer, **Rossi** will provide strategic vision, planning, leadership, and oversight of NERC's reliability performance groups, including Standards, Compliance Operations, Reliability Risk Management, Reliability Assessment and Performance Analysis, and Critical Infrastructure.

Burgess will oversee NERC's Reliability Assessment and Performance Analysis group, which conducts periodic, independent assessments of the reliability and adequacy of the North American bulk power system. In addition, the department identifies and tracks key reliability measurements, conducts analysis of risk trends and works with industry on strategic and tactical approaches to address existing and emerging risks to bulk power system reliability.

For more information or assistance, please contact Kimberly Mielcarek

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Announcement

NERC Names New Chief Operating Officer, Vice President for Reliability Assessment and Performance Analysis

January 3, 2012

ATLANTA – The North American Electric Reliability Corporation (NERC) is pleased to announce that Mark Rossi joins NERC as senior vice president and chief operating officer today, and Tom Burgess joins NERC as vice president and director of Reliability Assessment and Performance Analysis on January 16.

As chief operating officer, Rossi will provide strategic vision, planning, leadership, and oversight of NERC's reliability performance groups, including Standards, Compliance Operations, Reliability Risk Management, Reliability Assessment and Performance Analysis, and Critical Infrastructure.

"Mark brings a unique blend of vision, leadership and consensus-building to NERC that will be a tremendous asset to the electric reliability organization," said Gerry Cauley, president and chief executive officer at NERC. "His industry knowledge will be invaluable in fulfilling our mission of ensuring the reliability of the bulk power system."

Burgess will oversee NERC's Reliability Assessment and Performance Analysis group, which conducts periodic, independent assessments of the reliability and adequacy of the North American bulk power system. In addition, the department identifies and tracks key reliability measurements, conducts analysis of risk trends and works with industry on strategic and tactical approaches to address existing and emerging risks to bulk power system reliability.

"Tom has worked in the energy industry for more than 40 years, participating in many NERC efforts, including serving on the Member Representatives Committee and as a former chair of the NERC Planning Committee. His knowledge of the energy industry, as well as NERC, brings an experienced leader to one of our most significant efforts," Cauley said. "Tom is a known and trusted adviser to NERC and I look forward to him joining our management team."

CONTACT:
Kimberly.Mielcarek@nerc.net

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Prior to joining NERC, Rossi served as a partner in Accenture's Global Utilities Practice, providing strategic consulting, technology solutions and outsourcing services to Fortune 500 companies. Previously, he was executive vice president at Gestalt, LLC, where he led the company's Energy and Utility practice, and also managed Gestalt's merger with Accenture. During his career, Rossi has led teams that worked on a number of key electric industry issues, including transmission planning and expansion policy, cost allocation, and market design, working with a number of different industry participants and stakeholder processes.

"I am honored to join NERC's talented team and look forward to working with industry stakeholders in our common mission to ensure the reliability of the bulk power system," Rossi said. "The organization is at a key transition point in its history and has identified several strategic initiatives to move towards a risk-based approach to ensuring reliability. I look forward to working with industry to move these efforts ahead so they deliver the potential value they have for improving reliability."

Most recently, Burgess worked at FirstEnergy Corporation, serving as Executive Director, Integrated System Planning and Development. He was responsible for developing strategic plans that maximize value for the transmission and generation business segment, as well as developing integrated planning strategies that optimize transmission and generation. Prior to joining FirstEnergy, he worked for the Ohio Edison Company and the Pennsylvania Power Company, serving in numerous engineering, planning, regulatory and transmission policy positions.

"This is a tremendous opportunity to help lead and shape the future direction of NERC's reliability assessment and performance program," Burgess said. "I am excited about the opportunity to lead such a talented team, both at NERC and across North America."

###

The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO), certified by the Federal Energy Regulatory Commission in the United States to establish and enforce reliability standards for the bulk power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com.

From:	Guy V. Zito
To:	rsc
Subject:	FW: NERC Standards Announcement | Reliability Standards Communications in Operations - Project 2007-02 Operating Personnel Communications Protocols
Date:	Wednesday, January 16, 2013 3:00:38 PM

FYI

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: NERC Standards Announcements (Do Not Reply) [NERC-StandardsAnnouncements-DoNotReply@nerc.net]
Sent: Wednesday, January 16, 2013 1:57 PM
To: Suzanne Smith-Wigfall
Subject: NERC Standards Announcement | Reliability Standards Communications in Operations - Project 2007-02 Operating Personnel Communications Protocols

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Standards Announcement

Reliability Standards – Communications in Operations Conference

Project 2007-02 Operating Personnel Communications Protocols

February 14, 2013 | 1:00-5:00 p.m. Eastern
February 15, 2013 | 8:00 a.m.-Noon Eastern

Click here for: Meeting Details
Click here for: Meeting Registration
Click here for: ReadyTalk Registration - February 14
Click here for: ReadyTalk Registration - February 15

Background: The goal of this workshop is to develop consensus concerning a North American Electric Reliability Corporation (NERC) Reliability Standard addressing normal communications, as called for in outstanding Federal Energy Regulatory Commission (FERC) directives in Order 693 to NERC. However, there remains outstanding and differing perspectives on the **necessary scope of communication standards**, which must be further discussed and resolved.

The industry continually strives toward improving communications and has

made proposed standard modifications to further improve industry communications. Based on industry experience, effective communication is critical for real-time operations. Failure to successfully communicate clearly can create misunderstandings resulting in improper operations increasing the potential for impacts on Bulk Electric System reliability.

The Operating Personnel Communications Protocols Standard Drafting Team has developed four drafts of standard COM-003-1 for comment and ballot. The last successive ballot received a 53.57 percent approval rating, an increase of only 3 percent over its previous ballot.

After careful consideration of available options, the next step in the standard development process is to convene an industry conference. This conference, scheduled for February 14-15, 2013, will review and discuss the following topics:

- **NERC CEO, FERC, and Board of Trustees' Perspectives on the Need for a Standard**
- **COM-003-1 Development History and Roundtable Discussion**
- **COM-003-1 Industry Comment Themes and Roundtable Discussion**
- **Presentation on Effective Operator Communications**
- **Compliance Considerations for Communication Standards**
- **Working Sessions on Communication Standard Development**

For more information or assistance, please contact Howard Gugel (via email) or at (609) 651-2269 or Joseph Krisiak (via email) or at (404) 446-2577.

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Agenda – Open Session
Electricity Sub-Sector Coordinating Council

January 24, 2013 | 3:00–4:00 p.m. Eastern

Dial-in: 1-800-735-5968
No Code Needed

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines*

Regular Agenda

1. **Key Issues Update**
   a. ES-ISAC Update – Recent Alerts and Advisories
   b. 2013 ES-ISAC Goals
2. **Summary of Discussions During Closed Session**
   a. Status of ESCC Actions*
   b. 2013 NERC Critical Infrastructure Protection Committee (CIPC) – Work Plan Update
   c. HILF Coordinated Action Plan Phase 2 Update
   d. Planning – Grid Security Exercise 2013 – GridEx II
   e. External Affairs Update
   f. Proposed Policy-Level Emergency Tabletop
   g. FERC NOPR re: Geomagnetic Disturbances

Future Meetings #

Thursday	April 18, 2013	8:00 a.m.– 3:00 p.m.	CLOSED and OPEN In-person meeting, NERC offices, Washington D.C.
Thursday	July 11, 2013	2:00–4:00 p.m.	CLOSED and OPEN conference call
Thursday	October 3, 2013	8:00 a.m.–3:00 p.m.	CLOSED and OPEN In-person meeting, NERC offices, Washington D.C.

All times Eastern

*Background materials included.

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Antitrust Compliance Guidelines

I. General

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.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

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ESCC Actions and Status

January 24, 2013

Item	Action	Assigned to	Due by	Status
June 21, 2011 #1	Industry response to the Aurora vulnerability. As this work progresses, prepare training and information to describe mitigation results by the industry, relay manufacturers, and IEEE standards development.	T. Roxey	Q1 2013	Open As part of NERC's periodic update regarding industry's actions to mitigate the Aurora vulnerability, document IEEE's efforts to develop a protective controls standard.
March 15, 2012 #3	Consider supply chain vulnerabilities that may affect the reliability of the bulk power system; starting with high voltage transformers.	RISC Committee	TBD	Open "Tracking of Spare Equipment" being considered by NERC Reliability Issues Steering Committee.
March 15, 2012 #4	Continue with the approach used in the Coordinated Action Plan to prioritize and address the recommendations identified in the HILF Task Force reports.	S. Brindley	Q2 2013	Open Assess the extent to which the HILF Task Force recommendations are being considered and addressed by NERC and the industry. Continue to monitor progress.
September 27, 2012 #2	Continue to develop the Severe Emergency Tabletop Exercise, considering input from the ESCC and the GCC.	NERC staff	Jan 24, 2012	Open Further develop the proposed scope and objectives and recommend how best to implement.
November 29, 2012 #1	Share with ESCC members NERC's draft response to the FERC NOPR regarding GMD.	NERC staff	TBD	Complete – NERC draft shared with ESCC members December 10, 2012.

Item	Action	Assigned to	Due by	Status
November 27, 2012 #2	Prepare a 1-page brief for chief executive officers highlighting observations from NERC's GridSecCon 2012	NERC staff	Jan 2012	Open
November 27, 2012 #3	Share DOE's Hurricane Sandy after-action report with the ESCC.	DOE	TBD	Open

141 FERC ¶ 61,045
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM12-22-000]

Reliability Standards for Geomagnetic Disturbances

(Issued October 18, 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 direct the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, to submit for approval Reliability Standards that address the impact of geomagnetic disturbances (GMD) on the reliable operation of the Bulk-Power System. The Commission proposes to do this in two stages. In the first stage, the Commission proposes to direct NERC to file, within 90 days of the effective date of a final rule in this proceeding, one or more Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, the Commission proposes to direct NERC to file, within six months of the effective date of a final rule in this proceeding, one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going

assessments of the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit. This second stage would be implemented in phases, focusing first on the most critical Bulk-Power System assets.

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:

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SUPPLEMENTARY INFORMATION:

141 FERC ¶ 61,045
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Standards for Geomagnetic Disturbances Docket No. RM12-22-000

NOTICE OF PROPOSED RULEMAKING

(Issued October 18, 2012)

1. Pursuant to section 215(d)(5) of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) proposes to direct the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), to file for approval with the Commission Reliability Standards (GMD Reliability Standards) that address the risks posed by geomagnetic disturbances (GMD) to the reliable operation of the Bulk-Power System.[2] The Commission proposes to direct NERC to develop the GMD Reliability Standards in two stages. In the first stage, within 90 days of the effective date of a final rule in this proceeding, NERC would file one or more proposed Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the

[1] 16 U.S.C. 824o(d)(5) (2006).

[2] "A geomagnetic disturbance occurs when the magnetic field embedded in the solar wind is opposite that of the earth. This disturbance, which results in distortions to the earth's magnetic field, can be of varying intensity and has in the past impacted the operation of pipelines, communications systems, and electric power systems." Oak Ridge National Laboratory, *Electric Utility Industry Experience with Geomagnetic Disturbances* at xiii (1991), *available at* http://www.ornl.gov/~webworks/cpr/v823/rpt/51089.pdf.

effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, within six months of the effective date of a final rule in this proceeding, NERC would file one or more proposed Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD.[3] This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents (GICs) from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.[4] This second stage would be implemented in phases, focusing first on the most critical Bulk-Power System assets.

[3] 16 U.S.C. 824o(a)(4) (2006).

[4] Some examples of automatic blocking include series line capacitors, transformer neutral GIC blocking and/or reduction devices, and selective tripping of vulnerable

(continued…)

2. We take this action based on government-sponsored studies and NERC studies that conclude that GMD events can have an adverse, wide-area impact on the reliable operation of the Bulk-Power System.[5] In a 2010 study prepared for the Commission, Department of Energy, and Department of Homeland Security, the Oak Ridge National Laboratory reported that GMD events can develop quickly over large geographic footprints, having the capability to produce geographically-large outages and significant damage to Bulk-Power System equipment.[6]

3. The seriousness of the risk posed by GMDs to the reliable operation of the Bulk-Power System was expressed at a Technical Conference held on April 30, 2012.[7] At the Technical Conference, several panelists indicated that severe GMD events could potentially compromise the reliable operation of the Bulk-Power System, with some

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assets. Automatic blocking measures can also include the use of relays that can be set so that they are activated only when needed.

[5] *See, e.g.,* The Oak Ridge National Laboratory prepared a study consisting of six technical reports (collectively, "Oak Ridge Study") on the effects of electromagnetic pulses on the Bulk-Power System. *Available at* http://www.ornl.gov/sci/ees/etsd/pes/ferc_emp_gic.shtml; North American Electric Reliability Corp., 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System at 85 (February 2012) (*NERC Interim GMD Report*), *available at* http://www.nerc.com/files/2012GMD.pdf; North American Electric Reliability Corp., *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System* at 68 (June 2010) (*HILF Report), available at* http://www.nerc.com/files/ HILF.pdf.

[6] Oak Ridge National Laboratory, *Electromagnetic Pulse: Effects on the U.S. Power Grid:Meta-R-319* at pages 1-30, 1-31, 4-1 (January 2010) (*Oak Ridge Study 319 Report*), *available at* http://www.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf.

[7] Written statements presented at the Technical Conference, post-Technical Conference comments, and Technical Conference transcript are accessible through the Commission's eLibrary document retrieval system in Docket No. AD12-13-000.

noting as an example the GMD-induced disruption of the Hydro-Québec grid in 1989.[8] At the Technical Conference, panelists stated that the current 11-year solar activity cycle is expected to hit its maximum activity in 2013 and large solar events often occur within four years of such a cycle maximum.[9] While strong GMDs are infrequent events, their potential impact on the reliable operation of the Bulk-Power System (e.g., widespread blackouts) requires Commission action under section 215(d)(5) of the FPA.[10]

[8] *See, e.g.*, Statement of Scott Pugh, U.S. Department of Homeland Security at 2 (citing 1989 Hydro-Québec blackout); Statement of Frank Koza, PJM Interconnection, L.L.C. at 1 ("The combination of half-cycle transformer saturation and increased reactive power consumption can lead to voltage collapse and blackouts if not properly managed."); Statement of John Kappenman at 8 ("The bulk power system is the nation's most important critical infrastructure and unlike other threats, a severe geomagnetic storms [sic] can impose a near simultaneous nationwide crippling threat to this vital infrastructure."); Statement of Gerry Cauley, NERC at 1 ("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.").

[9] April 30, 2012 Technical Conference Tr. 84:14-19 (Pugh); 106:9-15, 169:1-19 (Murtagh).

[10] 16 U.S.C. 824o(d)(5); *see also Transmission Relay Loadability Reliability Standard*, 134 FERC ¶ 61,127, at P 25 (2011) (explaining that under section 215(d)(5) "the Commission, and not just the ERO, has the responsibility and authority to identify 'specific matters' that it considers appropriate to carry out section 215. Section 215 establishes a paradigm by which both the Commission and the ERO are responsible for identifying reliability gaps—the ERO through its Reliability Standards development process, where it can independently identify areas of concern and develop Standards to address them; and the Commission through its review of proposed Reliability Standards and authority to direct modifications or new Standards that address specific issues necessary to effectuate the purposes of section 215.").

4. Currently, GMD vulnerabilities are not adequately addressed in the Reliability Standards.[11] This constitutes a reliability gap because, as discussed below, GMD events can cause the Bulk-Power System to collapse suddenly and can potentially damage the Bulk-Power System.

5. GMD events affect the Bulk-Power System by introducing geomagnetically-induced currents[12] that can cause "half-cycle saturation" of certain high-voltage Bulk-Power System transformers.[13] Half-cycle saturation of transformers can lead to increased consumption of reactive power and creation of disruptive harmonics that can cause the sudden collapse of the Bulk-Power System.[14] Further, half-cycle saturation from GICs can potentially damage Bulk-Power System transformers because of overheating.[15]

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[11] NERC Reliability Standard IRO-005-3a (Reliability Coordination — Current Day Operations), Requirement R3, is the only existing requirement that discusses GMDs. Requirement R3 requires reliability coordinators to make transmission operators and balancing authorities aware of GMD forecast information and assist as needed in the development of response plans, but it does not require steps for mitigating the effects of GMD events.

[12] GIC is an electrical current created by a solar event that appears as direct current to the bulk electric system. North American Electric Reliability Council, *March 13, 1989 Geomagnetic Disturbance* at 36 (1989), *available at* http://www.nerc.com/files/1989-Quebec-Disturbance.pdf. Automatic blocking prevents or reduces GICs flows into protected Bulk-Power System components without operator intervention. *NERC Interim GMD Report* at 73.

[13] NERC Interim GMD Report at iii-iv. Half-cycle saturation is an abnormal operating condition whereby a transformer operates outside nominal voltage design values, saturating the transformer core with magnetic flux and forcing magnetic flux into other parts of the transformer. *Id.* at 25.

[14] *Id.* at 3 ("GMD can have … a wide range of impacts on power apparatus and power system operations. The effects on apparatus range from nuisance events, such as tripping of electrical equipment, radio interference, and control malfunctions, to large-

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Permanent damage to large transformers due to GICs can lead to restoration delays for the power grid.[16] For example, the Oak Ridge Study assessed the effects of a "1-in-100 year" geomagnetic storm on the modern Bulk-Power System.[17] The Oak Ridge Study simulation concluded that such an event could put a significant number of Bulk-Power System transformers at risk for failure or permanent damage.[18] The Oak Ridge Study simulation also found that the effects of a GMD event may be substantially larger if it

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scale events, such as voltage and reactive power fluctuations, local disruption of service, limited equipment failure, and potential voltage instability resulting in uncontrolled cascading of the bulk power system.").

[15] While disagreements exist as to the likely severity of transformer damage from GMDs compared with the likelihood of voltage collapse due to increased reactive power absorption arising from GMDs, there appears to be a consensus that GMDs can cause at least some damage to Bulk-Power System transformers. *See*, *e.g.*, Comments of the North American Electric Reliability Corporation, Docket No. AD12-13-000, at 5 (filed May 21, 2012) ("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.").

[16] *Oak Ridge Study 319 Report* at pages 4-1, 4-3 ("The recovery could plausibly extend into months in many parts of the impacted regions … These multi-ton apparatus [transformers] generally cannot be repaired in the field, and if damaged in this manner, they need to be replaced with new units, which have manufacture lead times of 12 months or more in the world market."); NERC Interim GMD Report at iv ("[R]estoration times for system collapse due to voltage instability would be a matter of hours to days, while replacing transformers requires long-lead times (a number of months) to replace or move spares into place, unless they are in a nearby location. Therefore, the failure of a large numbers [sic] of transformers would have considerable impacts on portions of the system.").

[17] *Oak Ridge Study 319 Report* at page 3-22.

[18] *Id*. at page 1-14, Tables 4-1, 4-2, 4-3 (listing numbers of at-risk transformer).

occurred at lower latitudes.[19] Estimates prepared by the National Research Council of the National Academies concluded that these events have the potential to cause wide-spread, long-term losses with economic costs to the United States estimated at $1-2 trillion and a recovery time of four to ten years.[20] The NERC Interim GMD Report concluded, on the other hand, that the worst-case scenario is "voltage instability and subsequent voltage collapse," and cites as an example the 1989 Hydro-Québec blackout.[21] While the conclusions of these reports differ significantly, our proposed action is warranted by even the lesser consequence of a projected widespread blackout without long-term, significant damage to the Bulk-Power System. Taking steps to prevent such blackouts is consistent with maintaining the reliable operation of the Bulk-Power System.[22]

6. Given the potentially severe, wide-spread impact to the reliable operation of the Bulk-Power System from GMD events and the absence of existing Reliability Standards to address it, the Commission proposes to direct the ERO to file with the Commission for

[19] *Id.* at pages 3-25, 3-26.

[20] National Research Council of the National Academies, *Severe Space Weather Events—Understanding Societal and Economic Impacts: A Workshop Report* at 4 (2008) (*NAS Workshop Report*), *available at* http://www.nap.edu/catalog/12507.html.

[21] NERC Interim GMD Report at 69.

[22] 16 U.S.C. 824o(a)(4) ("The term '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 cybersecurity incident, or unanticipated failure of system elements.").

approval Reliability Standards that address this reliability gap. In proposing to address the risks posed by GMDs in two stages, the Commission finds that there are Reliability Standards that the ERO can develop and file quickly (i.e., requiring GMD operational procedures) to mitigate the effects of GMDs while it develops other Reliability Standards that require owners and operators of the Bulk-Power System to assess the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.[23]

7. We recognize that, depending on the results of the initial and on-going assessments that would be required under this proposed rule, there could be substantial costs associated with some measures to protect against damage to the Bulk-Power System

[23] *See infra* PP 34-36.

from GMDs.[24] In determining that it is appropriate to issue this proposed rule, however, we have compared such costs against the societal harms, including the potential costs of equipment damage or prolonged blackouts, that could result from taking no action.[25]

I. Background

A. Section 215 and Mandatory Reliability Standards

8. Section 215 of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[26] Once approved, the Reliability Standards may be enforced in the United States by the ERO, subject to Commission oversight, or by the Commission independently.

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[24] For example, estimates for installing blocking devices on transformers range from $100,000 to $500,000 for each affected transformer. *See* Foundation for Resilient Societies, Comments on Advance Notice of Proposed Rulemaking (ANPR) of the Nuclear Regulatory Commission Relating to the Prevention and Mitigation of Station Blackout, filed in Docket No. AD12-13-000, at 13 (May 4, 2012) (citing $500,000 installed costs per transformer); MITRE Corp., Impacts of Severe Space Weather on the Electric Grid, at 66 (November 2011) (citing $100,000 cost for neutral-current-blocking-capacitors per transformer), *available at* http://www.fas.org/irp/agency/dod/jason/spaceweather.pdf.

[25] For example the estimated total cost of the August 2003 four-day blackout in the United States is between $4 billion and $10 billion, with the Department of Energy calculating the total cost to be $6 billion. Electricity Consumers Resource Council, The Economic Impacts of the August 2003 Blackout, *available at* http://www.elcon.org/Documents/EconomicImpactsOfAugust2003Blackout.pdf. *See also supra* P 5 (citing estimates by the National Research Council of the National Academies of potentially $1-2 trillion in economic costs from a severe GMD event).

[26] 16 U.S.C. § 824o (2006).

9. Pursuant to section 215(d)(5) of the FPA, the Commission has the authority, upon its own motion or upon complaint, to order the ERO to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to carry out section 215 of the FPA.[27]

B. Studies of GMD Events on the Bulk-Power System

10. The impact of GMDs on the Bulk-Power System has been evaluated in several government-sponsored studies and NERC reports. The EMP Commission issued reports assessing the threat to the United States from Electromagnetic Pulse (EMP) attack in 2004 and 2008, which also addressed the effects of geomagnetic storms on the electric power infrastructure.[28] The NAS Workshop Report addressing the impact of severe space weather events was released in 2008. The Oak Ridge National Laboratory issued the Oak Ridge Study on the effects of electromagnetic pulses on the Bulk-Power System in January 2010. The NERC HILF Report on high-impact, low-frequency risks to the Bulk-Power System was issued in June 2010.[29] In February 2012, NERC issued the NERC Interim GMD Report evaluating the effects of GMDs on the Bulk-Power System.

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[27] 16 U.S.C. 824o(d)(5); 18 CFR 39.6(f) (2012).

[28] These reports are accessible at the Commission to Assess the Threat to the United States from Electromagnetic Pulse (EMP) Attack website at http://www.empcommission.org/.

[29] The HILF Report was prepared by NERC, Department of Energy, and a steering committee comprised of industry and risk experts and was approved by the NERC Board of Trustees on May 17, 2010. *HILF Report* at 2.

11. The Commission conducted a staff-led Technical Conference on April 30, 2012 to discuss the effects of GMDs on the reliable operation of the Bulk-Power System. NERC, government agencies, industry stakeholders, and other interested entities attended the Technical Conference and submitted post-Technical Conference comments.

C. Effects of GMD Events on the Bulk-Power System

12. The interaction of the Earth's magnetic field and solar events can cause low frequency GICs to flow along the surface of the Earth and in the oceans. Reliability issues arise when GICs enter the Bulk-Power System from the Earth. Since many Bulk-Power System transformers are grounded, the GIC appears as electrical current to the Bulk-Power System and flows through the ground connection and conductors, such as transformers and transmission lines.[30]

13. GICs can cause transformer cores to become "saturated," resulting in loss of reactive power (VARs), the introduction of harmonic distortions, and possible physical damage to the transformer.[31] GICs enter the Bulk-Power System through the grounded neutrals of transformers and are responsible for forcing their metal cores into saturation.[32]

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[30] Oak Ridge National Laboratory, *Electromagnetic Pulse: Effects on the U.S. Power Grid (Meta-R-322)* at page 1-1 (January 2010) (*Oak Ridge Study 322 Report*), *available at* http://www.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-322.pdf.

[31] *HILF Report* 70-71. Harmonics are currents or voltages with frequencies that are integer multiples of the fundamental power frequency (i.e., 60 Hz in the United States). *See* Northeast Power Coordinating Council, Inc. Glossary of Terms, *available at* https://www.npcc.org/Standards/Directories/Glossary%20of%20Terms.pdf. They can cause overcurrent relays to automatically trip components (e.g., capacitor banks and static VAR compensators) from service. *HILF Report* at 71. Automatic removal of such components can further exacerbate system voltages already reduced by the GIC-related

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A primary effect of saturation is the potential for transformer damage through the overheating of internal components.[33] Saturation is also responsible for secondary effects, such as the production of harmonics that are not present during normal Bulk-Power System operation and for substantially increasing the transformer's absorption of reactive power from the system, thus requiring significant amounts of additional voltage support to compensate for reactive power absorption. Harmonic production and reactive power absorption may interfere with normal system operations creating secondary effects on other Bulk-Power System facilities. These primary and secondary effects can occur almost simultaneously over a large geographic area, resulting in a multiple contingency outage that has the potential to cascade across the Bulk-Power System.[34]

14. The Oak Ridge Study identified factors that determine the severity of GMD events, including: (1) location and strength of the underlying solar event; (2) ground conductivity in the affected locations (i.e., the geology of the location); (3) orientation of

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absorption of reactive power.

[32] *Oak Ridge Study 322 Report* at pages 1-1, 7-11.

[33] *HILF Report* at 70 ("Transformers experience excessive levels of internal heating brought on by stray flux when GICs cause the transformer's magnetic core to saturate and spill flux outside the normal core steel magnetic circuit. Previous well-documented cases have noted heating failures that caused melting and burn-through of large-amperage copper windings and leads in these transformers (Figure 9)."); *Oak Ridge Study 319 Report* at page 2-29 ("Also of note from this particular [March 1989] storm is strong evidence that GIC-induced half-cycle saturation of transformers can indeed produce enough heat to severely damage or even destroy exposed large power transformers.").

[34] *HILF Report* at 71-72.

the transmission lines; (4) length of transmission lines; and (5) grid construction.[35] A solar disturbance can cause near-simultaneous, multi-point failures that can trigger collapse of the Bulk-Power System.[36]

II. Discussion

15. As discussed below, the Commission finds that there is a gap in the Reliability Standards regarding GMDs. Therefore, in order to carry out section 215 of the FPA, the Commission proposes to direct the ERO to develop and file for approval Reliability Standards that address the potentially severe, wide-spread impact of GMD events on the reliable operation of the Bulk-Power System.

16. We propose that the ERO develop and file the GMD Reliability Standards in two stages. In the first stage, within 90 days of the effective date of a final rule in this proceeding, the Commission proposes to direct NERC to file one or more Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, the Commission proposes to direct NERC to file one or more Reliability Standards, within six months of the effective date of a final rule in this proceeding, that require owners and operators of the Bulk-Power System to assess the impact of GMDs on Bulk-Power System equipment

[35] *Oak Ridge Study 319 Report* at page 2-5.

[36] *Id.* at pages 4-1, 4-2. One example cited in the Oak Ridge Study is the March 13, 1989 solar disturbance that triggered the collapse of the Hydro-Québec power grid, which went from normal to a situation where it sustained seven contingencies in an elapsed time of 57 seconds. *Id.*

and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.[37]

17. In proposing to direct the ERO to submit Reliability Standards that address the impact of GMD events on the reliable operation of the Bulk-Power System, we are not proposing specific requirements or otherwise pre-judging what the ERO may eventually submit. Instead, we identify concerns that we believe should be addressed in any GMD Reliability Standards. We expect the ERO to support its proposed Reliability Standards and explain how they address the Commission's concerns.

[37] The second stage Reliability Standards would not require owners and operators of the Bulk-Power System to protect the Bulk-Power System beyond what is found to be required based on the initial and ongoing assessments.

A. Reliability Standards Requiring Operational Procedures

18. Requiring operational procedures, while not a complete solution, constitutes a first step to addressing the GMD reliability gap because they can be implemented relatively quickly.[38] The Commission does not propose to require the ERO or owners and operators of the Bulk-Power System to adopt any particular operational procedures. Owners and operators of the Bulk-Power System are the most familiar with the equipment and system configurations. Accordingly, we propose that the ERO file one or more Reliability Standards requiring owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System based on the following guidance.

19. Operational procedures may help alleviate abnormal system conditions due to transformer absorption of reactive power during GMD events, helping to stabilize system voltage swings, and may potentially isolate some equipment from being damaged or misoperated. The NERC Interim GMD Report identifies examples of operational procedures to mitigate GMD events (i.e., the effects of GICs), including: reduction of equipment loading (e.g., by starting off-line generation), unloading the reactive load of operating generation, reductions of system voltage, and system and/or equipment

[38] NERC Interim GMD Report at 79 ("Operating procedures are the quickest way to put in place actions that can mitigate the adverse effects of GIC on system reliability … Both system operating and transmission owner organizations need to have appropriate procedures and training in place.").

isolation through reconfiguration of the transmission system.[39] Some entities already have operational procedures to mitigate the effect of GICs on the Bulk-Power System utilizing system resources.[40] The Commission expects that the ERO and owners and operators of the Bulk-Power System will draw on industry's experience in developing and implementing existing operational procedures. Given that experience, we propose to direct NERC to file, within 90 days of the effective date of a final rule in this proceeding, proposed Reliability Standards that require the development and implementation of operational procedures. While this deadline is aggressive, mandatory and enforceable Reliability Standards requiring owners and operators to implement operational procedures should be established quickly to afford some level of uniform protection to the Bulk-Power System against GMD events. As discussed above, the impact of GMDs on the Bulk-Power System has been studied extensively for many years, laying the foundation for the prompt development of these first stage Reliability Standards. Moreover, the fact that operational procedures are already in place in some areas should allow for faster development and implementation of these Reliability Standards.

20. While the proposed Reliability Standards should not necessarily specify what operational procedures must be adopted, the ERO should give owners and operators of

[39] NERC Interim GMD Report at 80-81.

[40] *See*, *e.g.*, PJM Interconnection, L.L.C., Manual 13: Emergency Operations at 47, *available at* http://www.pjm.com/~/media/documents/manuals/m13.ashx; Northeast Power Coordinating Council, Inc., Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems, *available at* https://www.npcc.org/Standards/Procedures/c-15.pdf.

the Bulk-Power System guidance as to what procedures have been or are expected to be effective in mitigating the effects of GMDs consistent with the reliable operation of the Bulk-Power System. Moreover, the proposed Reliability Standards should address the coordination of operational procedures among responsible entities across regions.[41] Since there could be potential equipment damage resulting from a GMD event, the proposed Reliability Standards should also address operational procedures for restoring GMD-impacted portions of the Bulk-Power System that take into account the potential for equipment that is damaged or out-of-service for an extended period of time.

21. We do not propose to direct a specific implementation schedule for the proposed Reliability Standards, but the Commission encourages the ERO to require owners and operators of the Bulk-Power System to implement the required operational procedures 90 days after Commission approval of the Reliability Standards. Following implementation, the Commission proposes to require NERC to provide periodic reports assessing the effectiveness of the operational procedures in mitigating the effects of GMD events. In addition, NERC should periodically review the required operational procedures and recommend to owners and operators that they incorporate lessons-learned and new research findings.

22. In addition to developing Reliability Standards that require operational procedures during the first stage, the Commission also proposes to accept aspects of the "Initial

[41] NERC Interim GMD Report at 79 ("The [operating] procedures of these organizations need to be coordinated with each other and with their neighboring organizations.").

Actions" proposal set forth in NERC's May 21, 2012 post-Technical Conference comments. Specifically, NERC proposed to "identify facilities most at-risk from severe geomagnetic disturbance" and to "conduct wide-area geomagnetic disturbance vulnerability assessment."[42] As noted in NERC's comments regarding the vulnerability assessments, special attention would be given to evaluating critical transformers (e.g., step-up transformers at large generating facilities). We agree with NERC that critical Bulk-Power System facilities should be evaluated for GMD vulnerability as an initial action. In addition, as part of the initial action, special attention should be given to those Bulk-Power System facilities that provide service to critical and priority loads.[43] The Commission, therefore, proposes to direct NERC to conduct this "initial action" simultaneously with the development and implementation of the first stage GMD Reliability Standards. The Commission seeks comment from NERC and other interested entities on all aspects of this proposal.

[42] NERC Comments at 8-9 ("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 … special attention will be given to the evaluation of critical transformers, such as generator step-up units at large generating facilities … 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.").

[43] The NERC Severe Impact Resilience Task Force identified critical and priority loads in a report. *See* Severe Impact Resilience: Considerations and Recommendations at 26 (Accepted by NERC Board of Trustees on May 9, 2012), *available at* http://www.nerc.com/docs/oc/sirtf/SIRTF_Final_May_9_2012-Board_Accepted.pdf.

B. Second Stage Reliability Standards

23. To address GMDs comprehensively, the Commission proposes to direct NERC to develop, in a second stage, Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of GMDs on Bulk-Power System equipment and on the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit. While the Commission proposes to direct the ERO to submit the proposed second stage Reliability Standards within six months of the effective date of a final rule in this proceeding, the Commission seeks comment on the feasibility of a six-month deadline.

24. We propose to direct the filing of these second stage GMD Reliability Standards because of two concerns with relying on operational procedures alone: (1) owners and operators of the Bulk-Power System may not have enough time to initiate effective

operating procedures after being warned of a GMD event; and (2) operational procedures may not prevent permanent damage to Bulk-Power System equipment.[44] Current GMD forecasting methods provide limited time for operators to react once a GMD warning is issued.[45] Even with enough time to react, the Oak Ridge Study found that, given a large enough GMD event, operational procedures are unlikely to provide the substantial levels of GIC reduction needed to limit the potential for permanent damage to transformers.[46] The Oak Ridge Study and the HILF Report also found that widespread damage to Bulk-Power System transformers could result in prolonged outages.[47]

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[44] NERC Interim GMD Report at 10 ("These warning can be received as short as 30 minutes before the onset of an impending geomagnetic storm."). At the April 30, 2012 Technical Conference, Mr. Murtagh, Program Coordinator at the National Oceanic and Atmospheric Administration's Space Weather Prediction Center, stated that a warning is issued when a GMD event reaches the NASA Advanced Composition Explorer (ACE) satellite and at that point, in some cases, it could be 20 or 30 minutes before the event reaches the Earth's magnetic field. April 30, 2012 Technical Conference Tr. 170:5-22 (Murtagh).

[45] Mr. Pugh, from the U.S. Department of Homeland Security's Interagency Programs Office Science & Technology Directorate, stated that the operators in the 1989 Hydro-Québec blackout only had 90 seconds to react, which was insufficient to "prevent a massive blackout and significant equipment damage." April 30, 2012 Technical Conference Tr. 12:4-7 (Pugh).

[46] *Oak Ridge Study 322 Report* at pages ix and 1-1.

[47] *HILF Report* at 12 ("The physical damage of certain system components (e.g. extra-high-voltage transformers) on a large scale, as could be effected by any of these threats, could result in prolonged outages as procurement cycles for these components range from months to years."); *Oak Ridge Study 319 Report* at pages 2-33, 2-34 ("An especially large storm or GIC event could plausibly create the potential for widespread failure of many exposed transformers and hamper rapid restoration capabilities. In extreme cases, where replacements may take months, a situation may exist where the demand for electric service can only be partially supplied, raising the prospect of rationing and rotating blackouts to regions that are unable to be fully served.").

25. We recognize that the NERC Interim GMD Report concludes that a prolonged blackout due to extensive damage to Bulk-Power System transformers is less likely than voltage instability due to increased reactive power consumption and loss of reactive power support, which can lead to blackouts like the 1989 Hydro-Québec event.[48] The Commission's proposed two-stage approach recognizes this difference by focusing first on the development of Reliability Standards requiring operational procedures in a relatively short time frame. The Commission proposes to give NERC and owners and operators of the Bulk-Power System more time to perform, in the second stage, initial and on-going assessments. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit. Moreover, although the NOPR proposes that the second stage

[48] NERC Interim GMD Report at vi.

Reliability Standards be filed within six months of the effective date of the final rule, we seek comment on the feasibility of that deadline.

26. Below, we offer guidance on the assessments of Bulk-Power System vulnerability to GMDs and potential measures for automatically protecting critical or vulnerable components. In addition, recognizing the potential for substantial investments of time and resources to implement these Reliability Standards, we offer guidance on an implementation schedule, which will likely consist of an extended, multi-phase process. The Commission seeks comment from NERC and other interested entities on all aspects of this proposal.

1. GMD Vulnerability Assessments of the Bulk-Power System

27. The Commission proposes to direct the ERO to develop Reliability Standards that require owners and operators of the Bulk-Power System to conduct vulnerability assessments to determine how critical or vulnerable Bulk-Power System components react to simulated GICs of varying intensities.[49] The Commission proposes to direct the ERO to consider the following parameters as it develops the Reliability Standards.[50]

[49] To accurately simulate the impact of GMDs on the Bulk-Power System, the assessments should consider the impact of GICs that may enter the system through transformers that are not treated as part of the bulk electric system and any impact that the non-bulk electric system transformers may have on the reliability of the Bulk-Power System. We do not propose, however, that equipment falling outside of our jurisdiction would be required to be protected under the proposed Reliability Standard.

[50] The vulnerability assessments in the second phase Reliability Standards are distinct from the "initial action" evaluations, discussed above, which NERC proposed to do and we propose to have NERC conduct simultaneous with the development and implementation of the first phase Reliability Standards. We expect, however, that the

(continued…)

28. First, the Reliability Standards should contain uniform evaluation criteria for owners and operators to follow when conducting their assessments. As the Commission noted with respect to other reliability assessments, uniformity increases the accuracy of transmission system reliability assessments and consequently enhances overall reliability.[51]

29. Second, the assessments should, through studies and simulations, evaluate the primary and secondary effects of GICs on Bulk-Power System transformers, including the effects of GICs originating from and passing to other regions.

30. Third, the assessments should evaluate the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the anticipated loss of critical or vulnerable devices or elements resulting from GIC-related issues.[52]

31. Fourth, in conjunction with assessments by owners and operators of their own Bulk-Power System components, wide-area or Regional assessments of GIC impacts should be performed. A severe GMD event can cause simultaneous stresses at multiple

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analyses performed in the "initial action" evaluations will be used to quickly identify and protect the most critical and vulnerable Bulk-Power System components once the second stage Reliability Standards become effective.

[51] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1298, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[52] The Oak Ridge Study assessment included GMD modeling, simulation and review of storm impacts, power grid GIC flows and reactive power demands, transformer heating and risk of potential damage to transformers. *See generally Oak Ridge Study 319 Report*.

locations on the Bulk-Power System, potentially resulting in a multiple-outage event.[53] In predicting GIC flows, it is necessary to take into consideration the network topology as an integrated whole (i.e., on a wide-area basis).[54]

32. Fifth, the assessments should be periodically updated, taking into account new facilities, modifications to existing facilities, and new information, including new research on GMDs, to determine whether there are resulting changes in GMD impacts that require modifications to Bulk-Power System mitigation schemes.

33. The Commission seeks comments from NERC and other interested entities on all aspects of this proposal.

2. Automatic GIC Blocking for Critical or Vulnerable Bulk-Power System Components

34. While we do not propose to require a particular solution in the second stage Reliability Standards to address GMDs, we expect that some assessments will demonstrate that automatic blocking is necessary in some instances. The Commission, above, proposes to direct the ERO to develop Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. Automatic blocking measures address the major concerns with relying exclusively on operational procedures to mitigate GMDs (i.e., the

[53] *Oak Ridge Study 319 Report* at pages A1-1, A1-2.

[54] *Id.* at page 1-17.

short period of time to react to a GMD event and the potential consequences of not reacting fast enough). Blocking can prevent the flow of GICs through power transformers and the Bulk-Power System.[55] Eliminating GICs in transformers prevents transformer core saturation and, thus, mitigates or prevents the effects of GMDs on the Bulk-Power System (i.e., transformer overheating, reactive power absorption, and harmonic generation).

35. The Commission does not propose to direct the ERO to require a particular automatic blocking technology, where blocking is necessary. Instead, the Commission proposes to direct the ERO to identify in the proposed Reliability Standards what would constitute appropriate automatic blocking measures. In defining what is an appropriate blocking measure, the ERO should address: (1) its feasibility and effectiveness; and (2) its ability to operate without adversely impacting the reliable operation of the Bulk-Power System. The Commission proposes that the Reliability Standards should include a means by which the ERO can verify that selected blocking measures are appropriate.

36. The use of automatic blocking devices, such as transmission line series capacitors and transformer neutral blocking, are possible measures.[56] These devices block or reduce the flow of GIC in a power grid.[57] Although not a means for blocking GICs, another possible option is to improve the "withstand" capability of Bulk-Power System

[55] NERC Interim GMD Report at 73.

[56] *Oak Ridge Study 322 Report* at ix-x.

[57] *Id.*

components. The "withstand" capability, in this context, refers to a component's ability to withstand stresses imposed by GICs before suffering damage, but it does not prevent GICs from affecting the rest of the Bulk-Power System (e.g., it does not prevent the secondary effects of harmonics or increased reactive power consumption).[58] The ERO should consider whether the reliability goals of the proposed Reliability Standards can be achieved by a combination of automatic protection measures, including, for example, some combination of automatic blocking and improved "withstand" capability. In any event, the measures must be adequate to protect the reliability of the Bulk-Power System against the risks identified in the assessments.

37. The Commission seeks comments from NERC and other interested entities on all aspects of this proposal.

3. Implementation Schedule

38. The second stage Reliability Standards will likely require an extended, multi-phase implementation period given the time needed to conduct the required assessments and the time and cost of installing any required automatic protection measures. Although the Commission does not propose to direct the ERO to develop a specific implementation plan, we believe it would be appropriate for the proposed Reliability Standard to include an implementation schedule that requires owners and operators of the Bulk-Power System to prioritize implementation so that components considered vital to the reliable

[58] NERC Interim GMD Report at 67.

operation of the Bulk-Power System are provided with any necessary automatic protection measures in the earliest phase of the plan.[59]

39. The Commission seeks comments from NERC and other interested entities on an implementation plan.

III. Information Collection Statement

40. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules. 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 an agency 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. The Paperwork Reduction Act (PRA) requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or contained in a rule of general applicability.

41. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, ways to enhance the quality, utility, and clarity of the information to be collected,

[59] For example, critical Bulk-Power System equipment identified by NERC in the first stage "initial actions" assessments, discussed previously, should be protected in the earliest phase of the implementation plan.

and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

42. The Public Reporting Burden and cost related to the proposed rule in Docket No. RM12-22-000 are covered by, and already included in, the existing FERC-725, Certification of Electric Reliability Organization; Procedures for Electric Reliability (OMB Control No. 1902-0225). FERC-725 includes the ERO's overall responsibility for developing Reliability Standards, such as the Reliability Standards for Geomagnetic Disturbances.

43. Internal review: The Commission has reviewed the proposed changes and has determined that the changes are necessary to ensure the reliability and integrity of the Nation's Bulk-Power System.

44. Interested persons may obtain information on the reporting requirements by contacting: 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 on the requirements of this rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at oira_submission@omb.eop.gov. Please reference OMB Control No. 1902-0225, FERC-725 and the docket number of this proposed rulemaking in your submission.

IV. Environmental Analysis

45. 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.[60] 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.[61] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

46. The Regulatory Flexibility Act of 1980 (RFA)[62] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.

47. By only proposing to direct NERC, the Commission-certified ERO, to develop GMD Reliability Standards, this Notice of Proposed Rulemaking will not have a significant or substantial impact on entities other than NERC. The ERO develops and files with the Commission for approval Reliability Standards affecting the Bulk-Power System, which represents: (a) a total electricity demand of 830 gigawatts (830,000

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[60] *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).

[61] 18 CFR 380.4(a)(2)(ii).

[62] 5 U.S.C. 601-612.

megawatts) and (b) more than $1 trillion worth of assets. Therefore, the Commission certifies that this Notice of Proposed Rulemaking will not have a significant economic impact on a substantial number of small entities.

48. Any Reliability Standards proposed by NERC in compliance with this rulemaking will be considered by the Commission in future proceedings. As part of any future proceedings, the Commission will make determinations pertaining to the Regulatory Flexibility Act based on the content of the Reliability Standards proposed by NERC.

VI. Comment Procedures

49. 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 No. RM12-22-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

50. 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.

51. 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.

52. 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

53. 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.

54. 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.

55. 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.

By direction of the Commission.

Kimberly D. Bose,
Secretary.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Compliance Committee — Open Session

February 6, 2013 | 10:45 a.m.-Noon Pacific

Hotel del Coronado
1500 Orange Avenue
Coronado, CA 92118
800-468-3533

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines

Agenda

1. **Minutes* — Approve**
   a. November 6, 2012 Meeting
2. **Compliance Committee Self-Assessment Results* — Review**
3. **Reliability Assurance Initiative* — Information**
   a. Project Status
   b. Key Milestones and Deliverables
4. **Quarterly Report on Performance Metrics* — Information**
   a. Update on Quarterly Performance Metrics to Fulfill the Committee's Mandate Obligations
   b. Enforcement Metrics Development Update
5. **Compliance Enforcement Initiative (Find, Fix, Track, and Report) Filing* — Information**

*Background materials included.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Antitrust Compliance Guidelines

I. General

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.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Draft Minutes
Compliance Committee — Open Session

November 6, 2012 | 9:15 a.m. local time

JW Marriott New Orleans
614 Canal Street
New Orleans, LA 70130
504-525-6500

Chair Bruce Scherr convened a duly noticed open meeting of the Compliance Committee (the Committee) of the North American Electric Reliability Corporation on November 6, 2012 at 9:15 a.m. local time, and a quorum was declared present. The agenda is attached as **Exhibit A**.

Present at the meeting were: All Committee members, being Bruce Scherr, Chair, Vicky Bailey, Ken Peterson, Roy Thilly, Jan Schori and John Q. Anderson; Board members Tom Berry, Janice Case, Paul Barber, Fred Gorbet, Dave Goulding, and Gerry Cauley; and NERC staff members Charlie Berardesco, Earl Shockley, Ken Lotterhos, Rebecca Michael, and Tina Buzzard.

NERC Antitrust Compliance Guidelines

Mr. Scherr directed the participants' attention to the NERC Antitrust Compliance Guidelines.

Minutes

The Committee approved the August 15, 2012 meeting minutes as presented at the meeting.

Compliance Enforcement Initiative

Mr. Lotterhos provided an update on the Find, Fix, Track, and Report (FFT) initiative. He noted that since the last Committee meeting, NERC has made three additional filings for both spreadsheet notice of penalties (SNOPs) and FFTs, for an aggregate of 13 filings from September 2011 through September 2012. FERC has issued notices of no further review on the SNOP and NOP filings submitted through the end of September. In addition, Mr. Lotterhos noted that NERC had filed the FFT training materials with FERC in accordance with FERC's directive.

Mr. Lotterhos stated that in accordance with FERC's March 15, 2011 Order on the CEI, NERC is required to file a 12-month status report in March 2013. NERC Enforcement will be administering two industry surveys in early November 2012 and early January 2013 to gather registered entity input for the report.

Compliance Operations

Mr. Shockley provided an update on the Compliance Enforcement Initiative (CEI), noting the White Papers introducing the areas of fundamental change to the present compliance and enforcement processes and change state elements have been drafted and deliverables for both the March 2013 FERC filing and the achievement of the endstate developed. Key elements of the White Papers and path forward will be discussed more in-depth during the open Member Representatives Committee meeting.

Regional Entity Items

Mr. Dan Skaar, CEO of MRO, reviewed the improvements to Regional audit practices, noting the Regional Entities were performing a gap analysis to understand strengths and opportunities to facilitate the development of a more consistent approach to conducting compliance audits. He noted that the results of the assessment will provide valuable insights to training needs as NERC and the Regional Entities move to the next phase of the CEI.

Quarterly Statistics

Chair Scherr referenced the materials provided in the Agenda package. Committee members suggested enhancements to the Enforcement Metrics to provide further clarity on the status of violations.

There being no further business, and upon motion duly made and seconded, the meeting was adjourned at approximately 10:25 a.m. local time.

Submitted by,



Charles A. Berardesco
Secretary

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda Item 2
Compliance Committee Meeting
February 06, 2013

Summary of 2012 Board of Trustees Compliance Committee Survey

Compliance Committee Meeting
February 6, 2012

RELIABILITY | ACCOUNTABILITY






Overview

- NERC engaged TalentQuest to conduct its annual Board of Trustees Compliance Committee survey through an online methodology
- The Compliance Committee survey was administered from December 3 to December 28, 2012, to a total of six Committee members
- Five Committee members responded to the survey
  - Response rate of 83%

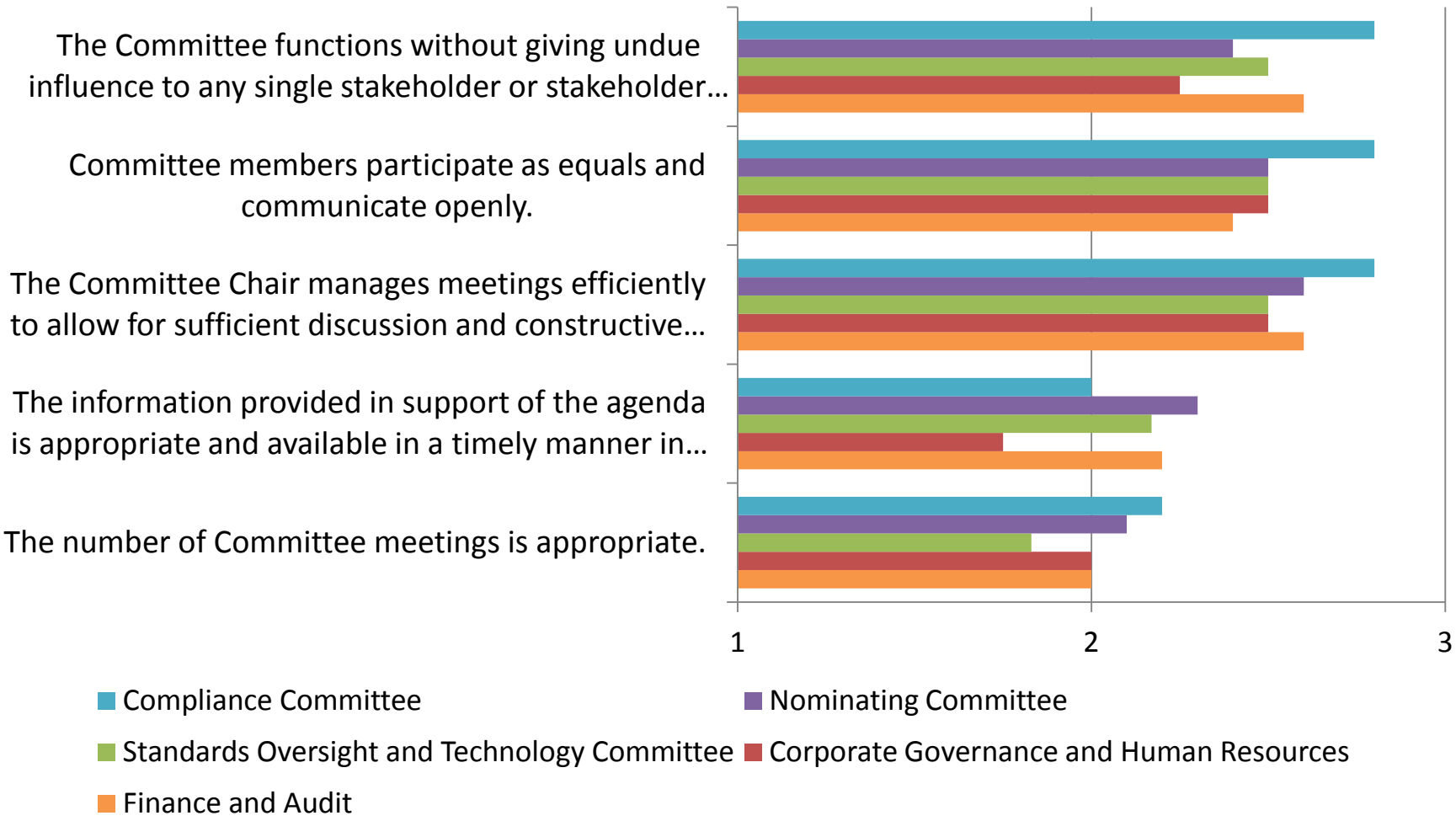
Rating Scale

- Respondents were asked to rate items on a 1 to 3 scale to indicate their evaluation for each rated item
  - 1 = Below Expectations (level of performance is clearly unsatisfactory)
  - 2 = Meets Expectations (meets the required standard of performance)
  - 3 = Above Expectations (far exceeds the required standard of performance)
- For any item rated "1" ("Below Expectations") or “No”, mandatory comments were required to explain the rationale for the rating or selection

Results Summary

- The overall Compliance Committee survey average was 2.2, with item averages ranging from 2.8 to 2.0
- Given the lowest item average was a 2.0, the Compliance Committee is seen to be operating at expectations or higher
- Review of cross-committee survey items finds the Compliance Committee rated the highest in all items except:
  - The information provided in support of the agenda is appropriate and available in a timely manner in advance of Board meetings

Committee Comparison



Agenda Item 3
Compliance Committee Meeting
February 6, 2013

Reliability Assurance Initiative

Action
Discussion

Background
The Reliability Assurance Initiative (RAI) was formally introduced at the November 2012 Board of Trustees (Board) meeting. The presentation outlined the core initiatives, anticipated timelines, and deliverables. Management will report on actions taken since the Board meeting, provide a project update, and further outline anticipated timelines.

Summary
Prior to the November Board meeting, NERC released the joint *Electric Reliability Organization (ERO) Enterprise White Paper* describing the desired end-state of compliance and enforcement as well as the four change state elements. Since the meeting two additional papers, *Restyling of Compliance Monitoring* and *Evaluation of Compliance Data Requirements* have been released in connection with the change state elements. In addition to the drafting of the papers, meetings have been held with representatives of the Member Representatives Committee and Trades to discuss the papers and gather comments and observations in consideration of the initiative, as well as the papers released to date.

Key elements that will be discussed include:

- Adjustments to the RAI approach and filing implications
- Updates on the status of the remaining white papers and related timelines
- RAI activities – update on projects and timelines
- Outlining future communication and engagements strategies

Agenda Item 4
Compliance Committee Meeting
February 6, 2013

Quarterly Report on Performance Metrics

Action
Informational

Background
NERC staff will present its regular quarterly report to the Committee and stakeholders on compliance statistics to fulfill the Committee's mandate obligations.

Summary
NERC has been working closely with the Regional Entities to develop a more consistent set of enforcement metrics. These metrics measure the performance (efficiency, quality and effectiveness) of key Compliance Enforcement Authority monitoring and enforcement activities that can be produced regularly, consistently, accurately, and with minimal resources for the individual Regional Entities and Electric Reliability Organization (ERO) Enterprise.

The final metrics selected are:

- Overall caseload index that quantifies the time it would take to clear violations in inventory based upon historical processing rates;
- Violations in inventory trending over time;
- Violation aging chart that identifies violations in the ERO inventory based upon discovery year;
- Completed mitigation duration chart; and
- Violation aging by disposition method (FFT/SNOP/NOP).

Future initiatives may discuss enhancements or additions to this initial set of metrics.

Once the final metrics were agreed upon, a set of common parameters was developed to ensure that metric measurements by NERC and the Regional Entities remained consistent. Parameters requiring common agreement included violation start date, dismissal date, and violations active and in inventory among the Regional Entities and NERC.

From these common parameters and using current compliance data, NERC and the Regional Entities are in the process of developing metric examples and presentation format. NERC staff expects that this process will be completed in the second quarter of 2013. Once the presentation format and examples have been agreed upon by NERC Enforcement staff and the Regional Entities, the newly proposed metrics will be presented to the Committee for approval. Once approved by the Committee, the metrics will be computed and updated going forward.

Agenda Item 5
Compliance Committee Meeting
February 6, 2013

Compliance Enforcement Initiative (Find, Fix, Track, and Report) Filing

Action
Informational

Background
On September 30, 2011, North American Electric Reliability Corporation (NERC) made its initial Compliance Enforcement Initiative (CEI) filing, which introduced changes to its compliance and enforcement program. The Federal Energy Regulatory Commission (FERC or Commission) issued an order on March 15, 2012 accepting, with 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 (March 15 Order). NERC made its six-month status report in May 2012, accompanied by a compliance filing explaining how NERC considered compliance history in its FFT determinations and its plans for future improvements to the FFT processes. In October 2012, NERC filed the associated training materials. NERC is currently working on an additional informational report to be filed with FERC in March 2013. The report will address specific items of interest raised by FERC in the March 15 Order and may include proposed enhancements to the program. The report will be shared with the Committee prior to the filing.

Summary
NERC continues to process violations through the streamlined Spreadsheet Notice of Penalty (SNOP) and the FFT informational filing. NERC has made monthly SNOP filings and FFT filings with FERC since September 2011. The Commission has issued orders of no further review on the SNOP and Notice of Penalty (NOP) filings submitted through the end of December 2012.[1] Through the end of December 2012, NERC has filed a total of 989 possible violations as FFT remediated issues.

The March 15 Order requires NERC to file a 12-month status report in March 2013. NERC is working with the Regions and Trade Associations to collect the information required for the 12-month status report. The Commission will be evaluating the consistency and application of the FFT initiative and will review the effectiveness of the FFT program with regard to such matters as:

1. The effect of the program on improving Bulk Power System (BPS) reliability;
2. The effect of the program on addressing NERC's compliance and enforcement program, including its caseload;
3. The effect of the program on NERC and the Regional Entities better focusing resources on addressing more serious violations;
4. How NERC's evaluation of risk in identifying candidate Possible Violations for FFT treatment has evolved during the implementation of the FFT initiative, including but not limited to how the violation risk factors have been considered in the evaluation;

[1] Action on the January 31, 2013 filing is expected by March 2, 2013.

5. Manners in which the FFT mechanism can be improved based on experience to date;
6. The results of any audits, spot checks or random samplings that NERC or the Regional Entities may have performed during the year with regard to implementation of the FFT proposal; and
7. The impact, if any, the implementation of the FFT mechanism has had on the number of self-reports submitted.

In the 12-month status report, NERC will also report on results of its evaluation of the consistency and application of the FFT initiative. NERC Enforcement has administered an industry survey to gather registered entity input on the topics of which the Commission seeks information in the 12-month status report filing. NERC Enforcement has reached out to the Trades and Industry Forums requesting registered entity feedback on their experiences in the areas of which FERC is seeking information in the 12-month status report.

Upon review of this 12-month status report, the Commission may consider any necessary changes going forward, including expanding the scope and parameters of possible violations to be processed by FFT informational filings.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda Item 4
Compliance Committee Meeting
February 6, 2013

Quarterly Report on Performance Metrics

Sonia Mendonca, Assistant General Counsel and Director of Enforcement
Compliance Committee Meeting
February 6, 2013

RELIABILITY | ACCOUNTABILITY

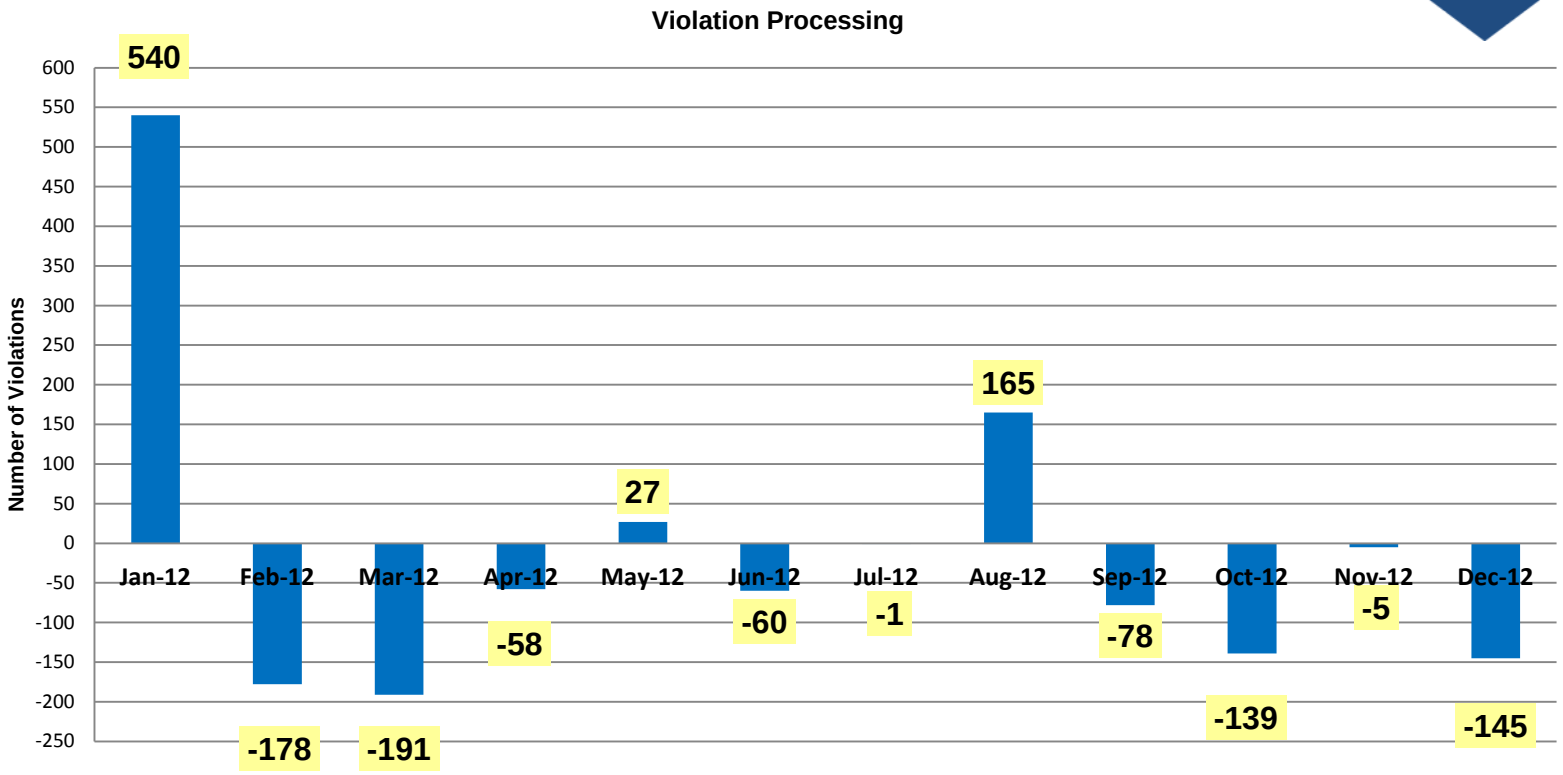





Overview

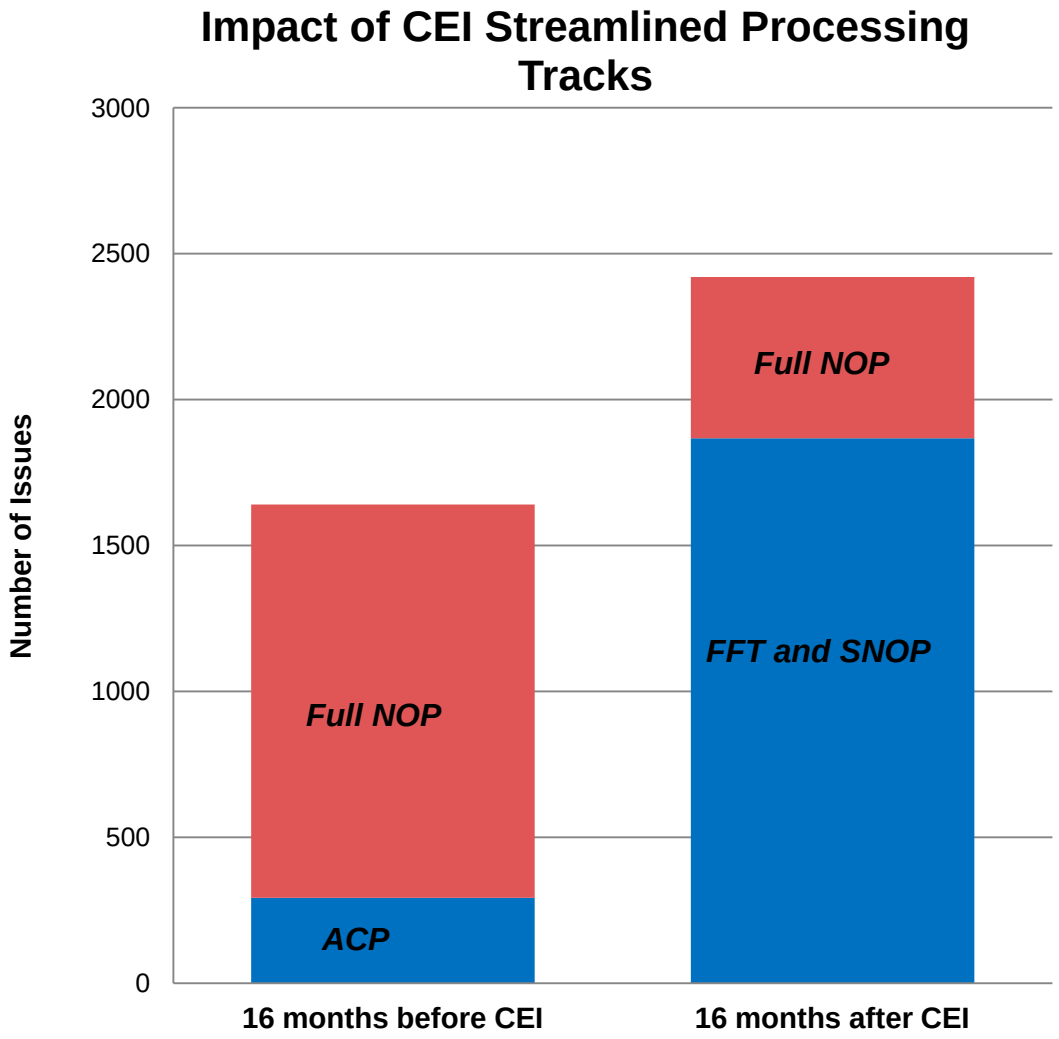
- The ERO reduced its caseload in 2012
- The Compliance Enforcement Initiative (CEI) has positively affected processing
- Eighty percent reduction in violations older than two years
- Older and higher-risk violations remain in focus

Progress in Violation Processing



		For the Year 2012	End of year 2011
New		2569	2944
Dismissed		924	962
Filed		1768	1695
Total Dismissed and Filed		2692	2657
Violation Processing		-123	287

Processing Before and After CEI

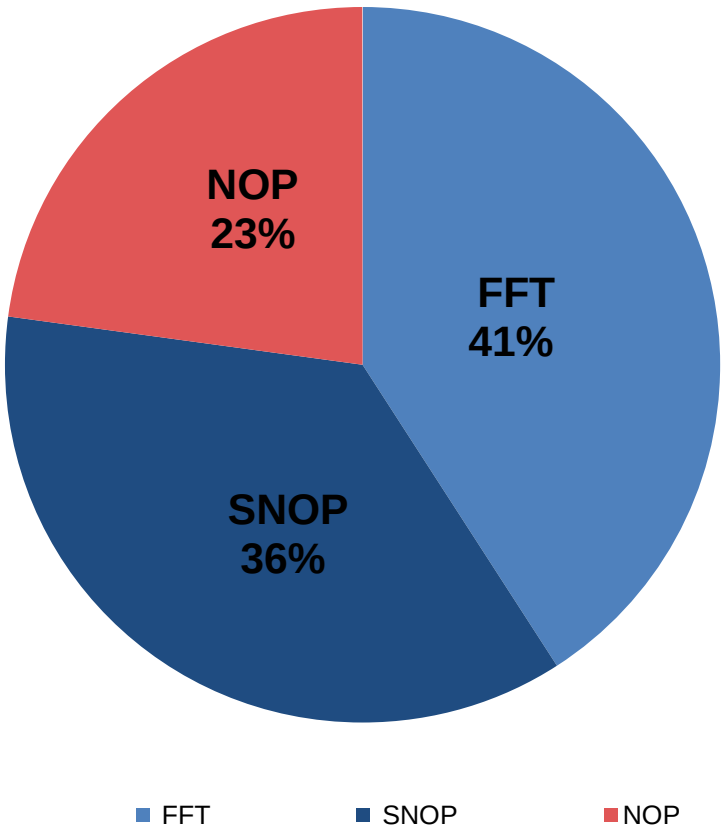


Pre-CEI Monthly Average: **91**

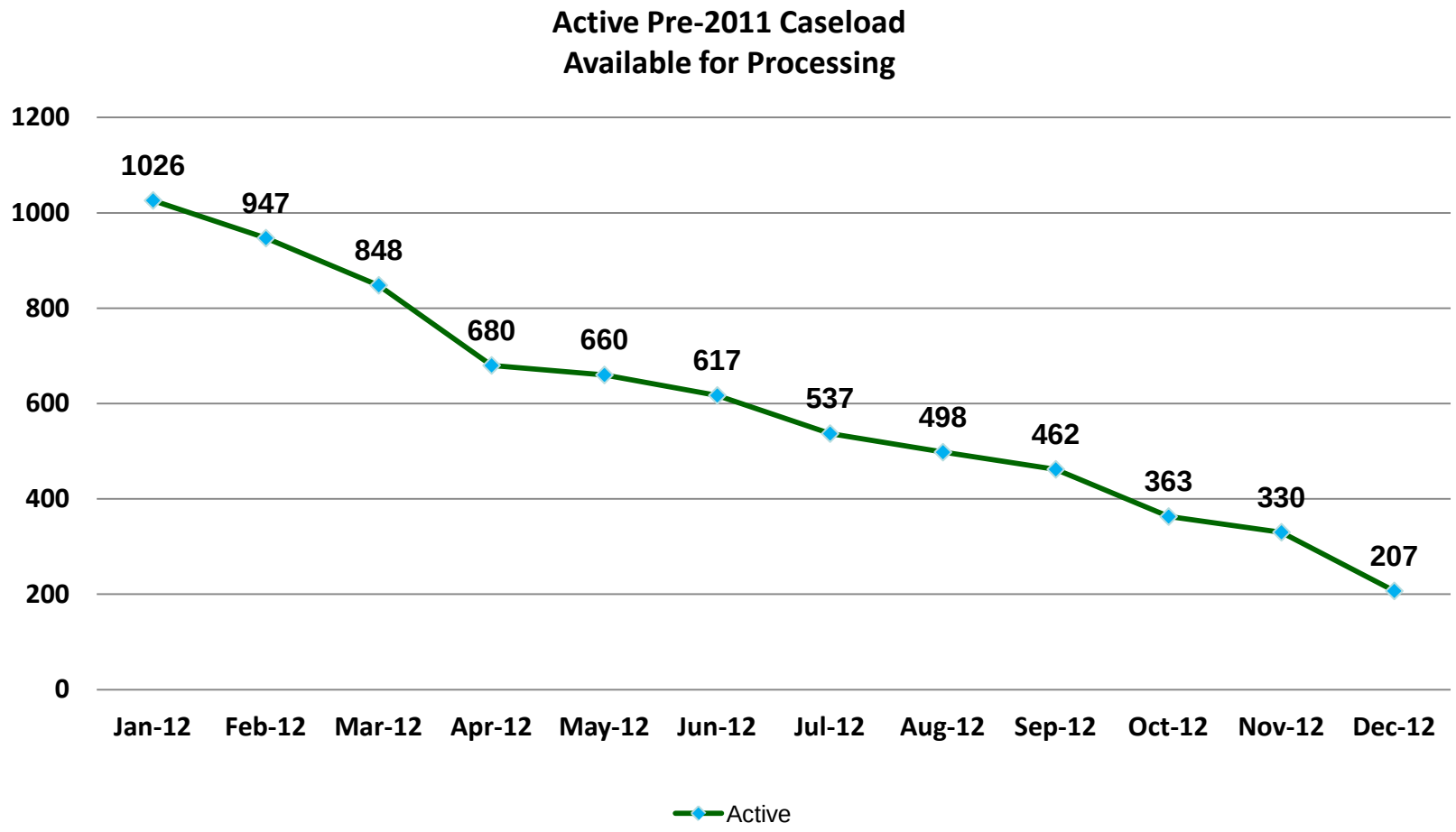
Post- CEI Monthly Average: **151**

Use of Streamlined Processing Tracks

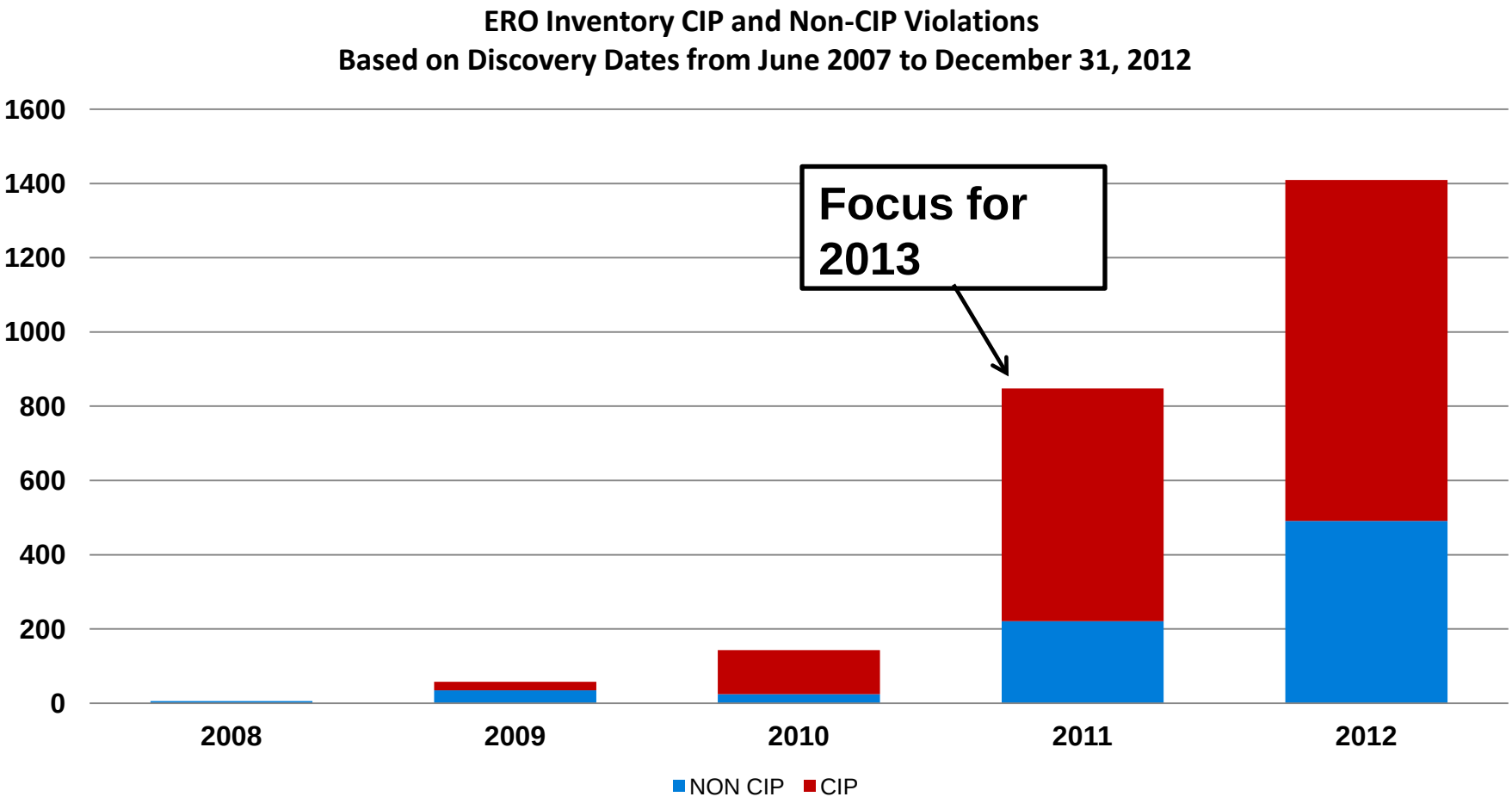
Since September 2011



80% Reduction in Pre-2011 Case Load

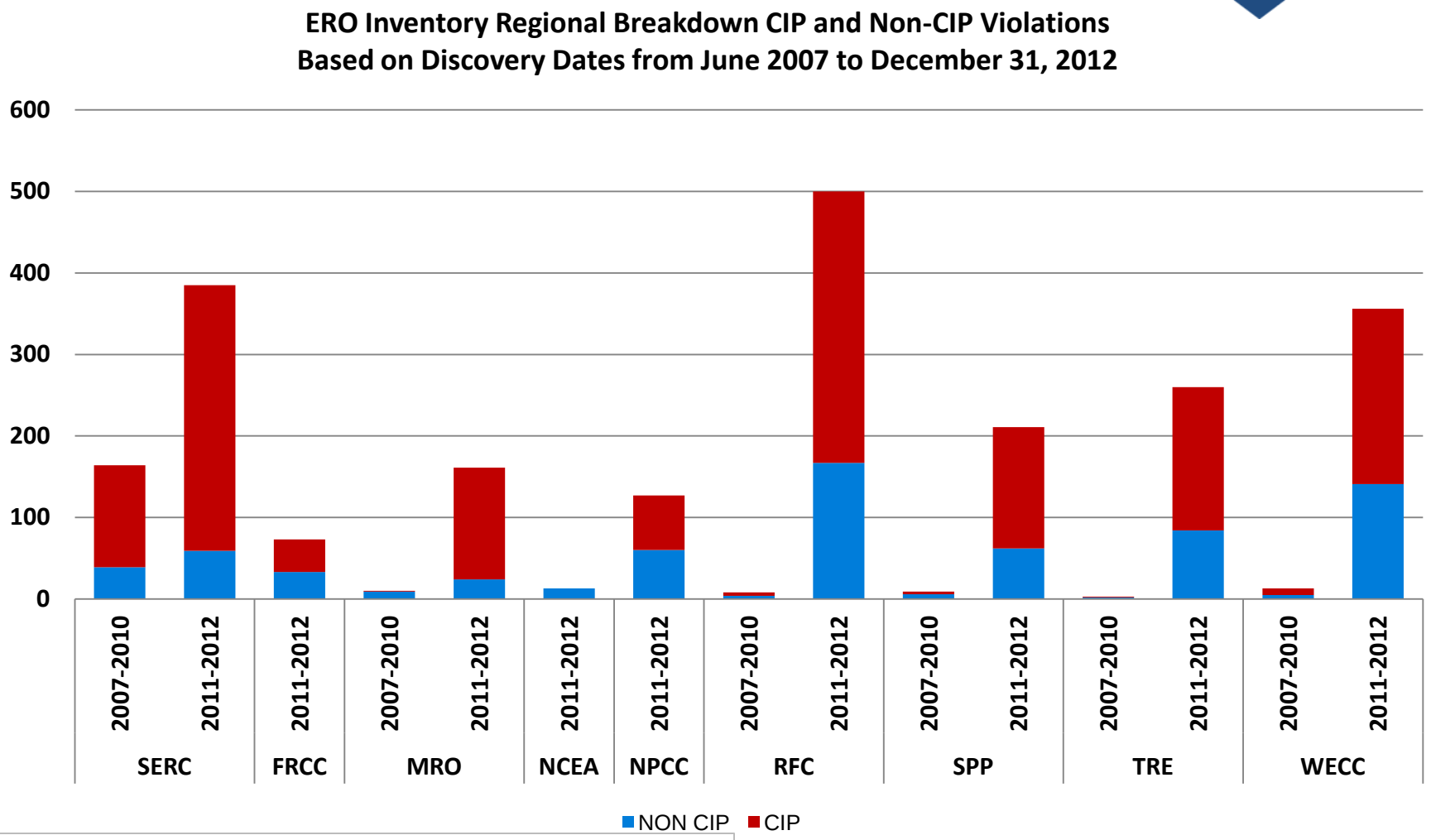


What Remains



*** Reflects Violations for Federal Entities Being Processed**
Excludes Canadian Violations

Where the Violations are by Region



*** Reflects Violations for Federal Entities Being Processed**
Excludes Canadian Violations

Next Steps

- Continue to reduce caseload
- Improve metrics to highlight positive effects of enforcement on reliability



Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda Item 5
Compliance Committee Meeting
February 6, 2013

Compliance Enforcement Initiative

Sonia Mendonca, Assistant General Counsel and Director of Enforcement
Compliance Committee Meeting
February 6, 2013

RELIABILITY | ACCOUNTABILITY

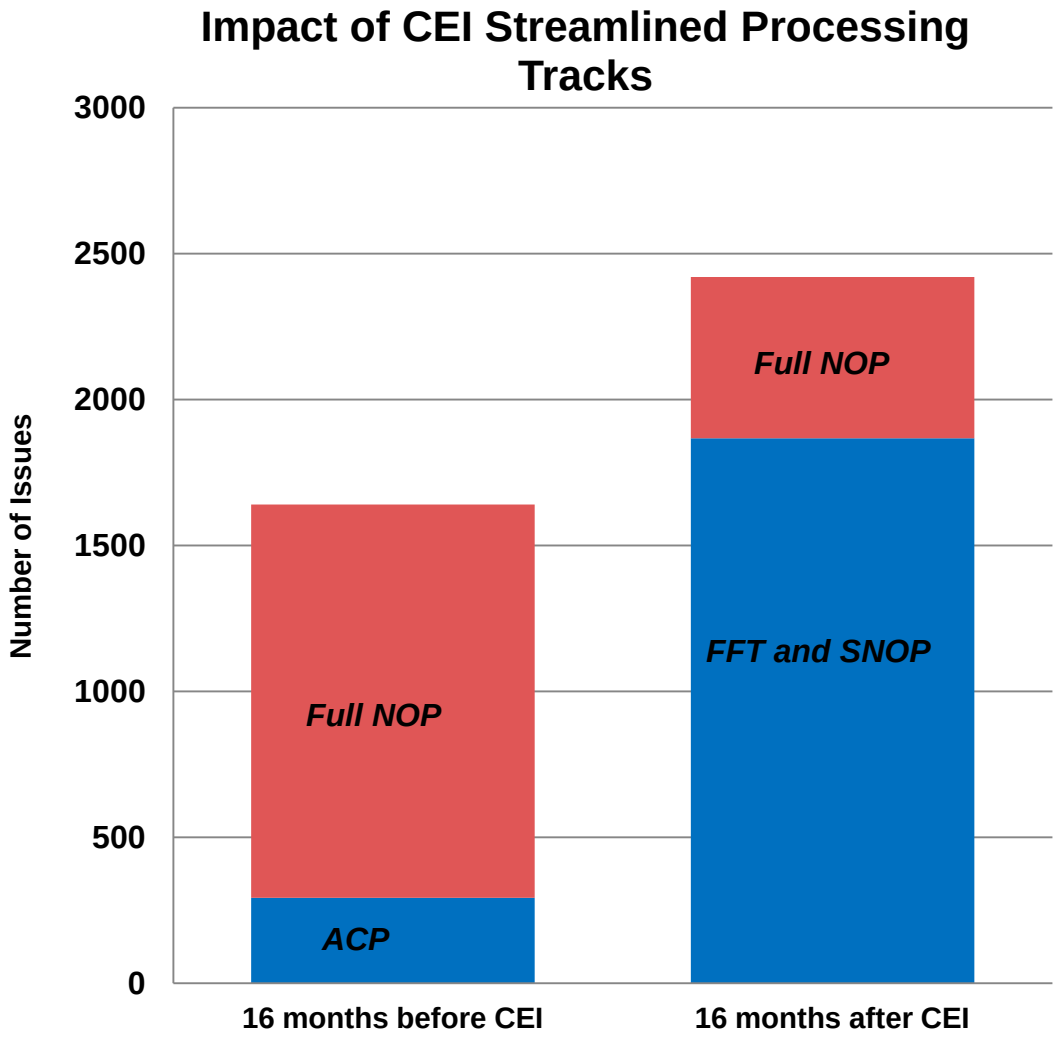





Overview

- Compliance Enforcement Initiative (CEI) benefits:
  - Processing improvements
  - Reliability
  - Allocation of ERO and stakeholder time and resources
- One-year report to FERC on CEI

Processing Before and After CEI

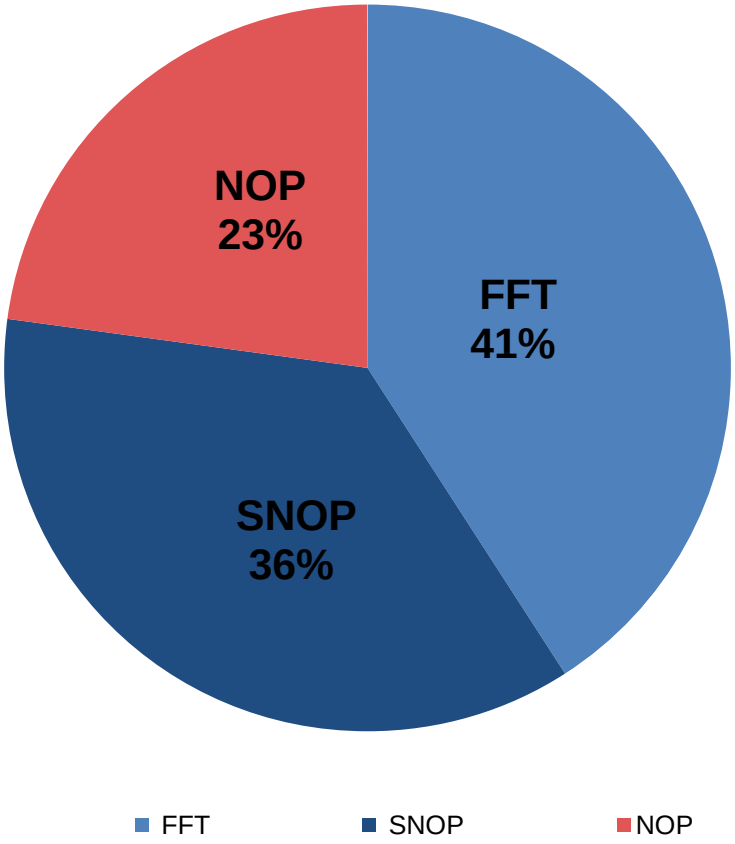


Pre-CEI Monthly Average: **91**

Post- CEI Monthly Average: **151**

Use of Streamlined Processing Tracks

Since September 2011



Reliability Benefits of CEI

- A more risk-based approach to enforcement
- CEI's more streamlined approach allows for enhanced focus on higher-risk issues by the ERO and registered entities
- There is general consensus within industry on the benefits of CEI, with a recent survey showing:
  - Greater willingness to self-monitor and self-report
  - Improved compliance culture

Maximizing CEI

- Evaluating experience thus far
  - Monitoring consistency of implementation across the ERO
    - Pre-filing review of FFTs
    - FFT sampling
- Identifying improvements going forward
  - Incorporating enhancements to bring additional benefits
    - Simpler tracking and reporting requirements
    - Earlier identification of FFTs
    - Streamlined documentation of mitigation

One-Year Report to FERC on CEI

- Benefits of CEI
- Effect on caseload
- Focus on higher-risk reliability matters
- Evaluation of risk
- Proposed improvements
- Monitoring of implementation and overall consistency
- Impact on self-reporting
- Due on March 15, 2013, one year after CEI Order



Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Board of Trustees

February 7, 2013 | 8:00 a.m.-Noon Pacific

Hotel del Coronado
1500 Orange Avenue
Coronado, CA 92118
800-468-3533

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement

Consent Agenda — Approve

1. **Minutes***
   a. January 30, 2013 Conference Call
   b. December 19, 2012 Conference Call
   c. November 26, 2012 Conference Call
   d. November 7, 2012 Meeting
2. **Committee Membership Appointments***
   a. Personnel Certification Governance Committee Membership
   b. Critical Infrastructure Protection Committee Membership
   c. Planning Committee Membership
   d. Reliability Issues Steering Committee Membership

Regular Agenda

3. **Guest Speaker: Mr. Manuel Alanis, CFE**
4. **Remarks by Commissioner Cheryl LaFleur, FERC**
5. **President's Report**
6. **Election and Appointment of Officers — Approve**
7. **Board of Trustees Self-Assessment Results — Review**
8. **Electric Reliability Organization Enterprise Strategic Plan 2013-2016* — Review**
9. **Standards***
   a. **Proposed Continent-wide Standards for Action**
      i. BAL-003-2 - Frequency Response **— Adopt**

ii. Paragraph 81, Phase I — **Adopt**

iii. TPL Table 1, Footnote b — **Adopt**

iv. Generator Verification — **Adopt**

a. MOD-025-2 - Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

b. MOD-026-1 - Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

c. MOD-027-1 Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

d. PRC-019-1 - Coordination of Generating Unit or Plant Capabilities , Voltage Regulating Controls , and Protection

b. **Proposed Interpretations and Standards Addressing Interpretation Requests for Action**

i. Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee — **Adopt**

ii. Interpretation of CIP-002-3 for Oklahoma Gas and Electric — **Adopt**

c. **Proposed Regional Standards for Action**

i. IRO-006-WECC-2 - Qualified Transfer Path Unscheduled Flow (USF) Relief — **Adopt**

d. **Reports for Action or Information**

i. MRO Regional Standards Development Procedure — **Adopt**

ii. Analysis of TOP in Light of Pacific SW Blackout — **Information**

iii. COM-003-1 - Operating Personnel Communications Protocols – **Information**

10. **Standards Process Reform***

a. Standards Committee Strategic Plan and Work Plan — **Approve**

b. Standards Committee Charter — **Approve**

c. Standard Processes Manual Changes — **Approve**

d. Standards Committee Chair and Vice Chair — **Approve**

e. Status of SPIG Recommendations and Board Resolutions to Standards — **Information**

11. **FERC Audit Update and Implementation — Information**

12. **Reliability Issues Steering Committee (RISC) Recommendations* — Accept**

Committee Reports* (Item 13)

a. Operating Committee

b. Planning Committee

c. Critical Infrastructure Protection Committee

d. Member Representatives Committee
e. Personnel Certification Governance Committee
f. Standards Committee
g. Compliance and Certification Committee
    i. Compliance and Certification 2013 Work Plan **— Accept**
    ii. Compliance and Certification Committee Effectiveness Survey Results **— Review**
h. Electricity Sub-Sector Coordinating Council

Forum and Group Reports* (Item 14)

a. North American Energy Standards Board
b. Regional Entity Management Group
c. North American Transmission Forum
d. North American Generator Forum

Board Committee Reports

15. **Corporate Governance and Human Resources**
    a. Review of 2012 Yearend Corporate Performance Goals
    b. Review of 2013 Corporate Performance Goals
    c. Approval of 2013 Board Committee Assignments
    d. Review of Annual Performance of Company Savings and Investment Plan
16. **Compliance**
17. **Finance and Audit**
    a. Review and Acceptance of Unaudited 2012 Year End Financial Statements
18. **Standards Oversight and Technology**

***Background materials included.**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Antitrust Compliance Guidelines

I. General

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.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Draft Minutes
Board of Trustees

December 19, 2012 | 2:00 p.m. local time
Conference Call

Chair John Q. Anderson convened a duly noticed open meeting by conference call of the Board of Trustees of the North American Electric Reliability Corporation on December 19, 2012 at 2:00 p.m. As required by the bylaws of the Corporation, dial-in listen-only access was provided to members of the Corporation and the public for the meeting. The agenda is attached as **Exhibit A**.

Present during the call were: All Board members being John Q. Anderson, Chair, Vicky Bailey, Paul Barber, Tom Berry, Fred Gorbet, Ken Peterson, Jan Schori, Roy Thilly, Bruce Scherr, Dave Goulding, Janice Case, and Gerry Cauley; NERC staff members Charlie Berardesco, Holly Hawkins, Mark Lauby, Laura Hussey, Mallory Huggins, Herb Schrayshuen, Jessica Bian, and Tina Buzzard; and Mr. Allen Mosher, Standards Committee Chair.

NERC Antitrust Compliance Guidelines

Mr. Berardesco directed the participants' attention to the NERC Antitrust Compliance Guidelines.

Planning Committee Membership Changes

Mr. Schrayshuen requested a deviation from the Planning Committee Charter (allowing both Chair and Vice Chair to represent the same sector) and approve Mr. Benjamin Crisp to continue to serve as Vice Chair of the Planning Committee. Upon motion duly made and seconded, the Board approved the following resolution:

> **RESOLVED**, that the Board hereby approves a deviation of the Planning Committee Charter to allow Benjamin Crisp to continue to serve as Vice Chair of the committee.

Section 1600 Data Request for TADS Quarterly and Key Inventory Collection

Mr. Schrayshuen and Ms. Bian provided an overview of the data request. After discussion, and upon motion duly made and seconded, the following resolution was approved:

> **WHEREAS**, in October 2007, the NERC Board of Trustees approved the collection of Transmission Availability Data System (TADS) Phase I data beginning in calendar year 2008 for elements operated at 200 kV and above.
>
> **WHEREAS,** in October 2008, the NERC Board of Trustees approved the collection of Non-Automatic Outage data (Phase II data) beginning in calendar year 2010.
>
> **WHEREAS,** at its September 18-19, 2012 meeting, the Planning Committee approved a revised TADS data request to be developed pursuant to Section 1600 of the NERC Rules of Procedure.

WHEREAS, the revised data request would require data to be submitted on a quarterly basis rather than an annual basis.

WHEREAS, the revised data request also would require reporting of key element inventory data for individual circuits and circuit miles along with outages associated with those circuits rather than only reporting total applicable element counts and total element circuit miles.

WHEREAS, on October 5, 2012, NERC posted the revised data request for a forty-five day public comment period as required by Section 1600 of NERC's Rules of Procedure.

WHEREAS, in response to the posting, NERC received 27 comments, and each comment submittal was evaluated and answered by the Transmission Availability Data System Working Group.

RESOLVED, that the Board hereby approves the ***Transmission Availability Data System Element Inventory and Quarterly Data Collection*** data request to be issued pursuant to Section 1600 of NERC's Rules of Procedure.

Section 1600 Data Request for BES Element Outages Operated at TADS Less than 200 kV

Ms. Bian provided an overview of the data request. After discussion, and upon motion duly made and seconded, the following resolution was approved:

WHEREAS, in October 2007, the NERC Board of Trustees approved the collection of Transmission Availability Data System (TADS) Phase I data beginning in calendar year 2008 for elements 200 kV and above.

WHEREAS, in October 2008, the NERC Board of Trustees approved the collection of Non-Automatic Outage data (Phase II data) beginning in calendar year 2010.

WHEREAS, at its September 18-19, 2012 meeting, the Planning Committee approved a revised TADS data request to be developed pursuant to Section 1600 of the NERC Rules of Procedure to collect data on the less than 200 kV BES element outage data for sustained automatic outages.

WHEREAS, the revised data request would also require operational data to be collected if the five year assessment in 2015 of non-automatic outages finds that the collection of data relative to the elements operated at 200 kV and above beneficial to support identification of risks to reliability.

WHEREAS, the revised data request also would require reporting of key element inventory data for individual circuits and circuit miles along with outages associated with those circuits rather than only reporting total applicable element counts and total element circuit miles.

WHEREAS, on October 5, 2012, NERC posted the revised data request for a forty-five day public comment period as required by Section 1600 of NERC's Rules of Procedure.

WHEREAS, in response to the posting, NERC received 33 comments, and each comment submittal was evaluated and answered by the Transmission Availability Data System Working Group.

RESOLVED, that the Board hereby approves the ***Transmission Availability Data System Bulk Electric System Outages Operated at TADS Less than 200 kV*** data request to be issued pursuant to Section 1600 of NERC's Rules of Procedure.

Revisions to Outstanding Violation Risk Factors and Violation Severity Levels

Mr. Lauby, Ms. Huggins, and Ms. Hussey provided an overview of the revisions to outstanding violation risk factors (VRFs) and violation severity levels (VSLs). After discussion, and upon motion duly made and seconded, the following resolutions were approved:

WHEREAS, NERC staff have collaborated with FERC staff to review a set of outstanding Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for revision or further justification to reflect the NERC and FERC VRF and VSL Guidelines finalized between 2007 and 2009.

RESOLVED, that the Board hereby adopts the proposed VRF and VSL modifications as presented to the Board at this meeting.

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

Reliability Standards Development Plan (RSDP)

Messrs. Lauby and Mosher provided an overview of the Reliability Standards Development Plan for 2013-2015. Mr. Lauby specifically noted this RSDP is a significant departure from prior year work plans, expediting a number of previously scoped projects and leveraging changes in staffing and process to aggressively complete projects under development and undertake and complete new projects. Subject to the edits and clarifications discussed, and upon motion duly made and seconded, the following resolutions were approved:

RESOLVED, that the Board hereby approves the Reliability Standards Development Plan 2013-2015.

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities for information purposes.

WECC Regional Standard BAL-004-WECC-02 Automatic Time Error Correction

Mr. Lauby provided an overview of the proposed WECC Regional Standard. After discussion, and upon motion duly made and seconded, the following resolutions were approved:

RESOLVED, that the Board hereby adopts the BAL-004-WECC-2—Automatic Time Error Correction and BAL-001-1 Real Power Balancing Control Performance Reliability Standards, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the associated implementation plan, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the Violation Risk Factors and Violation Severity Levels for the proposed BAL-004-WECC-2 and BAL-001-1 Reliability Standards, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby approves the following retirements:

- Reliability Standard BAL-004-WECC-1 – Automatic Time Error Correction (ATEC) (Superseded by BAL-004-WECC-2)
- Reliability Standard BAL-001-0.1a – Real Power Balancing Control Performance and associated Appendix 2 interpretation (Superseded by BAL-001-1)
- Appendix 1 Interpretation of R3 in BAL-003-0.1b – Frequency Response and Bias

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

Adjournment

There being no further business, and upon motion duly made and seconded, the meeting was adjourned at approximately 3:05 p.m. local time.

Submitted by,



Charles A. Berardesco
Secretary

Draft Minutes
Board of Trustees

November 26, 2012 | 2:00 p.m. local time
Conference Call

Chair John Q. Anderson convened a duly noticed open meeting by conference call of the Board of Trustees of the North American Electric Reliability Corporation on November 26, 2012 at 2:00 p.m. Eastern. As required by the bylaws of the Corporation, dial-in listen-only access was provided to members of the Corporation and the public for the meeting. The agenda is attached as **Exhibit A**.

Present during the call were: Board members being John Q. Anderson, Chair, Vicky Bailey, Paul Barber, Tom Berry, Fred Gorbet, Ken Peterson, Jan Schori, Roy Thilly, Bruce Scherr, Dave Goulding, and Gerry Cauley; and NERC staff members Charlie Berardesco, Eric Rollison, Holly Hawkins, Steven Noess, Janet Sena, and Tina Buzzard.

NERC Antitrust Compliance Guidelines
Mr. Berardesco directed the participants' attention to the NERC Antitrust Compliance Guidelines.

Cyber Security, Order 706 (CIP Version 5)
Messrs. Lauby and Noess provided an overview of the proposed CIP Version 5 Reliability Standards and the implementation plan and timeline for those standards. Mr. Lauby stated Version 5 is intended to address all of the remaining standards-related directives from FERC's Order No. 706, introduces an improved format and approach to NERC's CIP Reliability Standards, and will be filed with FERC by the filing deadline of March 31, 2013. Mr. Noess provided an overview of the advancements in CIP Version 5 compared to previous versions, stating Version 5 is a results-based set of standards, a format which allows the standards to focus on reliability and security-related results with less emphasis on specific technologies. After discussion and upon motion duly made and seconded, the Board approved the following resolutions:

RESOLVED, that the Board hereby adopts the following Reliability Standards (collectively, the "CIP Version 5 standards"), as presented to the Board at this meeting:

- CIP-002-5—Cyber Security—BES Cyber System Categorization
- CIP-003-5—Cyber Security—Security Management Controls
- CIP-004-5—Cyber Security—Personnel and Training
- CIP-005-5—Cyber Security—Electronic Security Perimeter(s)
- CIP-006-5—Cyber Security—Physical Security of BES Cyber Systems
- CIP-007-5—Cyber Security—Systems Security Management
- CIP-008-5—Cyber Security—Incident Reporting and Response Planning

- CIP-009-5—Cyber Security—Recovery Plans for BES Cyber Systems
- CIP-010-1—Cyber Security—Configuration Change Management and Vulnerability Assessments
- CIP-011-1—Cyber Security—Information Protection

FURTHER RESOLVED, that the Board hereby adopts the "Definitions of Terms used in Version 5 CIP Cyber Security Standards," which includes all of the CIP Version 5 proposed additions, modifications, and retirements of terms to the *Glossary of Terms used in NERC Reliability Standards*, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the associated implementation plan for the proposed CIP Version 5 standards, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the Violation Risk Factors and Violation Severity Levels for the proposed CIP Version 5 standards, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the following retirements:

> Upon approval of the CIP Version 5 implementation plan, CIP-002-3 through CIP-009-3 are extended and do not retire until the Effective Date of CIP Version 5 in the particular jurisdiction in which the new standards are becoming effective, and CIP-002-4 through CIP-009-4 do not become effective.

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

2012 Long-Term Reliability Assessment

Mr. Moura provided an overview of the draft 2012 Long-Term Reliability Assessment and completed a high level summary noting the report provides an independent, 10-year view of the electricity industry by evaluating key reliability indicators, including peak demand and energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other issues that may impact the reliability of the bulk power system. Mr. Moura reviewed the key findings in the report. At the conclusion of Mr. Moura's summary, Chair Anderson led the Board through a section-by-section discussion of the report. Individual trustees raised questions and suggested clarifying edits and revisions. Following extended discussion, and upon motion duly made and seconded, the Board approved the draft 2012 Long-Term Reliability Assessment for publication, subject to the edits and clarifications discussed during the meeting.

2012/2013 Winter Reliability Assessment

Mr. Moura reviewed the highlights and three key findings of the draft 2012/2013 Winter Reliability Assessment noting the report covers the four-month (December 2012–February 2013) upcoming winter period and provides an overall perspective on the adequacy of the generation resources and transmission systems necessary to meet projected winter peak demands. At the conclusion of Mr.

Moura's summary, Chair Anderson led the Board through a discussion of the report. Individual trustees raised questions and suggested clarifying edits and revisions. Following extended discussion, and upon motion duly made and seconded, the Board approved the draft 2012/2013 Winter Reliability Assessment for publication, subject to the edits and clarifications discussed during the meeting.

Chair Anderson expressed the appreciation of the Board for the outstanding work of the Reliability Assessment Subcommittee and NERC staff in developing both reports.

Gaining Efficiencies in the Seasonal Reliability Assessment Approval Process

Mr. Moura reviewed recommended options by NERC Management in gaining efficiencies in the seasonal reliability assessment approval process. Mr. Moura stated the first option would be for the Board to delegate approval authority of the Summer and Winter Reliability Assessments to the NERC Technical Committees (i.e., Planning and/or Operating Committees) for publication. This delegated authority would allow NERC staff to publish the assessments without formal Board approval, thereby resulting in reports being published about two weeks in advanced of current timelines. Board approval of the annual Long-Term Reliability Assessment and any Special Assessments would still be required. The second option, would be for NERC Management to continue with the current process (seeking Board approval) and deliver a more concise summary of the report (i.e., 20 pages) allowing a more efficient review by the Board. After discussion, the Board determined option two was preferred and requested NERC Management work to streamline both the reports and current production timelines.

Adjournment

There being no further business, and upon motion duly made and seconded, the meeting was adjourned at approximately 3:35 p.m. local time.

Submitted by,



Charles A. Berardesco
Secretary

Draft Minutes
Board of Trustees

November 7, 2012 | 8:00 a.m. local time

JW Marriott New Orleans
614 Canal Street
New Orleans, LA 70130
504-525-6500

Chair John Q. Anderson called to order a duly noticed meeting of the North American Electric Reliability Corporation Board of Trustees on May 9, 2012 at 8 a.m., local time, and a quorum was declared present. The Agenda is attached as **Exhibit A.**

Present at the meeting were: All Board members, being John Q. Anderson, Chair, Janice Case, Vicky Bailey, Tom Berry, Jan Schori, Paul Barber, Roy Thilly, Fred Gorbet, Dave Goulding, Bruce Scherr, Ken Peterson, and Gerry Cauley.

A listing of attendees is attached as **Exhibit B.**

Mr. Anderson began the meeting by honoring outgoing NERC Senior Vice President Dave Nevius with a resolution from the Board recognizing his years of service and outstanding contributions to NERC. While Mr. Nevius will step down as Senior Vice President effective December 31, he will remain at NERC in a consultant role through August 31, 2013.

NERC Antitrust Compliance Guidelines

Mr. Berardesco, senior vice president and general counsel, directed participants' attention to the NERC Antitrust Compliance Guidelines included in the agenda.

Executive Session

Mr. Anderson reported that before the open meeting, as is its custom, the Board met in closed session with Management and then in executive session without Management, to review management activities.

Consent Agenda

Upon motion duly made and seconded, the Board approved the consent agenda, as follows:

Minutes

The Board approved the following draft minutes:

a. August 16, 2012

Committee Membership Appointments and Charter Changes

Upon motion duly made and seconded, the Board approved the proposed nominations to the membership of the Personnel Certification Governance Committee Membership and Critical Infrastructure Protection Committee Membership, attached hereto as **Exhibit C**.

Future Meetings
Mr. Cauley made note of the change in location from Philadelphia, PA to Boston, MA for the May 9, 2013 Board meeting.

Welcoming Remarks by Rod West, Entergy

Mr. West welcomed the audience to his home city and provided an overview of recent storms affecting New Orleans and surrounding areas and Entergy's response in restoring services and lessons learned from the different storms' impacts. Mr. West highlighted best practices and next steps established by Entergy in response to the lessons learned.

Remarks by Commissioner LaFleur

In her opening remarks, Commissioner LaFleur addressed the Geomagnetic Disturbance Notice of Proposed Rulemaking, which directs NERC to create two new standards. Ms. LaFleur stated it is a significant, challenging order but the creation of the new standards is important to the reliability of the bulk power system. Concluding, Ms. LaFleur addressed the Standards Reform and Compliance Reform initiatives stating she is encouraged by what she has heard and looks forward to continued progress.

Remarks by Mike Bardee, Director of OER and Joe McClelland, Director of OEIS

Messrs. Bardee and McClelland provided an overview of their new roles within FERC, as well as addressed questions from Board members.

President's Remarks

Mr. Cauley's remarks provided an overview of the past year highlighting items such as the FERC Audit, the improved budget and business planning process, and the Section 215 criteria development. Looking forward, Mr. Cauley stated the ERO should continue its focus on establishing the right goals with the most impact to reliability, as well as continue to focus on and address the challenges in standards and compliance through the Standards Reform and Compliance Reform initiatives.

Concluding his report, Mr. Cauley thanked MRC Chair Scott Helyer for his leadership and excellent working relationship over the past year.

Standards

Mr. Lauby, vice president of standards and training, provided an overview of the Reliability Standards Program and presented the following items for Board action. After discussion, and upon motion duly made and seconded, the following resolutions were approved:

COM-001-2—Communications

RESOLVED, that the Board hereby adopts the COM-001-2 – Communications Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the definitions for Interpersonal Communication and Alternative Interpersonal Communication to be added to the NERC Glossary of Terms upon approval, as presented to the Board at this meeting:

FURTHER RESOLVED, that the Board hereby adopts the associated implementation plan for the proposed standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the Violation Risk Factors and Violation Severity Levels for the proposed COM-001-2 Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the corresponding retirement of the COM-001-1.1—Telecommunications Reliability Standard, Requirements R1, R2, R3, R5, and R6 at midnight on the day immediately prior to the effective date of COM-001-2.

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

COM-002-3—Communication and Coordination

RESOLVED, that the Board hereby adopts the COM-002-3 – Communication and Coordination Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the associated implementation plan, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the Violation Risk Factors and Violation Severity Levels for the proposed COM-002-3 Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the corresponding retirement of the COM-002-2a—Communications and Coordination Reliability Standard at midnight on the day immediately prior to the effective date of COM-002-3 in the particular jurisdiction in which the new standard is becoming effective.

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

PRC-005-2—Protection System Maintenance

RESOLVED, that the Board hereby adopts the PRC-005-2—Protection System Maintenance Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the associated implementation plan, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the Violation Risk Factors and Violation Severity Levels for the proposed PRC-005-2 Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the corresponding retirement of the following standards at midnight of the day immediately prior to the first day of the first calendar quarter that commences one hundred fifty-six (156) months following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, at midnight on the day immediately prior to the first day of the first calendar quarter that commences one hundred sixty-eight (168) months following adoption by the NERC Board of Trustees:

- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding (UFLS) Equipment Maintenance Program
- PRC-011-0 – Undervoltage Load Shedding (UVLS) System Maintenance and Testing
- PRC-017-0 – Special Protection System (SPS) Maintenance and Testing

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

EOP-004-2—Event Reporting

RESOLVED, that the Board hereby adopts the EOP-004-2 – Event Reporting Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the associated implementation plan, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the Violation Risk Factors and Violation Severity Levels for the proposed EOP-004-2 Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the corresponding retirement of the following standards at midnight on the day immediately prior to the effective date of EOP-004-2:

- EOP-004-1 – Disturbance Reporting
- CIP-001-2a – Sabotage Reporting

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

Rapid Revision of TOP-006-2—Monitoring System Conditions

RESOLVED, that the Board hereby adopts the TOP-006-3 –Monitoring System Conditions Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the associated implementation plan, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the Violation Risk Factors and Violation Severity Levels for the proposed TOP-006-3 Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the corresponding retirement of the TOP-006-2 Reliability Standard at midnight the day immediately prior to the effective date of TOP-006-3.

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

Interpretation of R4 and R5 of BAL-002-0—Disturbance Control Performance

RESOLVED, that the Board hereby adopts the proposed Interpretation of Requirements R4 and R5 of BAL-002-0—Disturbance Control Performance Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

PRC-006-SPP-01—SPP Automatic Underfrequency Load Shedding

RESOLVED, that the Board hereby adopts the PRC-006-SPP-01—Automatic Underfrequency Load Shedding Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the associated implementation plan, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the Violation Risk Factors and Violation Severity Levels for the proposed PRC-006-SPP-01 Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

BAL-002-WECC-2—Contingency Reserve

RESOLVED, that the Board hereby adopts the BAL-002-WECC-2—Contingency Reserve Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the associated implementation plan, as presented to the Board at this meeting.

FURTHER RESOLVED, that the Board hereby adopts the Violation Risk Factors and Violation Severity Levels for the proposed BAL-002-WECC-2 Reliability Standard, as presented to the Board at this meeting.

FURTHER RESOLVED, that NERC management is hereby authorized and directed to make the appropriate filings with ERO governmental authorities.

Withdraw Approval of MOD-025-RFC-01—Verification and Data Reporting of Generator Gross and Net Reactive Power Capability

WHEREAS, the Board approved the proposed Reliabilty*First* MOD-025-RFC-01—Verification and Data Reporting of Generator Gross and Net Reactive Power Capability Reliability Standard on November 3, 2011.

WHEREAS, after Board approval, Reliability*First* staff noted the associated draft NERC standard (MOD-025-2) is designated as a high priority standard and is actively being developed.

WHEREAS, Reliability*First* staff also noted that the Reliability*First* MOD-025-RFC-01 standard does not go beyond or add detail to what the associated draft NERC standard is proposing and, from a reliability standpoint, the intent of both standards is the same.

WHEREAS, Reliability*First* staff determined there is no requirement for the proposed regional standard in the Reliability*First* region and has requested that the Board rescind its approval of MOD-025-RFC-01 Reliability Standard.

NOW, THEREFORE, BE IT RESOLVED, that the Board rescinds approval of the MOD-025-RFC-01 Reliability Standard that was previously approved by the Board on November 3, 2011.

Improvements to the Reliability Standards Development Process

WHEREAS, the Electric Reliability Organization (ERO) is responsible for the development of a body of clear, high quality technically excellent Reliability Standards that are needed to ensure the reliable operation and planning of the bulk power system.

WHEREAS, the NERC Board is responsible for establishing strategic priorities for NERC, including ensuring that this responsibility is carried out in a timely and efficient manner that meets regulatory obligations.

WHEREAS, the ERO relies on the technical expertise and commitment of industry volunteers to develop technically excellent Reliability Standards based on the principles of an ANSI-accredited standards development process to ensure industry consensus in support of these standards.

WHEREAS, the ERO relies upon and has delegated responsibility to oversee and manage the standards development process to the Standards Committee, and the Standards Committee appoints the standard drafting teams that are charged with executing these responsibilities.

WHEREAS, NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America.

WHEREAS, the Standards Committee and standard development teams should be accountable to the Board for developing and maintaining high quality standards in a timely manner and further enabling the ERO to respond to reliability priorities.

WHEREAS, on May 9, 2012, the Board endorsed the recommendations of the Standards Process Input Group for improving the effectiveness and efficiency of the NERC standards development process.

WHEREAS, the institution of the Reliability Issues Steering Committee was approved as a Standards Process Input Group recommendation by the Board to advise the Board on prioritization and dispensation of Reliability Standards efforts.

WHEREAS, in response to these recommendations, the Standards Committee developed proposed revisions to the Standard Processes Manual, which is set forth as Appendix 3A to the NERC Rules of Procedure, that are expected to be presented to the Board for approval in February 2013.

WHEREAS, NERC, the Regional Entities, and stakeholders are nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards have become necessary.

WHEREAS, NERC and the Standards Committee have determined that establishing a body of high-quality Reliability Standards will require dispensing of work that is no longer pertinent to reliability, and aggressively pursuing work that will result in a body of high-quality Reliability Standards that will address reliability risks to the bulk power system.

WHEREAS, the ERO is in full accord with industry stakeholders that fundamental changes to the NERC compliance and enforcement process are required to ensure that perceived enforcement risks do not have an adverse impact on the development of high quality Reliability Standards.

WHEREAS, NERC management has committed to make available the NERC resources and processes needed to execute this plan.

NOW, THEREFORE, BE IT RESOLVED, that the ERO must move forward to develop a body of high-quality results-based standards.

FURTHER RESOLVED, that the Standards Committee and standard development teams should be accountable to the Board while developing and maintaining high-quality Reliability Standards in a timely manner and further enabling the ERO to respond to reliability priorities, and the Standards Committee shall modify its governance, structure and scope to enable such accountability.

FURTHER RESOLVED, that standard drafting teams should be staffed with a small number of subject matter experts that includes competencies in technical, legal, drafting, compliance, and project management.

FURTHER RESOLVED, that the Standards Committee should manage workflow and process to ensure the timely development of high-quality, results-based Reliability Standards.

FURTHER RESOLVED, that the Standards Committee and NERC staff should work with the Reliability Issues Steering Committee to jointly develop viable work plans to dispense with work that is no longer pertinent to reliability and aggressively pursue work that will result in a body of high-quality Reliability Standards that will address reliability risks to the bulk power system.

FURTHER RESOLVED, that the Standards Committee and NERC staff is hereby directed to report back to the Board at the February 2013 meeting on the status of these directives.

Amendments to Delegation Agreement with Reliability*First* Corporation (RFC) – Amended Exhibit B (RFC Bylaws)

Ms. Michael, associate general counsel, provided an overview and presented for Board action the amendments to the Delegation Agreement with Reliability*First* Corporation (RFC), reflecting amendments to RFC's Bylaws. After discussion, and upon motion duly made and seconded, the following resolution was approved:

RESOLVED, that the Board hereby approves the proposed amendments to NERC's Delegation Agreement with RFC, consisting of amended RFC Bylaws (Exhibit B to Delegation Agreement), as presented to the Board at this meeting.

2012 Frequency Response Initiative Report

Mr. Cummings, director of reliability initiatives and system analysis, provided an overview and presented for Board action the 2012 Frequency Response Initiative Report. After discussion, and upon motion duly made and seconded, the following resolution was approved:

RESOLVED, that the Board hereby accepts the 2012 Frequency Response Initiative Report, as presented to the Board at this meeting.

Critical Infrastructure Update

Mr. Blizard, director of critical infrastructure, provided an overview of recent critical infrastructure protection (CIP) activities. Mr. Blizard stated the 2nd annual Grid Security Conference (GridSecCon) took place on October 16-18, 2012 in San Diego, attracting over 250 attendees from industry, government, and academia. The conference included the SANS Institute, Idaho National Labs, and Lofty Perch providing cybersecurity training to over 100 attendees, as well as expert speakers from industry

and government addressing threats and security lessons learned. Mr. Blizard noted the 2013 Grid Security Exercise (GridEx) will take place on November 13-14, 2013. The GridEx planning cycle will take place in the fourth quarter 2012. The 2013 exercise will focus on a coordinated physical and cyber threat scenario with more focus being given to physical security. The Critical Infrastructure Protection Committee (CIPC) has started to take nominations for the GridEx Working Group and the working group will be officially formed at the December 2012 CIPC meeting.

Concluding, Mr. Blizard stated the Critical Infrastructure Department will more closely examine the Electricity Sub-sector Cybersecurity Risk Management Process guideline and examine Sacramento Municipal Utility District and their implementation of the guideline and its impact on risk, security, and CIP compliance. This initiative will take place in the fourth quarter 2012 resulting in a final report to industry.

Mr. Tim Roxey, chief cyber security officer, summarized the ES-ISAC's key activities and provided a review of the ES-ISAC's 2012 goals. In addition, Mr. Roxey stated the ES-ISAC continues to enhance the capability of its two primary functions: information sharing and information analysis. Concluding his report, Mr. Roxey stated the ES-ISAC has written two alerts and held a large Multi-Sector Webinar, noting more webinars and updates to the ES-ISAC portal are upcoming.

Standing Committee Reports

The Standing Committees Chairs provided reports to the Board highlighting items from their written reports as contained in the Agenda package. Mr. Anderson welcomed Ms. Chris Schwab, Reliability Issues Steering Committee Chair to her first Board meeting and presentation of her first report to the Board.

Forum and Group Reports

Regional Entity Management Group

Mr. Gallagher highlighted recent activities of the key multi-Regional groups, noting detailed summaries were contained in the full written report to Board.

North American Transmission Forum

Mr. Galloway referred to the Forum's written report to the Board. Mr. Galloway stated the Forum continues to focal on important reliability topics to include geomagnetic disturbance, facility rating alert follow-up and event follow-up such as the September 8, 2011 and Cold Snap events.

Board Committee Reports

Corporate Governance and Human Resources

Ms. Case, chair, provided a summary of the Corporate Governance and Human Resources Committee (CGHRC) open and closed meetings occurring via conference call on October 29, 2012. Ms. Case requested Board approval of the Finance and Audit and Standards Oversight and Technology Committees' mandates. Upon motion duly made and seconded, the Board approved the following resolutions:

RESOLVED, that the Board hereby approves the proposed amendments to the Finance and Audit Committee mandate, as presented to the Board at this meeting.

RESOLVED, that the Board hereby approves the proposed amendments to the Standards Oversight and Technology Committee Mandate in the form presented to the Board at this meeting.

Compliance Committee

Mr. Scherr, chair, provided a summary of the Committee's open meeting from the previous day, highlighting the update provided by NERC staff on the Compliance Enforcement Initiative, including the Find, Fix, and Track and Report (FFT), and an update on the filing of the 12-month FFT compliance report. In addition, Mr. Scherr reviewed the status of the Compliance Enforcement Initiative White Papers, highlighting the discussion held during the Member Representatives Committee meeting. Mr. Scherr also referenced the presentation offered by Mr. Dan Skaar, CEO of MRO, on the improvements to Regional audit practices.

Finance and Audit Committee

Mr. Gorbet, chair, provided a summary of the Committee's open meeting held via conference call on October 31, 2012. In addition, Mr. Gorbet provided an overview of the meeting of the Risk Management and Internal Controls Subcommittee on November 5, 2012.

Mr. Gorbet reviewed the third quarter Statement of Activities and Yearend Forecasts. Upon motion duly made and seconded, the Board approved the following resolution:

RESOLVED, that the Board hereby accepts the NERC Third Quarter 2012 Statement of Activities and Year-end Forecasts, as presented to the Board at this meeting.

Mr. Gorbet reviewed NERC Management's request to exercise an option for additional office space in the Atlanta Financial Center. After discussion, and upon motion duly made and seconded, the Board approved the following resolution:

WHEREAS, NERC is party to a Lease Agreement dated November 3, 2010, as amended to date, (the Lease) for certain premises in Atlanta, Georgia for its corporate headquarters and other operations.

WHEREAS, management and the Finance and Audit Committee have recommended that NERC exercise an option (the Option) to expand its premises, as set forth in the Lease, on substantially the terms and conditions presented to the Board at this meeting, subject to the approval by the Federal Energy Regulatory Commission of NERC's 2013 Business Plan and Budget which includes the projected additional rent expense.

NOW, THEREFORE, BE IT RESOLVED, that the Board hereby approves the exercise of the Option and authorizes the execution of appropriate agreements related thereto, on substantially the terms and conditions presented to the Board at this meeting, subject to the approval by the Federal Energy Regulatory Commission of NERC's 2013 Business Plan and Budget which includes the projected additional rent expense.

Nominating Committee
Ms. Schori, chair, reported the Committee met in closed session on November 5, 2012 and selected a slate of finalists for interviews for the vacancies on the Board. The Nominating Committee Interview Panel will conduct the interviews in Dallas, TX at the end of November. Final candidates for election to the Board will be presented to the full Nominating Committee in December for approval and recommendation to the Member Representatives Committee.

Standards Oversight and Technology Committee
Mr. Peterson, chair, provided a summary of the Committee's open meeting the day prior, noting the discussion on the reorganization of NERC's Standards Department and other steps being taken to enhance overall production of high-quality standards. Mr. Peterson reviewed the efforts of NERC's Information Technology department in finalizing the move of applications from NERC's previous headquarters in Princeton, NJ to Atlanta, GA.

Closing

Mr. Anderson requested any final comment from Commissioner LaFleur. Commissioner LaFleur commended the discussions during the meetings and the continued focus on the standards and compliance initiatives.

Chair Anderson agreed the discussions were valuable and thanked the industry for their attendance and continued support. In addition, Chair Anderson thanked MRC Chair Helyer for his leadership over the past year and on behalf of the Board looked forward to working with incoming MRC Chair Carol Chinn.

Adjournment

There being no further business, and upon motion duly made and seconded, the meeting was adjourned at 11:45 a.m. local time.

Submitted by,



Charles A. Berardesco
Secretary

Agenda Item 2a
Board of Trustees Meeting
February 7, 2013

Personnel Certification Governance Committee Membership

Action

Due to the transition of the Vice Chair to Chair, the Board of Trustees is asked to approve:

- The appointment of Mike Anderson, American Electric Power, as Vice Chair of the Personnel Certification Governance Committee replacing Brett Hallborg for a term ending November 30, 2014.

Agenda Item 2b
Board of Trustees Meeting
February 7, 2013

Critical Infrastructure Protection Committee Membership

Action

Due to recent replacement designations by the Regions of representation to the Critical Infrastructure Protection Committee, the Board of Trustees is asked to approve:

- The appointment of Darrell Klimitchek from South Texas Electric Cooperative (STEC) to the Critical Infrastructure Protection Committee replacing James Grimshaw for the term 2012-2014.
- The appointment of Mike Mertz from Public Service Company of New Mexico (PNM) to the Critical Infrastructure Protection Committee replacing Robert Mathews for the term 2012-2014.

Agenda Item 2c
Board of Trustees Meeting
February 7, 2013

Planning Committee Membership

Action

The Board of Trustees is asked to approve:

- The appointment of J. Feit, Public Service Commission of Wisconsin, State Government to the Planning Committee for the term 2012-2014.

Agenda Item 2d
Board of Trustees Meeting
February 7, 2013

Reliability Issues Steering Committee Membership

Action

The Board of Trustees is asked to approve:

- The appointment of Brian J. Murphy, Next Era Energy, to replace Allen Mosher, to the Reliability Issues Steering Committee for the term for which Mr. Mosher was nominated.

Draft
Electric Reliability Organization Enterprise Strategic Plan 2013-2016

This plan was expanded and updated from 2012 to provide more transparency in the setting of goals for the ERO Enterprise and to accommodate the 2013-2016 planning period.

The ERO Enterprise is a collaborative, international network comprised of the North American Electric Reliability Corporation (NERC) and the eight Regional Entities that brings together collective leadership, experience, judgment, skills, and technologies for ensuring the reliability of the North American bulk power system. This plan summarizes the ERO Enterprise's mission, vision, values and goals; and provides strategic direction and priorities for 2013 and beyond. The plan will be reviewed, revised, and supplemented every two years or more frequently as needed.

Mission
To ensure the reliability of the North American bulk power system.

Vision
To be the trusted leadership that ensures and continuously improves the reliability of the North American bulk power system by implementing relevant standards; promoting effective collaboration, cooperation, and communication around important risks to reliability; and utilizing expertise from the industry to produce outcomes that improve reliability.

Core Values and Principles
The following core values and principles serve as guidelines for the conduct and behavior of all involved in the ERO Enterprise.

Accountability and Independence — The ERO Enterprise will:

- Be accountable for the public responsibilities delegated to it (a public trust obligation).
- Be impartial, independent of special interests, and impervious to improper influence.
- Balance its own independent regulatory judgment with the need to involve those with expert knowledge and experience in bulk power system reliability matters.

Responsiveness — The ERO Enterprise will act in a timely manner on the basis of unfolding events, emerging reliability risks, and the needs of industry and other stakeholders.

Fairness and Inclusiveness — The ERO Enterprise will:

- Be open and transparent.
- Provide access for clear communication with stakeholders.

- Ensure the legitimate interests of all parties are duly considered and balanced in the development of policies and reliability standards, and in its programs and operations.
- Conduct compliance and enforcement actions judiciously and in proportion to risk, paying regard to risks both potential and actual (realized).

Adaption and Innovation — The ERO Enterprise will:

- Continuously assess and prioritize its goals.
- Embrace change and encourage new ideas that contribute to effective action.
- Recognize the complex relationships and potential tensions between reliability objectives and business imperatives (including cost control).
- Be nimble and artful in responding to novel, unfamiliar, and emerging challenges.

Excellence —The ERO Enterprise will:

- Promote and rely upon the active participation of the best technical leaders from industry.
- Strive for excellence and efficiency in all aspects of Enterprise activities.

Efficiency —The ERO Enterprise will make informed decisions regarding efficient use of its resources and resources shared by industry.

Integrity — The ERO Enterprise will:

- Maintain the highest levels of professional and ethical conduct.
- Be intellectually honest, truthful, candid, and without bias.
- Be rigorous and thorough in all it does, doing the right things the right way.
- Earn trust by treating every person with fairness and respect.
- Work to meet or exceed expectations of stakeholders.

Four Pillars for Success

In order to succeed, the ERO Enterprise will emphasize:

- ***Reliability*** – to address events and identifiable risks, thereby improving the reliability of the bulk power system.
- ***Assurance*** – to provide assurance to the public, industry, and government for the reliable performance of the bulk power system.
- ***Learning*** – to promote learning and continuous improvement of operations and adapt to lessons learned for improvement of bulk power system reliability.
- ***Risk-based Approach*** – to focus attention, resources and actions on issues most important to bulk power system reliability.

Strategic Goals 2013 – 2016

The ERO Enterprise has identified seven goals in the strategic areas of standards; compliance, registration and certification; risks to reliability; and coordination and collaboration.

Standards

Goal 1. **Develop clear, reasonable and technically sound mandatory reliability standards in a timely and efficient manner.** These standards establish threshold requirements for ensuring the bulk power system is planned, operated, and maintained in a manner that minimizes risks of cascading failures, avoids damage to major equipment, or limits interruptions of bulk power supply.

Objectives and valued outcomes include:

a. Standards are timely, clear and responsive to reliability and security risks.

Key deliverables include:

- Complete standards development governance and process reforms as identified in 2012 resolutions by the NERC Board of Trustees.
- Ensure all existing and new standards meet quality and results-based criteria[1] within five years with subsequent review every five years thereafter
- Evaluate significant bulk power system events (Category 3 and above) to identify gaps in standards and address any gaps
- Develop a bulk power system risk profile and assess standards compared to the profile, address the most important risk gaps
- Address all high-risks designated for control by a standard within one year or two years if technical study is required
- Address all new FERC directives within one year or two years if technical study is required; close existing directives by 2015 (by filing or negotiated resolution)

b. Standards are practical to implement and cost effective.

Key deliverables include:

- Facilitate smooth transition of new standards (e.g., CIP Version 5)
- Consolidate to a common set of application guides or RSAWs for all standards
- Identify and file requirements to be retired (Paragraph 81 Phase 2)
- Explore options for assessing the cost effectiveness of appropriate reliability standards

[1] Quality criteria are the attributes of excellent reliability standards as stated in Section 300 of NERC's Rules of Procedure. Results based criteria mean each requirement defines a performance outcome, risk mitigation, or essential competency necessary for a reliable bulk power system.

Compliance, Registration and Certification

Goal 2. **Be a strong enforcement authority that is independent, without conflict of interest, objective and fair.** The ERO retains and refines its ability to use standards enforcement when warranted and impose penalties and sanctions commensurate with risk.

Objectives and valued outcomes include:

a. The ERO registers entities commensurate with risk to the bulk power system and ensures all key reliability entities are certified to have essential capabilities.

Key deliverables include:

- Develop and implement BES exception process
- Evaluate certification program for sufficiency and effectiveness, modify as needed
- Develop framework and criteria for registration based on risk to the bulk power system
- Develop common and consistent registration processes, information systems and methods among regions

b. The ERO holds industry accountable for violations that create serious risk to the bulk power system; resulting actions are timely and transparent to industry.

Key deliverables include:

- Develop and implement Reliability Assurance Initiative (compliance reform)
- Develop and implement new caseload and mitigation aging curves and monitor caseload and mitigation performance
- Develop and implement enforcement strategies based on Reliability Assurance Initiative

Goal 3. **Promote a culture of compliance that addresses reliability risks across the industry.** The ERO works with industry to identify standards, procedures, practices and controls to address reliability risks.

Objectives and valued outcomes include:

a. Industry has effective procedures and programs to monitor, detect, correct, report, and prevent compliance, reliability, and security issues.

Key deliverables include:

- Develop and implement Reliability Assurance Initiative (compliance reform) (same as 2b)
- Make effective internal controls models and information available to industry
- Initiate compliance phase-in learning periods for new standards

b. The ERO uses efficient processes and proportional exercise of discretion to verify that compliance objectives are met by industry.

Key deliverables include:

- Continue to expand use of discretion through Find, Fix, and Track (FFT)
- Develop and implement Reliability Assurance Initiative (compliance reform) (same as 2b)

Risks to Reliability

Goal 4. **Identify the most significant risks to reliability.** The ERO identifies and prioritizes reliability risks, facilitates effective solutions and interventions, and monitors results.

Objectives and valued outcomes include:

a. Risks are identified and prioritized based on reliability impacts, cost/practicality assessments, projected resources, and emerging issues.

Key deliverables include:

- Continue to mature RISC and develop risk profile to include HILF issues
- Prepare an annual state of reliability report
- Develop project plans and business case assessments for high priority risks; implement or facilitate initiatives to address high priority risks (see 5a first bullet)

b. Events and system performance are consistently analyzed for sequence, cause, and remediation to identify reliability risks and trends, and to inform standards, compliance, and other programs. Industry is well informed of system events, emerging trends, risk analysis, lessons learned and expected actions.

Key deliverables include:

- Analyze significant events to identify gaps in standards, compliance effectiveness, registration, and risk controls effectiveness
- Make all bulk power system event reports available to industry through secure portal
- Provide lessons learned and recommendations from events and identified risks
- Merge event driven databases and cause codes into one (e.g., event analysis, TADS, GADS, relay mis-operations)

Goal 5. **Be accountable for mitigating reliability risks.** The ERO works with industry stakeholders and experts to ensure the mitigation of known risks to reliability.

Objectives and valued outcomes include:

a. The ERO is tracking industry accountability for critical reliability and security recommendations.

Key deliverables include:

- Manage risk control initiatives to be completed by ERO and coordinate other initiatives with industry (e.g., relay misoperations, situational awareness, human error, cyber attack)
- Develop and deploy a recommendations tracking system

b. Industry is aware of and is effectively addressing security vulnerabilities and threats. Industry security posture is being evaluated and continuously improved. During crisis situations, ERO facilitates sharing of information among industry, Regions, and government.

Key deliverables include:

- Expand security maturity model assessments to be widely accessible across industry
- Issue and track security recommendations to protect the bulk power system (related to 5a second bullet)
- Expand the use and value of security threat and vulnerability information sharing, analytics, and analysis
- Implement periodic wide area security exercises (e.g., GridEx)
- Increase security clearances available to industry and facilitate access to secured briefings through local fusion centers

Goal 6. **Promote a culture of reliability excellence.** The ERO facilitates a learning environment throughout the industry through event causal analysis, communication of lessons learned, tracking of recommendations, and implementation of best practices.

Objectives and valued outcomes include:

a. ERO is a leading resource to industry and policy makers for reliability information.

Key deliverables include:

- Publish quality reliability assessment reports (LTRA, seasonal and special reports)
- Promote effective actions as needed to address identified gaps in future reliability

b. Reliability models and data accurately represent system behavior and are shared among reliability entities.

Key deliverables include:

- Assess data and modeling needs and develop recommendations to ensure quality planning and operating data/models are available to registered entities across each interconnection
- Evaluate event disturbances using phasor measurements and other methods to assess sufficiency of data and models

Coordination and Collaboration

Goal 7. **Improve transparency, consistency, quality and timeliness of results; operate as a collaborative enterprise; and improve efficiencies and cost effectiveness.** The ERO accomplishes this through effective coordination, collaboration and process improvements. The ERO communicates expectations clearly and fosters collaboration to deliver important results in advancing system reliability. The ERO engages the support and expertise of stakeholders, is an efficient steward of resources, and leverages information systems to create efficiencies and process controls.

Objectives and valued outcomes include:

a. The ERO acquires, engages, and retains highly qualified talent suited to the mission.

Key deliverables include:

- Implement employee climate surveys and succession planning and promote favorable hiring and retention of ERO staffs
- Develop ERO qualifications requirements for auditors and other key positions across the ERO and implement training as needed

b. The ERO internal risks are understood and managed; ERO processes are effective, efficient, and continuously improved.

Key deliverables include:

- Develop test and deploy ERO enterprise applications, platform and database
- Develop five-year ERO self-assessment and close all recommendations from three-year assessment and FERC audit
- Implement an ERO-wide internal risk management program

Agenda Item 9
Board of Trustees Meeting
February 7, 2013

Standards

Action

Adopt or discuss reliability standards, interpretations, and procedures as follows:

9a. **Proposed Continent-wide Standards for Action**

i. BAL-003-1—Frequency Response — **Adopt**

ii. Paragraph 81, Phase I — **Adopt**

iii. TPL Table 1, Footnote b — **Adopt**

iv. Generator Verification — **Adopt**

a. MOD-025-2—Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

b. MOD-026-1—Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

c. MOD-027-1—Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

d. PRC-019-1—Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

9b. **Proposed Interpretations and Standards Addressing Interpretation Requests for Action**

i. Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee — **Adopt**

ii. Interpretation of CIP-002-3 for Oklahoma Gas and Electric c. Proposed Regional Standards for Action — **Adopt**

9c. **Proposed Regional Standards for Action**

i. IRO-006-WECC-2 - Qualified Transfer Path Unscheduled Flow (USF) Relief — **Adopt**

9d. **Reports for Action or Information**

i. MRO Regional Standards Development Procedure — **Adopt**

ii. Analysis of TOP in Light of Pacific SW Blackout — **Information**

iii. COM-003-1 - Operating Personnel Communications Protocols — **Information**

Agenda Item 9a.i
Board of Trustees Meeting
February 7, 2013

Frequency Response

Action

Adopt the following standards documents and direct staff to file with applicable regulatory authorities:

- **Reliability Standard - BAL-003-1 Frequency Response and Frequency Bias Setting**

  [Standard BAL-003-1 - Clean] [Attachment A] [Procedure]

- **Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for BAL-003-1 Frequency Response and Frequency Bias Setting**

  [VRFs and VSLs**]**

- **Implementation Plan for BAL-003-1 Frequency Response and Frequency Bias Setting**

  [Implementation Plan]

  - Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after adoption by the Board of Trustees (Board).
  - Requirement R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after adoption by the Board.

- **Definitions**

  The Frequency Response Standard Drafting Team (FR SDT) proposes the following three new definitions and one revised definition (Frequency Bias Setting):

  - Frequency Response Measure (FRM): The median of all the Frequency Response observations reported annually by Balancing Authorities (BAs) for frequency events specified by the electric reliability organization (ERO). This will be calculated as MW/0.1Hz.
  - Frequency Response Obligation (FRO): The BA's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.
  - Frequency Response Sharing Group (FRSG): A group, whose members consist of two or more BAs, that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.

- Frequency Bias Setting: A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a BA's Area Control Error equation to account for the BA's inverse Frequency Response contribution to the Interconnection, and discourage withdrawal through secondary control systems.

- **Retirements**

  Retire the following standard midnight of the day immediately prior to the effective date of BAL-003-1:

  - BAL-003-0.1b – Frequency Response and Bias

  The existing definition for Frequency Bias Setting should be retired midnight of the day immediately prior to the effective date of BAL-003-1.

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 large disturbances and system restoration activities. Data collection following these disturbances reveals a slow decline in the system's response time to stabilize frequency following a disturbance. This trend has been occurring over the last 10 years, and there is currently no confirmed reason for the apparent decline. However, further data collection, as advanced by the proposed BAL-003-1 standard, should assist in this investigation. The proposed BAL-003-1 Reliability Standard would set a minimum Frequency Response obligation for each BA, provide a uniform calculation of Frequency Response and Frequency Bias Settings that transition to values closer to natural Frequency Response, and encourage coordinated Automatic Generation Control operation.

Project 2007-12 Frequency Response was initiated in June 2007. The goal of the original Standard Authorization Request (SAR) was to develop a standard that would require entities to provide data in order to analyze Frequency Response to determine if there was a decline occurring and what was triggering the decline.

FERC Order No. 693 contained directives requiring the ERO to define an amount of Frequency Response necessary for reliable operation and a method to determine if the frequency response is achieved, in addition to other requirements as outlined below.

On March 18, 2010, FERC issued an Order Setting Deadline for Compliance (130 FERC ¶ 61,218 (2010)) and directed NERC to submit a modification to BAL-003-0 responsive to the directive in Order No. 693 within six months from the date of the issuance of the order. NERC filed a request for clarification and rehearing of the March 18 Order on April 19, 2010, and explained that compliance with a six-month deadline was impossible given the highly technical issues related to Frequency Response and the necessity of conducting studies and analyses. Following a technical conference and a filing with an action plan by NERC, FERC accepted NERC's anticipated May 2012 filing target date. On March 30, 3012, NERC filed a Motion for Extension of Time, and FERC established a deadline of May 31, 2013 for NERC to comply with the Order No. 693 directives (139 FERC¶ 61,097 (2012)).

Pertinent FERC Order No. 693 Directives

Para 375
Accordingly, the Commission approves Reliability Standard BAL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that: (1) includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) 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.

NERC's Disposition of the above:

(1) **BAL-003-1** includes VRFs and VSLs, which provided for an equally effective method for assigning levels of non-compliance in the compliance elements to the standard.

(2) **BAL-003-1** determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the reliability standard are being met. The drafting team has determined that a sample size on the order of at least 20 events is necessary to have a high confidence in the estimate of a BA's Frequency Response. Selection of the frequency excursion events used for analysis will be done via a method outlined in Attachment A to the standard. On average, these events will represent the largest two to three frequency excursions occurring each month where good data has been collected.

(3) **BAL-003-1** defines the necessary amount of frequency response needed for reliable operation for each BA with methods of obtaining and measuring that the frequency response is achieved.

   a. **BAL-003-1** defines the necessary amount of frequency response needed for reliable operation for each BA. (BAL-003-1 defines both an Interconnection Frequency Response Obligation and a BA Frequency Response Obligation.)

   b. **BAL-003-1** lists several methods that a BA may use to obtain Frequency Response. Requirement R1 allows BAs to participate in FRSGs to provide or obtain frequency response. BAs can also obtain frequency response through Supplemental Service or Overlap Regulation Service.

   c. **BAL-003-1** provides a methodology for determining the amount of Frequency Response a BA has delivered, and thereby achieved. FRS Form 1 and the underlying data retained by the BA will be used for measuring whether frequency response was provided. FRS Form 1 will provide the guidance on how to account for and measure frequency response. Attachment A of the Standard discusses the process the ERO will follow to validate the BA's FRS Form 1 data and publish the official Frequency Bias Settings.

Standard Development Process

This project progressed through the normal standards development process, including three postings for stakeholder comment, an initial ballot in December 2011, a successive ballot in November 2012, and a recirculation ballot in December 2012.

Unresolved Minority Issues

There were a few minority issues raised by industry stakeholders that were not resolved, as identified below:

Issue: A few stakeholders questioned a Requirement for the BA to provide Frequency Response when they typically do not own generation.

Response: The SDT explained that the NERC Functional Model and FERC cited the BA as the responsible party for providing Frequency Response and that this was outside the scope of the industry-approved SAR. The SDT also stated that there were several different methods available to the BA to provide Frequency Response and that the SDT had included these in the background document. The SDT further stated that any entity could submit a SAR addressing this issue to the Standards Committee for consideration and that the SDT supported this option***. NERC recognizes this matter must be addressed in some fashion, but there are various alternatives to do so. NERC will use the data and experience gained from this standard modification to assist in addressing this remaining question.***

Issue: A couple of commenters stated they believed that the standard should support the development of a market for supporting a BA in achieving the necessary Frequency Response.

Response: The SDT explained that this standard would provide for the metrics for Frequency Response, while the market would define itself. The SDT further stated a market could be created by a region, sub-region, ISO, RTO or other entity as appropriate to facilitate compliance.

Proposed VRFs and VSLs

The non-binding poll of VRFs and VSLs achieved a quorum with 76.28 percent of those who registered to participate in providing comments, and 76.30 percent of those who provided comments expressed support for the VRFs and VSLs that were proposed in the standard.

Additional Information

In March 2011, the NERC Planning Committee (PC) tasked the Transmission Issues Subcommittee (TIS, now the System Analysis and Modeling Subcommittee (SAMS)) with determining what criteria should be used to decide the appropriate level of interconnection-wide frequency response needed for reliability and the method best suited for measuring Frequency Response. The TIS started with a body of work already underway by the Resources Subcommittee (RS) and the Frequency Working Group (FWG) of the Operating Committee (OC), and the FR SDT. The TIS finalized its Frequency Response Initiative Report (FRI Report) and received acceptance of said report from the NERC OC and the NERC PC. The FR SDT adopted the methodology detailed in the FRI Report for calculating the Interconnection Frequency Response Obligation. However, the FR SDT did not adopt the method recommended in the FRI Report for measuring that Frequency Response is achieved. The FRI Report recommends use of linear regression as the method for measuring that Frequency Response is achieved while the FR SDT

has chosen to use the median value for determining that Frequency Response is achieved. The FR SDT believes that the linear regression methodology needs additional testing prior to being implemented as the recommended methodology. These two statistical differences will also be allowed to be examined by adoption of this standard.

A link to the project history and files is included here for reference:

[Project 2007-12 – Frequency Response]

Agenda Item 9a.ii
Board of Trustees Meeting
February 7, 2013

Paragraph 81, Phase I

Action

Adopt the retirement of the requirements and associated elements identified[1] in the set of reliability standards identified below, and direct NERC staff to file with applicable regulatory authorities:

- **Reliability Standards with Proposed Retirements:**

  [Clean Set of Affected Reliability Standards] [Redline Set of Affected Reliability Standards]

- **Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs):**

  The VRFs and VSLs for the requirements proposed for retirement would also be retired. Conforming changes were also made to VSLs of other requirements that reference the requirements proposed for retirement.

- **Implementation Plan for Retirement of Requirements in Paragraph 81:**
  [Implementation Plan]

  As set forth in the Implementation Plan, all of the requirements will be retired on the day of approval by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter after adoption by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such governmental authorities.

  After evaluating the options and consulting with the Standards Committee and Standards Committee Process Subcommittee, the Paragraph 81 (P81) drafting team determined that when the requirements are retired, the version numbers of the reliability standards will not be incremented, but the retired requirements and associated elements will be clearly marked as retired. Incrementing the version numbers of each reliability standard is impractical because, in some cases, a subsequent version has already been developed, while in other cases a retired requirement would create a gap in numbering. In both cases, renumbering the reliability standards would create an undesirable administrative burden for entities using certain software systems to manage their compliance programs.

- **Retirements**
  No complete reliability standard is being proposed for retirement, and all of the other requirements in each of the affected reliability standards will remain in continuous effect.

[1] The requirements and associated elements at issue are identified by the addition of "(Retired)" after the text of each proposed retirement.

Background

On September 30, 2011, the North American Electric Reliability Corporation (NERC) filed a petition with the Federal Energy Regulatory Commission (FERC) requesting approval of its proposal to make informational filings in a "Find, Fix, Track and Report" (FFT) spreadsheet of lesser-risk, remediated possible violations of reliability standards. On March 15, 2012, the FERC issued an order conditionally accepting NERC's FFT proposal. In P81 of that order, FERC stated:

> The Commission notes that NERC's FFT initiative is predicated on the view that many violations of requirements currently included in Reliability Standards pose lesser risk to the Bulk-Power System. If so, some current requirements likely provide little protection for Bulk-Power System reliability or may be redundant. The Commission is interested in obtaining views on whether such requirements could be removed from the Reliability Standards with little effect on reliability and an increase in efficiency of the ERO compliance program. If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief. In addition, or in the alternative, we invite NERC, the Regional Entities and other interested entities to propose appropriate mechanisms to identify and remove from the Commission-approved Reliability Standards unnecessary or redundant requirements. We will not impose a deadline on when these comments should be submitted, but ask that to the extent such comments are submitted NERC, the Regional Entities, and interested entities coordinate to submit their respective comments concurrently. *North American Electric Reliability Corporation,* 138 FERC ¶ 61,193 at P 81 (2012).

Consistent with P81, a draft Standard Authorization Request (SAR) was developed[2] to set forth criteria and a process to identify reliability standard requirements that either: (a) provide little protection to the Bulk Electric System; (b) are unnecessary; or (c) are redundant; and, thereafter, to have NERC file to retire the identified reliability standard requirements with appropriate governmental authorities.

In addition to addressing P81, the SAR was drafted consistent with what the Standards Process Input Group developed as Recommendation 4, as set forth on page 12 of *NERC's Recommendations to Improve The Standards Development Process* (April 2012), which states:

> Recommendation 4: Standards Product Issues — The NERC Board is encouraged to require that the standards development process address: The retirement of standards no longer needed to meet an adequate level of reliability.

[2] The draft SAR and a suggested list of reliability standard requirements embedded in the SAR for consideration in the Initial Phase was the product of collaborative discussions among the following entities and their members: Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Large Public Power Council, Electricity Consumers Resource Council, The Electric Power Supply Association, Transmission Access Policy Study Group, the North American Electric Reliability Corporation, and the Regional Entity Management Group.

Standard Development Process

The requirements proposed for retirement progressed through the normal standards development process, including three postings (one informal, two formal) for stakeholder comment over a six-month period. A draft SAR was posted in August 2012 for an informal comment period with an initial list of requirements proposed for retirement. A final set of standards with requirements proposed for retirement was posted for comment with an initial ballot ending in December 2012 and a recirculation ballot in January 2013.

The recirculation ballot for Project 2013-02 closed on January 17, 2013 with a quorum of 84.60 percent and approval of 95.22 percent.

Additional Information

A link to the project history and files is included here for reference: Project History and Files

Agenda Item 9a.iii
Board of Trustees Meeting
February 7, 2013

TPL Table 1, Footnote b

Action

Adopt the following standards documents and direct staff to file with applicable regulatory authorities:

- **Reliability Standard TPL-002-2b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

  [Link to TPL-002-2b clean] [Link to TPL-002-2b redline to last Board approved]

- **Reliability Standard TPL-001-3 – Transmission System Planning Performance Requirements**

  [TPL-001-3 - Clean] [TPL-001-3 - Redline to last approved]

  (Note - Table 1 appears in the first four of the current TPL standards but footnote 'b' only applies to TPL-002. Therefore, only TPL-002 was posted for industry comment and ballot. When the footnote has been approved by the Board of Trustees (Board), all four of the applicable TPL standards will be filed with the Commission.)

- **Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs)** – VRFs and VSLs are unchanged from the values previously approved by the Board.

- **Implementation Plan:** The Implementation Plans for each of the standards are unchanged from the plans previously approved by the Board.

  [Implementation Plan for Footnote 'b' in TPL-002-2b]

  [Implementation Plan for footnote 12 in TPL-001-3]

- **Retirements**
  Retire the following standards, as per the Implementation Plan:

  - 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)
  - TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Background

On April 19, 2012, FERC issued Order No. 762 remanding the proposed TPL-002-2b reliability standard (which included footnote b), as vague, unenforceable, and not responsive to the Commission's Order No. 693 directives. In a related matter, FERC proposed to remand the proposed TPL-001-2 reliability standard because of the inclusion of the proposed footnote b as Note 12 of that standard.

NERC was directed to revise footnote b in accordance with the directives of Order Nos. 762 and 693. In the same project, NERC also revised the corresponding Note 12 to the proposed TPL-001-2 reliability standard.

The revised footnote b clarifies that entities can plan to shed load under very limited circumstances, as long as there is no Adverse Reliability Impact to the Bulk Electric System (BES). The revised footnote includes specific requirements related to the stakeholder process, including stakeholder groups that must be involved, the minimum information that must be provided to stakeholders, and the establishment of threshold values for the amount of Non-Consequential Load that can be planned to be shed for N-1 Contingencies.

Data collected through a Section 1600 data request (approved by the Board in July 2012) was used by the Standards Drafting Team (SDT) to determine the threshold values specified in the stakeholder process. A two-level approach was developed based on these threshold values. Up to 25 MW of Non-Consequential Load loss can be planned to be shed by an entity without formal regulatory involvement or electric reliability organization (ERO) oversight, as long as the open and transparent stakeholder process is followed with involvement of the appropriate regulatory authorities. For planned load shedding of amounts of load above 25 MW, up to a ceiling of 75 MW, the entity must obtain ERO review of possible adverse reliability impacts, and applicable regulatory authorities must not object to the plan.

The proposed footnote b allows for existing stakeholder processes to be used, as long as they meet the criteria in the attachment to the footnote. For efficiency, the proposed approach allows the same footnote 'b' utilization plan resulting from a stakeholder process to remain in effect, as long as system conditions do not materially change.

The role of local regulatory authorities in the planning process is maintained, while ERO oversight, in the form of a review for possible adverse reliability impacts, has been added to the overall process requirements.

The Implementation Plans to the proposed footnote b and Note 12 provide the necessary time for entities to bring their planning programs into compliance with the changes.

Pertinent FERC Order No. 693 directives

This project addresses the five reliability directives associated with Project 2010-11 (the original footnote b project). In addition, 33 reliability directives associated with Project 2006-02 (the major revision of the TPL standards project) are awaiting resolution of footnote b for inclusion in the TPL standards.

Standard Development Process

This project progressed through the normal standards development process, including four postings for stakeholder comment over a seven-month period, an initial ballot in November 2012, a successive ballot in December 2012, and a recirculation ballot in January 2013.

Unresolved Minority Issues

There were a few minority issues raised by industry stakeholders that were not resolved.

Issue: Some commenters questioned the use of the stakeholder process, arguing that Order No. 762 did not mandate the use of the stakeholder process.

Response: The SDT developed the revised footnote b using the Board-approved TPL-002-2b standard as a starting point. FERC remanded the proposed standard because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand, and did not assure that BES reliability would be maintained. The SDT determined that more specificity around the stakeholder process would be directly responsive to the Commission's concerns articulated in Order No. 672.

Issue: Some commenters questioned facets of the proposed TPL-001-2a standard that were already approved by the ballot body and the NERC Board—specifically the application (or non application) of Note 12 for various planning events.

Response: The proposed TPL-001-2 reliability standard was approved by the ballot body in a different standards development project, and then subsequently approved by the NERC Board. The Standard Authorization Request (SAR) for the footnote b project used that approval as the starting point to modify footnote b and Note 12.

Issue: A number of respondents raised jurisdictional concerns with the approach used in footnote b, arguing that NERC is imposing itself into local planning processes in violation of its Section 215 authority.

Response: The SDT determined that the proposed footnote b preserves the role of local regulatory authorities, while limited the role of the ERO in local planning process and still allowing the ERO to review possible Adverse Reliability Impacts. This is responsive to Order No. 762 directing that the ERO have oversight of any uses of the proposed footnote b in the planning process.

Additional Information

A link to the project history and files is included here for reference:

[Assess Transmission Future Needs]

[Project2010-11_TPL_Table-1_Order]

Agenda Item 9a.iv
Board of Trustees Meeting
February 7, 2013

Generator Verification

Action

Adopt the following standards documents and direct staff to file with applicable regulatory authorities:

- **Reliability Standards**

  i. MOD-025-1—Verification of Generator Gross and Net Reactive Power Capability [MOD-025-2 clean]

  ii. MOD-026-1—Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions [MOD-026-1 clean]

  iii. MOD-027-1—Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions [MOD-027-1 clean]

  iv. PRC-019-1—Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection [PRC-019-1 clean]

- **Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs)**

  [MOD-025-2 VRFs and VSLs]

  [MOD-026-1 VRFs and VSLs]

  [MOD-027-1 VRFs and VSLs]

  [PRC-019-1 VRFs and VSLs]

- **Implementation Plans**

  [MOD-025-2 Implementation Plan] [PRC-019-1 Implementation Plan]

  The coordination activities in PRC-019-1 are most effectively completed just prior to the performance of a reactive capability test required under MOD-025-2. Hence, the standard drafting team (SDT) has followed the same implementation schedule in PRC-019-1 as defined in MOD-025-2. The implementation schedule set forth for these two standards requires that entities complete the applicable verifications in phases over a five-year period.

  [MOD-026-1 Implementation Plan] [MOD-027-1 Implementation Plan]

  The implementation schedule for MOD-026-1 and MOD-027-1 is the same. The implementation schedule set forth for these two standards requires that entities meet the Requirements by the first day of the first calendar quarter following applicable regulatory or Board of Trustees (Board) approval (or as otherwise made applicable in various jurisdictions), with the exception of R2 which allows a phased implementation

over a 10-year period. This phasing supports typical generating unit outage schedules (typically 10 years) for the collection of generator response data necessary for required verifications under these two standards.

- **Retirements**

  [MOD-024-1] and [MOD-025-1]

Background

Collectively, the five proposed Generator Verification Reliability Standards address generator verifications needed to support bulk power system reliability and enhance coordination on important technical items necessary for generation-to-grid coordination. These proposed reliability standards reduce the risk of generator trips during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions, and aim to ensure that Transmission Planners (TPs) and Planning Coordinators (PCs) have accurate models and model parameters on which to base system models and simulations. Four of the five standards are being presented for adoption; the fifth standard, PRC-024-1 – Generator Performance During Frequency and Voltage Excursions, is still in development and expected to be presented for Board adoption in May 2013.

All of the proposed reliability standards included in this project were developed from "Phase III & IV Planning Measures" that were translated into reliability standards as part of the Version 0 translation effort.

- MOD-024-1 and MOD-025-1 were combined into a single reliability standard, MOD-025-2, which requires verification of Real and Reactive Power of applicable generator and synchronous condenser facilities to ensure that accurate information is available for planning models.
- MOD-026-1 relates to the generator excitation control system and the plant volt/Var (Volt Ampere Reactive) control functions. The Generator Owner (GO) is required to provide a verified model to the TP according to the periodicity specified in the reliability standard so that model parameters used in dynamic simulations performed by the TP accurately represent the generator excitation control system or plant volt/Var control function behavior.
- MOD-027-1 requires GOs to provide a verified model to the TP according to the periodicity specified in the reliability standard in order to verify that the turbine/governor and load control or active power/frequency control model and model parameters used in dynamic simulations performed by the TP accurately represent generator unit real power response to system frequency variations.
- PRC-019-1 requires GOs, and TOs that own a synchronous condenser, to coordinate the voltage regulating system controls with the equipment capabilities and settings of Protection System devices and functions to avoid disconnecting the generator unnecessarily and to limit the extent of equipment damage when operating conditions exceed equipment capabilities or stability limits.

Pertinent FERC Order No. 693 directives

The Generator Verification SDT (GVSDT) has addressed six directives from Order No. 693 during the development of this set of proposed reliability standards. The Consideration of Issues documents for [MOD-024-1 and MOD-025-1] provide the details regarding how each directive was met.

Standard Development Process

All four proposed Generator Verification Reliability Standards progressed through the normal reliability standards development process. MOD-025-2, MOD-027-1 and PRC-019-1 were posted four times for stakeholder comments. MOD-026-1 was posted five times for stakeholder comments.

Recirculation ballots for MOD-025-2, MOD-026-1, MOD-027-1 and PRC-019-1 closed on December 21, 2012. The results of these ballots are listed below:

- MOD-025-2: quorum: 86.89 percent; approval: 73.06 percent
- MOD-026-1: quorum: 79.00 percent; approval: 79.36 percent
- MOD-027-1: quorum: 86.68 percent; approval: 74.27 percent
- PRC-019-1: quorum: 85.87 percent; approval: 73.63 percent

Unresolved Minority Issues

There were two minority issues raised by industry stakeholders that were not resolved, as identified below:

Issue: MOD-026-1: Some stakeholders indicated that the concept of "applicable unit" should be extended to include static Var generators and similar devices, and that all Facilities with an excitation control system and more than 100 MVA (Mega Volt Ampere) of capability should fall under this standard.

Response: Static Var generators and other similar devices, such as synchronous condensers, are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for TOs to be the owners of synchronous condensers. For these reasons, the drafting team believes that the peer review requirements of MOD-026-1 would not make sense for these additional devices and Facilities. Synchronous condensers do not generate real power as a source of revenue, so TOs paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. A TO is, therefore, highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding, the SDT has decided that if it is determined that there is a need to develop a reliability standard to model the expected behavior of dynamic voltage devices typically owned by TOs, it would be a more appropriate strategy to include synchronous condensers along with other transmission system dynamic reactive devices, such as static var compensators (SVCs) and static synchronous compensators (STATCOMs), etc., in a separate SAR.

Issue: MOD-025-2: A few entities suggested that the standard be revised to allow the use of engineering analysis in place of staged testing to meet the verification requirements of the standard.

Response: The GVSDT explained that engineering analysis could be appropriate in some cases, but not in place of staged testing because engineering analysis will not identify equipment problems and these equipment problems may not show up during normal operations. This would result in inaccurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability for the planning models used to assess Bulk Electric System reliability.

Proposed VRFs and VSLs

MOD-025-2 reflects the merging of two reliability standards (Board approved but remanded by FERC in Order No. 693) into a single standard. MOD-026-1, MOD-027-1, and PRC-019-1 are new reliability standards. All of the requirements in the proposed reliability standards are new, and the standard drafting team developed new VRFs and VSLs according to NERC and FERC guidelines.

Non-binding polls of VRFs and VSLs for each reliability standard were conducted. The results of those non-binding polls are listed below. NERC Reliability Standards staff has reviewed all proposed VRFs and VSLs and recommends them for adoption.

- MOD-025-2: quorum of 77.94 percent, with 64.24 percent in support of the VRFs and VSLs
- MOD-026-1: quorum of 75.88 percent, with 77.10 percent in support of the VRFs and VSLs
- MOD-027-1: quorum of 78.06 percent, with 68.93 percent in support of the VRFs and VSLs
- PRC-019-1: quorum of 78.51 percent, with 63.63 percent in support of the VRFs and VSLs
- PRC-024-1: the final non-binding poll closed after these materials were prepared and the results will be presented at the February 7, 2013 Board meeting.

Additional Information

A link to the project history and files is included here for reference:
http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Agenda Item 9b.i
Board of Trustees Meeting
February 7, 2013

Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee

Action

Adopt the following standards documents and direct staff to file with applicable regulatory authorities:

- **Interpretation**

  [Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee]

Background

This interpretation request was developed and submitted by the System Protection and Control Subcommittee (SPCS), which is under the direction of the NERC Planning Committee, to address the Federal Energy Regulatory Commission's (FERC) concern about protection system single point of failures documented in Order No. 754. It involves two standards: 1) [TPL-003-0a] – System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C) and 2) [TPL-004-0] – System Performance Following Extreme Events Resulting in the Loss of Two of More Bulk Electric System Elements (Category D). The interpretation addresses FERC's concern by responding to two questions:

1. The first question asks if an entity has the option of evaluating the two conditions presented in Table 1 of the standards that are separated by the word "or." The interpretation drafting team (IDT) concluded that an entity must evaluate both conditions on the basis of an ordered reading of the text and information found in the associated footnote.
2. The second question asks to what extent an entity must model a single point of failure of a protection system. The IDT concluded that an entity is permitted engineering judgment to select the protection system component failures for evaluation, which includes addressing all protection systems affected by the selected component.

Pertinent FERC Order No. 693 Directives

None

Standard Development Process

This project progressed through the normal Interpretation development process including two postings for stakeholder comment, an initial ballot in December 2012, and a recirculation ballot in January 2013.

Unresolved Minority Issues

There was one minority issue raised by industry stakeholders that was not resolved, as identified below:

Issue: Four industry commenters suggested that the interpretation should have an implementation plan ranging from 18 months to five years.

Response: The team considered development of an implementation plan and requested that NERC staff review the matter. Based upon this review, the team reached consensus that an implementation plan is not necessary, as the standard is clear on the required performance and providing an implementation plan would create amnesty for entities that are not currently fully compliant with the requirement.

Proposed Violations Risk Factors and Violation Severity Levels

None

Additional Information

A link to the project history and files is included here for reference:

[Interpretation 2012-INT-02 – Interpretation of TPL-003-0a and TPL-004-0 for the System Protection and Control Subcommittee]

Interpretation of CIP-002-3 for Oklahoma Gas & Electric

Action
Adopt the interpretation of CIP-002-3 for Oklahoma Gas & Electric (OGE) and direct staff to file with applicable regulatory authorities.

- **Interpretation**

  [Interpretation 2012-INT-05 - Interpretation of CIP-002-3 for Oklahoma Gas & Electric]

Background
OGE submitted a request for interpretation of CIP-002-3 asking for clarification of Requirement R1.2.5 in relation to SmartGrid Advanced Meter Infrastructure (AMI) functionality. Clarification was requested regarding whether a company's SmartGrid AMI functionality, which may be able to disconnect 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 and, if not, whether it should be included in the company's risk-based methodology.

Pertinent FERC Order No. 693 Directives
None

Summary
During the identification and documentation of the Risk-Based Assessment Methodology (RBAM), a responsible entity shall consider “Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more” as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the RBAM is not required to consider that asset. The Critical Asset identification method under CIP-002-3, Requirement R1, is based on a facts and circumstance-driven analysis and is not exclusively dependent on specific technology or specific types of systems or facilities.

Standard Development Process
This project progressed through the normal Interpretation development process including two postings for stakeholder comment, an initial ballot in December 2012, and a recirculation ballot in January 2013.

Unresolved Minority Issues
None

Additional Information
A link to the project history and files is included here for reference:

[Interpretation 2012-INT-05 - Interpretation of CIP-002-3 for Oklahoma Gas & Electric]

Agenda Item 9c.i
Board of Trustees Meeting
February 7, 2013

IRO-006-WECC-2 – Qualified Transfer Path Unscheduled Flow Relief

Action

Approve the following standard document and direct staff to file with applicable regulatory authorities:

- **Reliability Standard IRO-006-WECC-2 – Qualified Transfer Path Unscheduled Flow Relief**

  [IRO-006-WECC-2-clean] [IRO-006-WECC-2-redline to last approved]

- **Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for IRO-006-WECC-2 [VRFs and VSLs are available in the Standard above]**

- **Implementation Plan for IRO-006-WECC-2**
  The standard shall become effective on the latter of the first day of the first quarter at least 45 days after Regulatory approval, or upon complete implementation of applicable webSAS changes and FERC approval of this standard and the revised Unscheduled Flow Mitigation Plan Documents.

- **Definitions**
  None

- **Retirements**
  Reliability Standard IRO-006-WECC-1 – Qualified Transfer Path Unscheduled Flow Relief

Background

On March 15, 2012, the WECC Board of Directors (WECC Board) approved revisions to the WECC Unscheduled Flow Reduction Guideline (WECC Guideline). The FERC-approved version of IRO-006-WECC-1 specifically references the WECC Guideline. Therefore, it was necessary to revise the IRO-006-WECC-1 Reliability Standard to be consistent with the revisions approved by the WECC Board. Because the proposed IRO-006-WECC-2 Regional Reliability Standard does not mandate the implementation of the WECC Guideline but, rather, lays out specific requirements if the implementation of the WECC Guideline is requested and authorized, the revisions to this Regional Reliability Standard are limited to referencing the most current version of the WECC Guideline rather than a specific version. Additionally, the standard language was modified to conform with the latest reliability standard results-based template. These modifications do not alter the applicability, nor the actions required, of entities that were required to comply with IRO-006-WECC-1.

The proposed IRO-006-WECC-2 includes two requirements. Proposed Requirement R1 requires the Reliability Coordinator to approve or deny the request of a Transmission Operator of a Qualified Transfer Path for unscheduled flow transmission relief. Proposed Requirement R2 requires Balancing Authorities to meet the relief requirements identified in the WECC Guideline. These same actions were required in IRO-006-WECC-1.

Directives
None

Discussion
On March 15, 2012, the WECC Board approved revisions to the WECC Guideline. On June 25, 2012 the WECC Board approved the proposed IRO-006-WECC-2 as errata revisions to IRO-006-WECC-1. During the July 2012 NERC Standards Committee meeting, NERC staff advised WECC that the proposed revisions were more than errata changes and advised WECC to follow the FERC-approved WECC Reliability Standards Development Procedures to revise IRO-006-WECC-1.

Standard Development Process
WECC initiated the WECC Reliability Standards Development Procedures in July 2012. During two WECC comment periods and one NERC comment period, there were no requests from the Industry for changes to the document, nor did the Industry submit any comments indicating that the proposed revisions modified the intent of Requirements R1 or R2.

The drafting team made minor revisions to the VSLs to align them with current NERC guidance.

Unresolved Minority Issues
None

Links to the project history and files are included here for reference:
Project History and Files

Midwest Reliability Organization Regional Reliability Standards Process Manual

Action

Approve the following standards document, direct staff to update the Midwest Reliability Organization (MRO) delegation agreement and file with the applicable regulatory authorities for approval:

- **Version 5 of Midwest Reliability Organization Regional Reliability Standards Process Manual**
  [Clean] [Redline to prior version]

Background

Version 4.0 of the MRO Regional Reliability Standards Process Manual, Exhibit C (MRO Standards Development Procedure) to the MRO Regional Delegation Agreement was previously approved by FERC on June 25, 2012. Revisions to this document (version 5.0) do the following:

- Improve alignment with the NERC Standard Process Manual
- Incorporate a quality review process
- Expand roles and responsibilities (*e.g.*, Standards Committee)
- Improve alignment with the MRO Delegation Agreement, Exhibit C, Common Attributes
- Add a requirement for a five-year review
- Add clarifications to process development Steps 1 through 11 (Section IV)
- Expand Interpretations and Appeals (Section V)
- Update the Standard Authorization Request Form to include Interpretations (Appendix B)
- Add Errata (Section VI)
- Make minor format and language clean-ups

Version 5.0 of the MRO Standards Development Procedure was approved by the MRO Board of Directors on June 28, 2012. After Version 5.0 of the MRO Standards Development Procedure was posted for comment, the MRO Standards Committee reviewed and approved non-substantive changes in response to comments received. The MRO Standards Committee recommended that the MRO Board of Directors approve those changes, which it did on December 6, 2012. MRO requests that the NERC Board of Trustees also approve these changes.

Directives

None

The links to the project history and files are included here for reference:

- http://www.mro.webvote.oati.net/mro_rsvp/action/PubMainAction?type=Detail&id=26
- http://www.mro.webvote.oati.net/mro_rsvp/action/PubMainAction?type=Detail&id=16

Agenda Item 9d.ii
Board of Trustees Meeting
February 7, 2013

Analysis of TOP in Light of September 2011 Southwest Blackout Event

Action
None

Background
In May 2012, the Board of Trustees (Board) approved and directed staff to file the following reliability standards (collectively, the "TOP Standards") and associated implementation plans with applicable regulatory authorities:

- Reliability Standard TOP-001-2 Transmission Operations
- Reliability Standard TOP-002-3 Operations Planning
- Reliability Standard TOP-003-2 Operational Reliability Data

At the time of approval, the Board asked NERC staff to review the TOP Standards, specifically with regard to Interconnection Reliability Operating Limits (IROLs), and ensure that the lessons learned from the September 2011 Southwest Blackout Event ("Southwest Blackout") are addressed by the TOP Standards.

Summary
NERC staff reviewed the 10 recommendations from the Southwest Blackout report that apply to transmission operations and determined that the TOP Standards address many of the recommendations. In cases where the TOP Standards do not specifically address the recommendations, no new reliability gap would be created by implementation of the TOP Standards. The TOP Standards effectively provide for reliability in real-time transmission operations and are an improvement over approved reliability requirements in several key areas including next-day studies, data-sharing, and the establishment of system operating limits.

In cases where the recommendations from the Southwest Blackout report that apply to transmission operations are not directly addressed by the TOP Standards, a number of parallel activities are under way or are being expedited to address the recommendations. For example, the NERC technical committees are using the recommendations to formulate guidelines and lessons learned for use throughout the industry. Additionally, the recommendations that support development of improved monitoring tools have been included in the scope of Project 2009-02 (Real-time Reliability Monitoring and Analysis Capabilities) which is included in the 2013 Reliability Standards Development Plan for active work in 2013.

Agenda Item 9d.iii
Board of Trustees Meeting
February 7, 2013

Update on COM-003-1 – Operating Personnel Communications Protocols

Action
None

Background
The NERC Board of Trustees (Board), during its February 9, 2012 meeting, was presented with an Interpretation of the word "directive" as it is used in COM-002-2 Requirement R2. After considerable discussion, the Board expressed concern about a potential gap in critical communications between entities. To address this concern, the Board resolved the following:

> RESOLVED, that the Board approves the proposed Interpretation of COM-002-2 and directs that it be filed with Electric Reliability Organization (ERO) governmental authorities;
>
> FURTHER RESOLVED, that the Board directs the Standards Committee to complete developmental activities on proposed Reliability Standard COM-003 on a high priority basis; and
>
> FURTHER RESOLVED, that the Board directs that NERC management, working with stakeholders, prepare a memorandum describing best communications practices, including appropriate use of three-step communications, to be sent to registered entities promptly.

Pertinent FERC Order 693 Directives

Paragraph 540
"While the Commission identified concerns regarding COM-002-2, the proposed reliability standard serves an important purpose by requiring users, owners and operators to implement the necessary communications and coordination among entities. Accordingly, the Commission approves Reliability Standard COM-002-2 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to COM-002-2 through the Reliability Standards development process that: (1) expands the applicability to include distribution providers as applicable entities; (2) includes a new Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area view of a transmission operator or balancing authority and (3) requires tightened communications protocols, especially for communications during alerts and emergencies. Alternatively, with respect to this final issue, the ERO may develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26 in the manner described above. Finally, we direct the ERO to include APPA's suggestions to complete the Measures and Levels of Non-Compliance in its modification of COM-002-2 through the Reliability Standards development process." (emphasis added)

Discussion

Since the February 9, 2012 meeting, the proposed COM-003-1 standard has been posted three times for comment and ballot. The last successive ballot received a 53.57 percent approval rating, an increase of only three percent over its previous ballot. It is not clear, at this time, whether the current path of development will result in a standard that is acceptable to stakeholders and meets the outstanding FERC directive on communications and the resolution adopted by the NERC Board in February 2012. After careful consideration of available options and in consultation with the Standards Committee, the following standard development steps will be taken to develop a standard that is acceptable to stakeholders and meets the outstanding FERC directive:

1. Convene an industry conference February 14-15, 2013 with the drafting team and industry to discuss comments, develop solutions, and build industry consensus. A two-session meeting (afternoon of the first day and morning of the second day) will include presentations on: (1) the issues identified by industry comments; (2) the FERC directives; and (3) the August 2003 Blackout report recommendations. In addition, two to three panels will be assembled to discuss the key issues and attempt to build consensus.
2. The drafting team will convene following the meeting to develop a new draft standard informed by the discussion, with posting to industry of the draft standard in February 2013.
3. The drafting team will meet in April 2013 to consider comments and post for 10-day recirculation ballot.[1]
4. Expected Board consideration: May 2013

A link to the project history and files is included here for reference:
Op_Comm_Protocol_Project_2007-02

[1] If the ballot does not pass, next steps will be considered and recommendations will be made to the Board.

Agenda Item 10
Board of Trustees Meeting
February 7, 2013

Standards

Action

Approve or discuss standards process updates as follows:

10. **Standards Process Update**
    a. Standards Committee Strategic Plan and Work Plan — **Approve**
    b. Standards Committee Charter — **Approve**
    c. Standard Processes Manual Changes — **Approve**
    d. Standards Committee Chair and Vice Chair — **Approve**
    e. Status of SPIG Recommendations and Board Resolutions to Standards — **Information**

Agenda Item 10a
Board of Trustees Meeting
February 7, 2013

Standards Committee Strategic Plan and Work Plan

Action

Approve the Standards Committee (SC) Strategic Plan and Work Plan.

- **SC Strategic Plan**

  [Link to Standards Committee Strategic Plan]

- **SC Strategic Work Plan 2013-2015**

  [Link to Standards Committee Strategic Work Plan 2013-2015]

Background

In October 2012, the SC formed a small, ad hoc group to work with NERC staff to develop a strategic vision for the SC to align the SC's work with the electric reliability organization's (ERO's) strategic direction. This ad hoc group has developed a Strategic Plan, along with a Work Plan that includes specific tasks and milestones for executing the plan. The Strategic Plan aligns closely with the November 2012 Board resolution calling for improvements to the reliability standards development process. The SC approved the strategic plan and work plan at its January 2013 meeting.

The SC Strategic Plan sets forth the vision and mission for the SC. Further, the plan describes the guiding principles, and sets the foundation for refocusing the activities of the SC.

Based on this plan, a companion SC Strategic Work Plan was developed, which is the tactical implementation plan of the SC Strategic Plan. This work plan is meant to be a living document that addresses the current strategic issues facing the SC. The SC Strategic Work Plan covers the period from 2013-2015. To ensure the SC Strategic Work Plan is current and consistent with the SC Strategic Plan, an annual fourth quarter review shall be completed as part of the overall development of the Reliability Standards Development Plan, and updates to the SC Strategic Work Plan will be made as needed.

Agenda Item 10b
Board of Trustees Meeting
February 7, 2013

Standards Committee Charter

Action

Approve the Standards Committee (SC) Charter.

- **SC Charter**

  [Link to Standards Committee Charter-clean]

  [Link to Standards Committee Charter-redline to last Board approved]

Background

In October 2012, the SC formed a small, ad hoc group to work with NERC staff to develop a strategic vision for the SC. This ad hoc group revised the SC's Charter in response to the Board's November 2012 resolution calling for improvements to the reliability standards development process and to align the SC Charter with the SC's Strategic Plan. The changes to the SC Charter were approved by the SC in January 2013.

The SC's enhanced charter includes, among other things, changes that clarify accountability of the SC to the Board of Trustees for development of reliability standards that provide for the reliability of the bulk power system and addresses the role and terms of officers. In addition, the Charter commits to coordinate with the Reliability Issues Steering Committee (RISC) and other NERC standing committees.

The proposed enhancements include the following duties and responsibilities for the SC:

- Appointment, monitoring, and direction of agile and focused standard drafting teams with subject matter experts that include a facilitator, a technical writer, and compliance, legal, and regulatory experts.
- Coordination with the RISC to develop a reliability standards development plan that prioritizes and aggressively pursues work that will result in a body of high-quality, results-based standards.
- Establishment and facilitation of the informal and formal collaborative, consensus building processes with stakeholder groups and NERC standing technical and regional committees throughout all stages of reliability standards development.
- Establishment of a quality assurance and quality control process for reliability standards that addresses factors, including clarity, completeness, sufficient detail, rational result, auditability and enforceability as well as compatibility with existing reliability standards.
- Requests input from the Board on their selection, and reinforces the SC's accountability to the Board.
- Development of a long-term, multi-year strategic vision that describes the goals and direction for the development of reliability standards consistent with the strategic and business plans of NERC.

Agenda Item 10c
Board of Trustees Meeting
February 7, 2013

Standard Processes Manual

Action

Approve the following documents and direct that the Revised Standard Processes Manual (SPM) (Appendix 3A of the NERC Rules of Procedure) be filed with regulatory authorities.

[Standard Processes Manual-Clean] [Standard Processes Manual-Redline to Last Approved]

Background

Proposed revisions to NERC's standards development processes were developed in response to recommendations made to the Board of Trustees (Board) by the Member Representatives Committee's Standards Process Input Group in May 2012, specifically Recommendations 1, 4, and 5. The revisions to the SPM resulted in a streamlined formal process and are consistent with ANSI Essential Requirements. Specifically, the revisions are to:

- Memorialize the intent to revise drafting team compositions to ensure they are appropriately equipped to meet reliability objectives (*e.g.*, add legal and compliance experts)
- Incorporate reference to compliance assessment tool development, such as Reliability Standards Audit Worksheets (RSAWs), cooperatively and in parallel with standard drafting
- Streamline commenting and balloting, including provisions for:
  - Summary responses to comments and elimination of the obligation to respond in writing at every stage of the comment process
  - Eliminating negative votes without comments in the calculation of consensus
  - Quality reviews to be conducted in parallel with standard development
- Incorporate guidance for the appropriate role and scope of Interpretations, to be consistent with guidance from the NERC Board
- Reduce the requirement for periodic review to be consistent with ANSI minimum requirements
- Incorporate a waiver provision to allow for modifications to the standards development process for good cause, with five days notice and reporting of the exercise of a waiver to the Board's Standards Oversight and Technology Committee.

The revisions were developed by the Standards Committee Process Subcommittee, and, since June 2012, were posted for three stakeholder comment periods, an initial ballot, successive ballot, and a recirculation ballot. The recirculation ballot concluded in January 2013. The results of the recirculation ballot were not available at the time these materials were distributed and will be reported at the meeting.

A small number of changes are needed to the Rules of Procedure to reflect the revisions to the SPM. These changes will be brought to the Board for action at a later date. In addition, some aspects of the SPIG's recommendations, such as those related to the formation of drafting teams, improved project management discipline for standards projects, and development of results-based standards, do not require specific changes to the SPM, and work is ongoing to implement those changes at the appropriate phase of each active and future standards project.

Agenda Item 10d
Board of Trustees Meeting
February 7, 2013

New Standards Committee Chair and Vice Chair

Action

Approve the nominations of:

- Mr. Brian Murphy of NextEra Energy to serve as Chair of the Standards Committee
- Mr. Scott Miller of MEAG Power to serve as Vice Chair of the Standards Committee

Background

The Standards Committee (SC) is a NERC stakeholder committee comprised of two members from each of the 10 industry segments represented in the NERC Registered Ballot Body. It serves and reports directly to the Board of Trustees (Board). The SC manages the NERC standards development process for the development of North American-wide Reliability Standards with the support of the NERC staff to achieve broad bulk power system reliability goals for the industry. The SC protects the integrity and credibility of the standards development process.

Allen Mosher was elected as Chair of the SC in January 2012 to a two-year term, but resigned in late 2012 with one year remaining in his elected term. During its January 2013 meeting, the SC held an election for a new Chair to fill the remainder of Mr. Mosher's term. The SC concurrently held an election for a new Vice Chair to serve for a one-year term. NERC is presenting the SC Chair and Vice Chair to the Board for approval pursuant to Section 5 of the revised Standards Committee Charter, also presented to the Board for approval on February 7, 2013. Section 5 provides that the SC officer candidates shall be presented to the NERC Board for approval.

Agenda Item 10e
Board of Trustees Meeting
February 7, 2013

Status of Standards Process Input Group Recommendations and Response to Board of Trustees Resolutions

Action
Information

Background
In May 2012, the Board of Trustees (Board) approved five recommendations proposed by the Member Representatives Committee's (MRC's) Standards Process Improvement Group (SPIG). Three of these recommendations, specifically Recommendations 1, 4, and 5 were delegated to the Standards Committee (SC), which were implemented through a draft set of revisions to the Standard Processes Manual (SPM). The revisions to the SPM resulted in a streamlined formal process and are consistent with ANSI Essential Requirements.

The proposed changes to the SPM achieved an affirmative successive ballot outcome of 84.48 percent approval on December 20, 2012. At the time of preparation of these materials, the final 10-day recirculation ballot was still ongoing. An update will be provided at the February 7, 2013 Board meeting.

SPIG Recommendation 2 was addressed through the formation of the Reliability Issues Steering Committee (RISC). SPIG Recommendation 3 is being addressed by NERC management.

In addition to process improvements made in response to the Board-approved May 2012 SPIG recommendations, and in response to the Board's November 2012 resolution calling for improvements to the reliability standards development process, the SC formed a small group to work with NERC staff to develop a strategic vision for the SC that focused on governance and scope changes to better align the SC's work with the ERO's strategic direction. Based on the work of this group, the SC is recommending additional improvements reflected in the draft SC Strategic Plan, the draft SC Strategic Work Plan, and the proposed SC Charter, which are all presented to the Board at the February 7, 2013 meeting for approval.

The following table provides additional detail on the implementation of the SPIG Recommendations and the November 2012 Board Resolution.

Table I: Mapping Standards Committee Actions to SPIG Recommendations and Board Resolution

Action/Recommendations	Standards Committee Actions
Standards Process Improvement Group (SPIG) recommendations:[1]	
1. American National Standards Institute - Maintain ANSI accreditation unless ANSI prevents efficiency gains	The revisions to the SPM are consistent with ANSI Essential Requirements. ANSI accreditation will be maintained unless it will hinder efficiency gains.
4. Standards Product Issues - Require the standards development process to address:	
• The use of results–based standards (RBS)	The 2013-2015 Reliability Standards Development Plan (2013-2014 RSDP) includes incorporation of results-based standards principles into all projects going forward. Currently a white paper clarifying these principles as well as training is being developed for drafting team members.
• Cost effectiveness of standards and standards development	The SC, in October 2012, approved the Cost Effective Analysis Process (CEAP) document along with an Implementation Whitepaper. Two standard projects will be chosen to pilot the components of CEAP: Cost Impact Analysis and Cost Effectiveness Analysis.
• Alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs)	NERC Standards Developers will include ERO compliance and enforcement staff in standards development to ensure they are auditable and enforceable. Further, compliance assessment tools, such as the RSAWs, will be developed in conjunction with the standards. Until maturity of this engagement, standards will continue to include Measures.
• The retirement of standards no longer needed to meet an adequate level of reliability	This effort began with the Paragraph 81 Phase I project (*i.e.*, retire or modify FERC-approved Reliability Standard requirements that provide little protection to the reliable operations of the BES, are redundant or unnecessary, or retire or modify a FERC-approved Reliability Standard requirement to increase the efficiency of the ERO's compliance programs). The 2013-2015 RSDP includes incorporation of Paragraph 81 principles into all projects going forward.

[1] Recommendations 2 and 3 (formation of RISC and Interface with Regulatory and Governmental Authorities) are not included in the table as they are outside of the standards development area.

Table I: Mapping Standards Committee Actions to SPIG Recommendations and Board Resolution

Action/Recommendations	Standards Committee Actions
5. Standards Development Process and Resource Issues — Require the standards development process to be revised to improve timely, stakeholder consensus in support of new or revised reliability standards.	The SC has proposed modifications to the SPM: • **Section 3.0**: Revised drafting team composition to include lawyers and compliance experts; incorporated compliance assessment tool development, such as RSAWs, with standard drafting • **Section 4.0**: Streamlined commenting and balloting process, including: ▪ Provisions for summary responses to comments and elimination of the obligation to respond in writing at every stage of the comment process; ▪ Eliminate negative votes without comments in the calculation of consensus; ▪ Provisions 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

Agenda Item 12
Board of Trustees
February 7, 2013

Reliability Issues Steering Committee (RISC) Recommendations

Action
Accept

Background
The RISC is an advisory committee that reports directly to the NERC Board of Trustees (Board) and triages and provides front-end, high-level leadership and accountability for nominated issues of strategic importance to bulk power system (BPS) reliability. The RISC assists the Board, NERC standing committees, NERC staff, regulators, Regional Entities, and industry stakeholders in establishing a common understanding of the scope, priority, and goals for the development of solutions to address these issues. In doing so, the RISC provides a framework for steering, developing, formalizing, and organizing recommendations to help NERC and the industry effectively focus their resources on the critical issues needed to best improve the reliability of the BPS. Benefits of the RISC include improved efficiency of the NERC standards program. In some cases, that includes recommending reliability solutions other than the development of new or revised standards and offering high-level stakeholder leadership engagement and input on issues that enter the standards process.

To carry out its responsibility to provide a framework for steering, developing, formalizing and organizing recommendations to help NERC and the industry effectively focus resources on the critical issues needed to best improve the reliability of the BPS, the RISC has completed an initial assessment of all ongoing efforts at NERC and makes this report to catalogue the RISC recommendations.

Summary
Chris Schwab, Chair, will review the RISC's recommendations and ask the Board to accept them. The recommendations are as follows:

- The Board adopt this strategic prioritization and endorse continued work by the RISC on a gap analysis on the high priority and then the medium priority issues.
- The Board direct NERC to incorporate these priority rankings into the development of ERO business plans, and direct NERC standing committees to incorporate these priority rankings into the development of their plans.
- The Board direct the RISC be directed to work with NERC staff and standing committees' leadership to create a data-driven reliability strategy development process that integrates with budget development and overall ERO planning (e.g., standing committee planning, department, and employee goal setting).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ERO Priorities

RISC Recommendations

January 18, 2013

RELIABILITY | ACCOUNTABILITY






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Introduction

The Reliability Issues Steering Committee (RISC) is an advisory committee that reports directly to the NERC Board of Trustees (Board) and triages and provides front-end, high-level leadership and accountability for nominated issues of strategic importance to bulk power system (BPS) reliability. The RISC assists the Board, NERC standing committees, NERC staff, regulators, Regional Entities, and industry stakeholders in establishing a common understanding of the scope, priority, and goals for the development of solutions to address these issues. In doing so, the RISC provides a framework for steering, developing, formalizing, and organizing recommendations to help NERC and the industry effectively focus their resources on the critical issues needed to best improve the reliability of the BPS. Benefits of the RISC include improved efficiency of the NERC standards program. In some cases, that includes recommending reliability solutions other than the development of new or revised standards and offering high-level stakeholder leadership engagement and input on issues that enter the standards process.

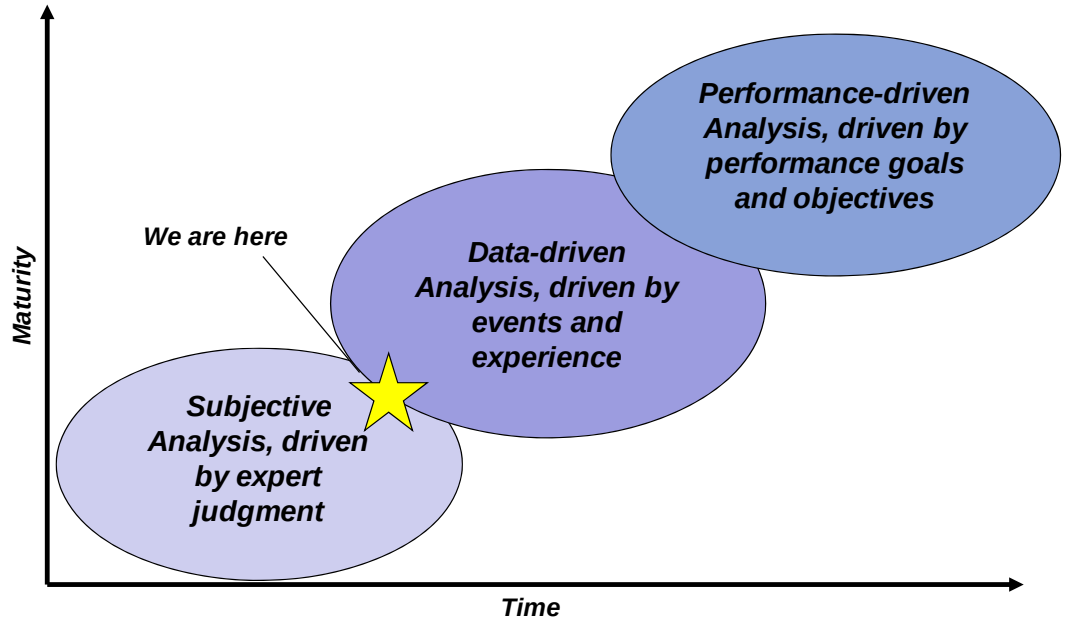
To carry out its responsibility to provide a framework for steering, developing, formalizing and organizing recommendations to help NERC and the industry effectively focus resources on the critical issues needed to best improve the reliability of the BPS, the RISC has completed an initial assessment of all ongoing efforts at NERC and makes this report to catalogue the RISC recommendations.

NERC staff identified 41 active or planned efforts at NERC related to reliability threats, and combined them into several general categories of risk. The RISC's initial assessment followed the steps below:

- RISC members were asked to consider the risk impact and probability, the associated controls currently in place and their effectiveness, and any gaps in control, then ultimately provide a "post-control" priority that indicates where they felt the risk should be ranked within the ERO reliability strategy.
- The RISC met in-person three times to discuss, refine, and ultimately achieve consensus on the prioritization of these issues. Members used their extensive knowledge and expertise, as well as that of their colleagues and co-workers, to consider the relative reliability importance of each area.
- The RISC received a briefing on NERC events analysis and trends. While NERC is making great strides in developing the data and analysis that would indicate the greatest risks to the BES based on past events, more work is needed for this to become a foundation for risk prioritization.

The results of the prioritization are presented on the next pages of this report. When considering the results, please remember the following:

- While "expert judgment" is invaluable, as the process matures, the RISC recommends that NERC focus on data collection and clear problem definition after it performs gap analyses, as well as defining success and developing metrics for all projects going forward. With mature data collection and management for decision support, as well as formal decision making processes, expert judgment can more effectively be used in the analysis of performance and project effectiveness.



- The RISC has not considered whether or not certain elements are within NERC's scope. Even within NERC's scope, some issues may be more appropriately addressed by or in coordination with other organizations, such as Regional Reliability Organizations, the North American Transmission Forum, the Electric Power Research Institute, the Institute to Electrical and Electronics Engineers, and other similar entities.
- The RISC did not attempt to determine the regional nature of various issues. Certain issues may be more applicable in some Regions than in others.

Resource Allocation Estimates

The goal of the tables below is to provide a rough estimate of how NERC's anticipated activities in 2013 align with the priorities identified by the RISC. The RISC was formed in August 2012, and developed this list of strategic priorities since its formation. As such, the RISC strategic prioritization is not currently integrated into ERO planning and budgeting processes. Since the ERO's current budget categories were created prior to the RISC strategic prioritization, NERC senior managers developed the resource allocation estimates included in this report by estimating the percentage of their 2013 resources and contract budget that they anticipate will be focused on the major categories (e.g. High and Medium Priority). This preliminary analysis shows the current plans already have a reasonable degree of alignment with the RISC priorities, with as much as 65% of operating staff focusing on High and Medium Priority areas.[1] NERC is in the process of implementing systems and procedures to facilitate the budgeting and tracking of resources by major activity.

[1] The estimates only relate to line operating area resources and exclude an allocation of General and Administrative Program Area resources, including items such as Executive, Legal, Accounting, Finance, Human Resources, and Information Technology.

High-Priority Issues

Between approximately 41% and 50% of NERC's Resources in 2013

Description

The RISC unanimously concluded that the issues below should be the top strategic focus for the ERO and are common across the ERO.

High Priority Issues	Prevention and Mitigation Controls	Estimated Resource Allocation 2013
Cyber Attack: We have an event caused by a cyber attack on BES cyber assets.	Applicable NERC Standards: CIP-002 through -009 version 3 CIP-002 through -009 version 4 EOP-004; EOP-001, -005, -006, -008, -009 address generically	Approx. 10 - 11%
	NERC Standards Development Projects: 2008-06 Cyber Security – Order 706 (CIP-002 through -011 version 5; awaiting filing)	
	Other NERC Activities: ESISAC Monitoring and Metrics Classified Government Security Briefings for Cleared Personnel Cyber Risk Preparedness Assessments (CRPA) Grid Security Exercises Grid Security Conferences Implementation of DOE/DHS/White House Electricity Subsector Cybersecurity Capability Maturity Model Implementation of DOE Cyber Security Risk Management Process CIP Audits and Enforcement CIPC Efforts: Subcommittees, Working Groups and Task Forces HILF Efforts Coordinated Action Plan ESCC New NERC Guidelines	
	Non-NERC Activities: Entities: Internal and independent programs, monitoring, and testing	

High Priority Issues	Prevention and Mitigation Controls	Estimated Resource Allocation 2013
Workforce Capability and Human Error: We have an event because someone (e.g., an operator or a field technician) makes a mistake or has an error in judgment.	Applicable Standards: PER-001 through -005	Approx. 6% - 9%
	Standards Development Projects: 2007-02 Operating Personnel Communications Protocols 2010-01 Support Personnel Training (Future)	
	Other NERC Activities: Events Analysis Program Lessons Learned Event Analysis Subcommittee Trend Working Group Certification Training	
	Non-NERC Activities: Transmission Forum: Efforts related to Human Performance and Events Analysis, Lessons learned Entities: Simulations, management oversight, procedures and practices, human performance and operator training, human error prevention tools Vendors: Improvements to Human/Machine Interfaces i.e., Man-Machine Interfaces	

High Priority Issues	Prevention and Mitigation Controls	Estimated Resource Allocation 2013
Protection Systems: We have an event become worse due to a protection system failing to operate correctly.	Applicable NERC Standards: PRC-001, -003 through -005, -012 through -017, -023 TPL-001 through -004	Approx. 8% - 10%
	NERC Standards Development Projects: 2007-06 System Protection Coordination 2010-05.1 Protection Systems Misoperations 2010-13.2 Generator Relay Loadability 2010-05.2 SPS and RAS (Future) 2010-13.3 Stable Power Swings (Future)	
	Other NERC Activities: Protection System Misoperation Task Force System Protection and Control Subcommittee Regional Criteria Operating Committee Event Analysis Subcommittee Trend Working Group Event Analysis Program Lessons Learned	
	Non-NERC Activities: IEEE: Research and development efforts Entities: Internal company procedures Transmission Forum and/or Generator Forum: Peer reviews of SPS	

High Priority Issues	Prevention and Mitigation Controls	Estimated Resource Allocation 2013
Monitoring and Situational Awareness: We have an event due to a control center or similar facility either not receiving or understanding information related to system conditions.	Applicable NERC Standards: BAL-005 COM-001 through -002 FAC-001 IRO-001 through -005 IRO-008, -010, -014 through -016 NUC-001 TOP-001, -003 through -006 VAR-001	Approx. 17% - 20%
	NERC Standards Development Projects: 2007-02 — Operating Personnel Communications Protocols 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (Future)	
	Other NERC Activities: Certification and Registration RCIS Events Analysis Program Lessons Learned NERC Alerts SAFNR IINERC Bulk Power System Awareness NERC Functional Model Operating Committee Event Analysis Subcommittee EMS Task Force	
	Non-NERC Activities: Vendors: Alarms, Disturbance Monitoring Equipment Entities: Implementation of Teams (shared SA)	

Next steps

With respect to each High Priority Issue, the RISC began a detailed gap analysis at its January 21, 2013 meeting. For each of these issues, the gap analysis will address the following:

1. Are the existing efforts sufficient, or do we need to add new efforts or make or incremental improvements to what we have? Are all of the existing efforts needed?
2. Ensure that any new effort is in NERC's scope or appropriately directed to the right organization. We want to avoid duplication of efforts on issues.
3. As we consider existing, new, and incremental efforts:
    a. What gap was identified that the effort is meant to solve — what is the problem statement?
    b. What data is available to appropriately scope any new activity?
    c. How will we measure performance? What metrics will define and track success?
    d. How will we fund the incremental project without increasing the budget? What resources currently directed to lower priority resources will be redirected toward these higher-priority issues?
    e. If a budget increase is necessary, justify it and explain why funding can't be obtained through a re-allocation of resources.

Medium-Priority Issues

Between approximately 13% and 15% of NERC's Resources in 2013

Description

These areas should be researched to determine what, if anything, should be focused on in addition to (or in replacement of) existing activities. In general, these issues may be more regional in nature or may need to be more narrowly focused to determine whether any incremental work is needed.

Medium Priority Issues	Prevention and Mitigation Controls	Estimated Resource Allocation 2013
Operational Modeling and Model Inputs: We have an event because models and/or model inputs used in day-ahead and/or real-time were inaccurate or not available.	Applicable NERC Standards: BAL-005 COM-002 FAC-009, -014 INT-001 through -010 IRO-002, -003, -005, -008, -010 MOD-010, -012, -016, -017, -018, -019, -020, -021 NUC-001 TOP-002, -003, -005, -006	Approx. 2% - 3%
	NERC Standards Development Projects: 2010-03 – Modeling Data (Future) 2010-04 Demand Data (Future) 2008-12 Coordinate Interchange Standards (Future) 2012-05 ATC Revisions – Order 729 (Future) 2007-09 Generator Verification	
	Other NERC Activities: Model Validation Working Group ERAG-MMWG – Eastern Interconnection Western Interconnection Response to AZ/SoCal Outage	
	Non-NERC Activities: None identified	

Medium Priority Issues	Prevention and Mitigation Controls	Estimated Resource Allocation 2013
Equipment Maintenance and Management: We have an event because we are not maintaining our equipment correctly or on schedule and something failed.	Applicable NERC Standards: PRC-005,-008, -011, -017	Approx. 3%
	NERC Standards Development Projects: 2007-17.2 Protection System Maintenance and Testing 2013-01 Cold Weather Preparedness	
	Other NERC Activities: Spare Equipment Database Task Force	
	Non-NERC Activities: Entities: Maintenance Programs. Vendors: Warranty Requirements.	
Coordinated Attack on Multiple Facilities: We have an event caused by a physical attack on infrastructure.	Applicable NERC Standards: CIP-001 EOP-001, -005, -006, -008, -009 address generically	Approx. 3%
	NERC Standards Development Projects: None	
	Other NERC Activities: ESISAC Monitoring CIP Audits Grid Security Conference Grid Security Exercise CIPC Efforts RCIS OC, PC, CIPC, and associated Subcommittees	
	Non-NERC Activities: Local Government: Local Security efforts.	

Medium Priority Issues	Prevention and Mitigation Controls	Estimated Resource Allocation 2013
Generator Availability: We have an event because generation is not available when needed (not enough generation operating).	Applicable NERC Standards: BAL-001 through -003 IRO-003, -005, -014, -015 MOD-010, -012 TOP-006	Approx. 3%
	NERC Standards Development Projects: 2010-13.2 Generator Relay Loadability 2007-12 Frequency Response 2010-14.1 Balancing Authority Reliability-Based Controls	
	Other NERC Activities: NERC Reliability Assessments Generating Availability Data System and GADS Working Group	
	Non-NERC Activities: ISOs, RTOs: Market Solutions	
Increased dependence on Natural Gas Generation: We have an event because of insufficient natural gas deliveries.	Applicable NERC Standards: None specifically address this issue	Approx. 2% - 3%
	NERC Standards Development Projects: None	
	Other NERC Activities: NERC Reliability Assessments OC, PC, associated Subcommittees	

Medium Priority Issues	Prevention and Mitigation Controls	Estimated Resource Allocation 2013
	Non-NERC Activities: State and Local Regulators: Resource Adequacy Provisions ISOs, RTOs, Pipelines: Market Solutions Entities: Planning, Regulatory communications and lobbying Industry: Awareness and Study, Conferences FERC: Technical Conferences; docket on inter-industry coordination NAESB: Gas Electric Harmonization Task Force	

Next steps

For each of these issues, NERC should be considering the following:

1. What specific areas we should be focusing on?
2. Ensure that any new effort is in NERC's scope or is appropriately directed to the appropriate organization. We want to avoid duplication of efforts on issues.
3. What is the scope of this issue (e.g., should a Region work on this issue and share its results with the larger NERC community)?
4. Are the existing efforts sufficient, or do we need to add new efforts or make incremental improvements to what we have? Are all of the existing efforts needed?
5. As we consider existing, new, and incremental efforts:
    a. What gap was identified that the effort is meant to solve — what is the problem statement?
    b. What data is available to appropriately scope any new activity?
    c. How will we measure performance? What metrics will define and track success?
    d. How will we fund the incremental project without increasing the budget? What resources currently directed to lower priority resources will be redirected toward these higher-priority issues?
    f. As a general rule, activities in this area should not necessitate an increase in budget, and instead should be accommodated through reassignment of resources.

Low-Priority Issues

Description

Generally, these areas can be monitored or put on hold. For those issues where NERC currently has no active efforts, no new activities should be initiated beyond monitoring.

Low Priority Issues	Prevention and Mitigation Controls
Long Term Planning and Modeling: We have an event because our models and forecasts were inaccurate and did not predict the problem we experienced.	Applicable NERC Standards: FAC-008 through -011, -013, -014 MOD-010, -012, -016, -017, -018, -019, -020, -021 PRC-001, -007, -023 TPL-001 through -004
	NERC Standards Development Projects: 2010-03 Modeling Data (Future) 2010-04 Demand Data (Future) 2007-09 Generator Verification
	Other NERC Activities: Reliability assessments PC and subcommittees
	Non-NERC Activities: None identified
Geomagnetic Disturbance (GMD): We have an event because of a Geomagnetic Disturbance. NOTE: Although the RISC has rated GMD a low-priority item from a reliability risk perspective, this item may change in priority and/or need additional ERO resources allocated, based on future discussions or regulatory directives	Applicable NERC Standards: None specifically address this issue EOP-001, -005, -006, -008, -009 address generically
	NERC Standards Development Projects: Future.
	Other NERC Activities: ESISAC GMD Task Force OC Review of Operating Practices

Low Priority Issues	Prevention and Mitigation Controls
	Non-NERC Activities: Government agencies: Monitoring, Satellite Forecasting Entities: Emergency Procedures, Studies, Disaster Recovery, Blackstart Plans EEI: Spare Transformer Database
Transmission Right of Way: We have an event due to a forced outage of part of the transmission system caused by a right-of-way incursion.	Applicable NERC Standards: FAC-003, -008 TPL-001 through -004
	NERC Standards Development Projects: None
	Other NERC Activities: The FAC-008 Ratings Alert Transmission Availability Data System
	Non-NERC Activities: Vendors: LiDar and New Technology, Flyovers Public: Customer Reporting Entities: Vegetation Management Programs, Loops, Protection and Control systems
Climate Change, Environmental Regulations, Changing Resource Mix due to Environmental or Other Market Conditions, Integration of Variable Generation: We have an event due to vulnerabilities associated with climate, environmental, or market concerns.	Applicable NERC Standards: None specifically address this issue
	NERC Standards Development Projects: None
	Other NERC Activities: NERC Reliability Assessments OC, PC, and associated Subcommittees

Low Priority Issues	Prevention and Mitigation Controls
	Non-NERC Activities: Local Government: Resource Adequacy Provisions Entities: Regulatory Communications and Lobbying, Awareness and Studies Vendors: Conferences ISOs and RTOs: Market designs
Generation Resource Adequacy: We have an event due to a lack of Resource Adequacy (not enough generation built).	Applicable NERC Standards: None specifically address this issue BAL-001, -002 address generically PRC-006 through -011 address generically
	NERC Standards Development Projects: None
	Other NERC Activities: Long term assessments and Reserve Margins
	Non-NERC Activities: Balancing Authorities and Market Operators: Market and System Operator Procedures, Generator Commitments and Planned Reserves Local Government: Resource Adequacy Provisions
Extreme Weather/Acts of Nature: We have an event caused by a hurricane, flood, earthquake, etc…	Applicable NERC Standards: None specifically address this issue EOP-001, -005, -006, -008, -009 address generically
	NERC Standards Development Projects: 2013-01 Cold Weather Preparedness
	Other NERC Activities: Monitoring
	Non-NERC Activities: None identified
Integration of New Technologies: We have an event due to a vulnerability	Applicable NERC Standards: None specifically address this issue

Low Priority Issues	Prevention and Mitigation Controls
related to implementation of a new technology.	NERC Standards Development Projects: None
	Other NERC Activities: HILF Report NERC Reliability Assessments OC, PC, CIPC, associated Subcommittees
	Non-NERC Activities: Local Government: Resource Adequacy Provisions Entities: Regulatory Communications and Lobbying, Awareness and Studies Vendors: Conferences
Demand Response: We have an event due to a vulnerability related to implementation of demand response technologies.	Applicable NERC Standards: MOD-016, -019 through -021
	NERC Standards Development Projects: 2010-04 Demand Data (Future)
	Other NERC Activities: NERC Reliability Assessments OC, PC, CIPC, associated Subcommittees Demand Response Availability Data System
	Non-NERC Activities: Local Government: Resource Adequacy Provisions Entities: Regulatory Communications and Lobbying, Awareness and Studies Vendors: Conferences
Smart Grid: We have an event due to a vulnerability related to implementation of SmartGrid technology.	Applicable NERC Standards: None specifically address this issue
	NERC Standards Development Projects: None

Low Priority Issues	Prevention and Mitigation Controls
	Other NERC Activities: NERC Reliability Assessments OC, PC, CIPC, associated Subcommittees
	Non-NERC Activities: Local Government: Resource Adequacy Provisions Entities: Regulatory Communications and Lobbying, Awareness and Studies Vendors: Conferences Collaboration: North American Synchro-Phasor Initiative
Electro-Magnetic Pulse (EMP): We have an event due to an electro-magnetic pulse attack.	Applicable NERC Standards: None specifically address this issue EOP-001, -00-5, -006, -008, -009 address generically
	NERC Standards Development Projects: None
	Other NERC Activities: ESISAC Monitoring
	Non-NERC Activities: Entities: Emergency Procedures, Studies, Disaster Recovery, Blackstart Plans Federal Government: DHS, etc.
Post-Recession Demand Growth: We have an event due to larger than expected demand growth.	Applicable NERC Standards: None specifically address this issue
	NERC Standards Development Projects: None
	Other NERC Activities: HILF Report NERC Reliability Assessments OC, PC, CIPC, associated Subcommittees

Low Priority Issues	Prevention and Mitigation Controls
	Non-NERC Activities: Local Government: Resource Adequacy Provisions Entities: Regulatory Communications and Lobbying, Awareness and Studies Vendors: Conferences ISOs and RTOs: Market designs
Localized Physical Attack: We have an event caused by a local physical attack.	Applicable NERC Standards: CIP-001 EOP-001, -008 address generically
	NERC Standards Development Projects: None
	Other NERC Activities: ESISAC Monitoring OC, PC, CIPC, and associated Subcommittees Grid Security Conference Grid Security Exercise
	Non-NERC Activities: Entities: Physical Security Programs, Staffed Security Services, Remote Monitoring
Pandemic: We have an event due to loss of key personnel due to pandemic.	Applicable NERC Standards: None specifically address this issue EOP-001, -008 addresses generically
	NERC Standards Development Projects: None

Low Priority Issues	Prevention and Mitigation Controls
	Other NERC Activities: ESISAC Monitoring CIPC Pandemic Report HILF Report OC, PC, CIPC, and associated Subcommittees
	Non-NERC Activities: Federal Government: CDC

Other Activities

Description

Inevitably, there may be issues NERC needs to address outside the prioritization process. Practical improvements, interpretations, responses to regulatory directives, and similar activities may not be accounted for directly in the priorities established above, but may nonetheless be required to be undertaken and completed. Some examples could include:

- Paragraph 81 efforts to streamline and optimize the standards
- Efforts to modify the Standard Processes Manual or Rules of Procedure
- Work associated with any potential directives related to Geomagnetic Disturbances

Recommendations

The RISC recommends that the Board adopt this strategic prioritization and endorse the RISC's continued work on a gap analysis on the high-priority and then the medium-priority issues.

In addition, the RISC recommends that the Board direct NERC to incorporate these priority rankings into the development of ERO business plans, and direct NERC Committees to incorporate these priority rankings into the development of their plans – including empowering committees to stop or defer lower priority work.

We further suggest that the RISC be directed to work with NERC staff and Standing Committee leadership to create a results-driven Reliability Strategy development process that integrates with budget development and overall ERO planning (e.g., Standing Committee planning, department and employee goal setting).

Attachment 1 – Summarized Exercise Results

SUMMARIZED EXERCISE RESULTS		Avg Rank	Low Ct	Medium Ct	High Ct	HML Score	Avg Dollars
1	Cyber Attack	1.00	0	0	14	H	$18.46
2	Workforce Capability and Human Error	2.07	0	0	14	H	$12.77
3	Protection Systems	3.07	0	0	14	H	$12.00
4	Monitoring and Situational Awareness	3.86	0	0	14	H	$11.69
5	Operational Modeling and Model Inputs	6.50	0	13	1	M	$6.58
6	Equipment Maintenance and Management	7.00	1	13	0	M	$6.50
7	Coordinated Attack on Multiple Facilities	7.71	1	13	0	M	$5.04
8	Generator Availability	9.21	4	10	0	M	$3.69
9	Increased dependence on Natural Gas Generation	12.00	8	6	0	M	$3.92
10	Generation Resource Adequacy	11.93	11	3	0	L	$2.03
11	Transmission Right of Way	12.07	12	2	0	L	$2.57
12	Geomagnetic Disturbance (GMD)	12.43	11	3	0	L	$2.62
13	Long Term Planning and Modeling	12.64	10	4	0	L	$2.88
14	Climate Change, Environmental Regs, Changing Resource Mix due to Environmental or Other Market Conditions, Integration of Variable Gen	12.71	11	3	0	L	$2.26
15	Integration of New Technologies	15.86	14	0	0	L	$0.96
16	Extreme Weather/Acts of Nature	16.50	12	2	0	L	$1.69
17	Demand Response	16.71	14	0	0	L	$0.92
18	Localized Physical Attack	16.79	12	2	0	L	$0.69
19	Smart Grid	17.29	14	0	0	L	$0.92
20	Electro-Magnetic Pulse (EMP)	17.50	14	0	0	L	$0.77
21	Post-Recession Demand Growth	18.21	14	0	0	L	$0.76
22	Pandemic	19.93	14	0	0	L	$0.27

Average Rank is based on the mean ranking as provided by the members of the RISC.

Low Ct, Medium Ct, and High Ct show the number of members recommending High, Medium, or Low categories. HML Score indicates the majority consensus of the members of the RISC.

Average Dollars indicates the mean allocation of dollars by the members of the RISC based on an imaginary $100 **total** available for ERO activities. The dollar allocation exercise was used a test to make sure the results were correlated.

Agenda Item 13a
Board of Trustees Meeting
February 7, 2013

Operating Committee Report

Action
None

Operating Committee's (OC) Major Accomplishments for 2012

1. **Reliability Guidelines** – The OC approved two reliability guidelines in 2012:
   a. Reliability Guideline: System Operator Verbal Communications – Current Industry Practices
   b. Reliability Guideline: ACE Diversity Interchange
2. **Event Analysis Subcommittee (EAS)** – The OC approved the EAS's scope at its June 2012 meeting. The EAS and the OC engaged with NERC's Event Analysis (EA) staff to encourage the development of lessons learned from bulk power system (BPS) events. The separation of NERC's investigation team from the event analysis team is viewed very positively, which has led to a more proactive involvement of industry stakeholders in the EA process. In addition, the EAS facilitates the presentation of event reports and lessons learned at each OC meeting.
3. **Enhanced Participation/Engagement of the OC** – The OC, in no small part through the efforts of its members, is providing its time and talents supporting reliability by working on items such as:
   a. Providing comments on the development of two reliability standards: 1) the Cold Weather Preparedness standard authorization request (SAR) and 2) the COM-003-1 (Operating Personnel Communications Protocols).
   b. Analyzing the Arizona-Southern California Outages on September 8, 2011 Report's recommendations and WECC's specific responses. The OC continues its efforts to identify industry-wide reliability gaps.
   c. Developing and commenting on Reliability Guidelines, such as those mentioned above.

OC's Major Initiatives for 2013

1. **EAS** – Following an excellent start-up in 2012, the OC and the EAS will jointly work with NERC's EA program to further enhance the EA process. The EA process documentation will be reviewed, revised, and submitted to the Board for approval in 2013. The OC will continue to work with the EAS and the EA program to enhance the identification and publication of lessons learned and event reports. In addition, the EA program is beginning to develop and analyze event related metrics to identify trends, reliability gaps, and opportunities to industry improvement.
2. **Annual State of Reliability Report** – The OC's Operating Reliability Subcommittee will, in 2013, partner with the Planning Committee's Performance Analysis Subcommittee, to proactively review and develop the post-seasonal assessment sections of NERC's State of Reliability report.

3. **Reliability Issues Steering Committee (RISC)** – The OC provided timely responses to RISC requests in 2012 in its start up phase. In 2013, the OC will look for opportunities to support the maturation of the RISC and develop a mutually beneficial relationship. The OC wants to remain responsive to RISC requests while working its strategic plan.

Background

This report provides a summary of the key activities of the OC and its associated subcommittees in support of the NERC or OC mission and corporate goals. All these activities support the NERC or OC mission and NERC corporate goals. The December 2012 OC meeting minutes are posted at OC December 2012 Meeting Minutes.

- **Draft Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices** —The OC approved the draft Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices for a 45-day posting in accordance with its Charter. Comments are due by February 4, 2013. The drafting team anticipates developing responses to comments and, if needed, a revised guideline prior to the OC's March 2013 meeting.
- **PRC-001 (System Protection Coordination – Requirement 1** — Requirement 1 of PRC-001 states: "Each TOP, BA, and GOP shall be **familiar** with the purpose and limitations of protection system schemes applied in its area." The OC continues to discuss the use of the term "familiar" in Requirement 1 and what or how reliability entities are assuring that they are familiar with … protection system schemes applied in its area. At the December 2012 OC meeting, representatives of FRCC, NPCC, and Entergy informed the OC of initiatives within their areas that help in addressing Requirement 1. The OC will continue its discussion of this subject at its March 2013 meeting.
- **Arizona-Southern California Outages on September 8, 2011 – Causes and Recommendations** — WECC staff provided an overview of its efforts to address the recommendations identified in the September 8, 2011 Arizona-Southern California Outage report. WECC has implemented a dashboard (WECC Dashboard) to track its monthly progress in addressing each of the Southwest Outage report recommendations. The OC continues to work with WECC, NERC staff, and the Regional Entities to identify reliability gaps that could be addressed by revising or developing new reliability standards or by the development of reliability guidelines. The OC has tasked its ORS to consider ways in which the OC can address particular WECC questions and assist the electricity reliability organization (ERO) in broader learning from this event.
- **Balancing Authority Reliability-based Control (BARC) Standard Drafting Team** — The BARC standard drafting team provided a status report of its efforts to develop BAL-001-1 (Real Power Balancing Control Performance), BAL-002-2 (Contingency Reserve for Recovery from a Balancing Contingency Event), BAL-012-1 (Operating Reserve Policy), and BAL-013-1 (Large Loss of Load Performance). With regard to BAL-001-1, the OC requested the BARC standard drafting team to develop a final BAAL field trial report that also identifies lessons learned. In addition, the OC requested that in the event that the ballot for BAL-001 fails that all activity, such as the BAAL field trial, related to development of the BAAL be unwound over a nine-month period. The OC will coordinate such a recommendation with the Standards Committee and the Board to ensure that each entity participating in this multi-year field trial can complete updating relevant processes, capabilities, and system operator training.

Agenda Item 13b
Board of Trustees Meeting
February 7, 2013

Planning Committee Status Report

Action
None

2012 Year in Review
The NERC Planning Committee (PC) had a number of significant accomplishments in 2012 that were aligned with the PC vision and strategic objectives and in support of the ERO's overall reliability mission. The Committee's major accomplishments in 2012, in addition to development of a five-year strategic plan, are summarized below:

- **2012 Long-Term Reliability Assessment (LTRA)**[1] - This annual assessment provides an independent, 10-year view of the reliability of the bulk power system by evaluating key reliability indicators, including peak demand, energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other issues that may impact reliability. Key findings in the 2012 LTRA were: (1) significant fossil-fired generator retirements over next five years, (2) increased risk of capacity deficiencies in ERCOT as planning reserve margins projected to fall below targets, (3) increased dependence on natural gas for electricity generation, (4) long-term generator maintenance outages for environmental retrofits, (5) renewable resource additions introduce new planning and operational challenges, and (6) resources sufficient to meet reliability targets in most areas.
- **2012 State of Reliability Report**[2] – Released in May 2012, the report reviews and assesses the state of reliability based on trends identified through data combined with root cause analysis of events. This report is a follow-on to the 2011 foundational report and represents NERC's integrated view of ongoing bulk power system reliability trends. The report assesses 18 metrics that address the characteristics of an adequate level of reliability, including industry-wide automatic transmission and generating outage rates from 2008 to 2011. Analysis of system frequency response, 2011 demand response availability, event analysis trends, and post summer operations are also highlighted.
- **2012 Frequency Response Initiative Report**[3] – NERC launched the Frequency Response Initiative in 2010 to comprehensively address the issues related to system frequency response following loss of generation. In addition to coordinating the myriad of efforts underway in standards development and performance analysis, the initiative included performing in-depth analysis of interconnection-wide frequency response to achieve a better understanding of the factors influencing frequency performance across North America. This report provided an overview of the work that has been done to -date towards gaining understanding of frequency response, and in support of the standards development effort associated with Standards Project 2007-12 Frequency Response, which is preparing a revised draft standard (BAL-003-1). That standard is intended to codify a Frequency Response Obligation and means for measuring the performance of

[1] http://www.nerc.com/files/2012_LTRA_FINAL.pdf
[2] http://www.nerc.com/files/2012_SOR.pdf
[3] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

Balancing Authorities. In 2012, the PC and the NERC Board of Trustees (Board) reviewed and accepted the results of this effort, completing an important chapter in NERC's research and development activities.

- **Effects of Geomagnetic Disturbances (GMD) on the Bulk Power System**[4] – In February 2012, NERC released its report on GMD that identified loss of reactive power as the most likely outcome from a severe solar storm centered over North America. Significant losses of reactive power could lead to voltage instability and, if not identified and managed appropriately, power system voltage collapse could occur. While loss of reactive power was found to be the most likely outcome from a severe solar storm, the GMD Task Force also assessed the vulnerability of high-voltage transformers to damage. While some transformer types were found to be at risk from geomagnetically induced currents, they tended to be transformers with certain design characteristics that increased their vulnerability, or were transformers nearing their end-of-life. This report, developed in collaboration with government and private industry expertise in power system engineering, space science, geology, and equipment manufacturers, represented a significant advancement in understanding the underlying causes and effects of severe solar storms on the reliability of the bulk power system.
- **Section 1600 Data Requests for Industry Response** – In 2012, the PC approved, along with the Board, three separate Section 1600 data requests to continue support of the NERC reliability mission: one data request in support of FERC Order 754 and two data requests in support of continued enhancement of the Transmission Availability Data System (TADS).

2013 Outlook

There are four key deliverables, in addition to the committee's annual assessments, that will be the focus of the PC in 2013.

- **Assessment of Bulk Electric System Definition Thresholds Report** – This report will address a request received in March 2012 from the Definition of the Bulk Electric System Standard Drafting Team (DBES SDT) to review four technical thresholds in the Phase I Bulk Electric System Definition filing to FERC under Docket RM12-7: (1) the 100 kV bright-line threshold as referred to as the "Core Definition", (2) the 20/75 MVA Generator thresholds identified in Inclusions I2 and I4, (3) the allowable Power Flow out of Local Networks and (4) the Reactive Power Sizing threshold. The PC is expected to finalize this report in late January 2013.
- **Natural Gas and Electric Interdependency Phase II Report** – With a primer (Phase I) developed and risks identified, the Phase II study is expected to identify specific vulnerabilities that can affect reliability as more gas-fired capacity is integrated into the bulk power system. NERC will use the Phase I report as a platform to begin discussions with the gas industry on how to resolve the many issues identified. Many of these discussions are already ongoing between NERC and the North American Energy Standards Board (NAESB), the Natural Gas Supply Association (NGSA), and the Interstate Natural Gas Association of America (INGAA). Recommendations from this report are expected to provide input to foster change in the areas of gas infrastructure planning, contracting and tariff practices, market and regulatory rules, and power system planning

[4] http://www.nerc.com/files/2012GMD.pdf

and operations. This report is expected to be completed in late February 2013 and submitted to the Board in late March 2013.

- **Assessment Reports** – The PC expects to submit on-time deliveries of four assessment reports to the Board for their consideration. Three reports are statutorily identified in the NERC Rules of Procedure, Section 800: (1) Long-Term Reliability Assessment and (2) two seasonal look-ahead reliability assessments of the summer and winter operating periods. The PC will also submit in Q2 2013 the next iteration of the State of Reliability Report that reviews the performance of the bulk power system and identifies key trends in the operation of the bulk power system in 2012.
- **Continued support of NERC Standards Development Process** – The PC continues to support the NERC Standards Development process with Subcommittees of the PC conducting essential research into current and proposed areas of reliability issues to either highlight on-going issues or improve the industry's body of knowledge relating to system planning and reliable operation of the bulk power system. Currently, the PC is developing responses to 13 separate Requests for Research by the Standards Committee.
- **Southwest Outage Followup** – The PC is continuing to support NERC's efforts in responding to the recommendations from the Southwest Outage report.

Additional Background

The last Planning Committee meeting was held in December 2012 in Atlanta, GA. The draft minutes are posted at Meeting Minutes.

Key items addressed at the December 2012 meeting were:

- Approval of Section 1600 data request for the Transmission Availability Data System (TADS)[5]
- Approval of Recommendations to be sent to the Definition of the Bulk Electric System Standard Drafting Team
- Approval of a new NASPI / PC Subcommittee focused on SynchroPhasor Measurement

Future Meetings

The PC future meetings are scheduled as follows:

- March 5-6, 2013 – Albuquerque, New Mexico
- June 11-12, 2013 – To Be Determined
- September 17-18, 2013 – Denver, Colorado
- December 10-11, 2013 – Atlanta, GA

[5] Follow on Request Letter: http://www.nerc.com/docs/pc/tadswg/Section_1600_Data_Request_Letter_DRAFT_TADS_100-199kv_12-15-11_mm.pdf

Agenda Item 13c
Board of Trustees Meeting
February 7, 2013

Critical Infrastructure Protection Committee Report

Action
None

Background
In 2012, the Critical Infrastructure Protection Committee (CIPC) Executive Committee conducted a comprehensive review of work activities and deliverables the CIPC Subcommittees would produce and developed a CIPC work plan as a guide for members. The Electricity Sub-Sector Coordinating Council (ESCC) endorsed the CIPC Strategic Plan followed by NERC Board of Trustees approval. The CIPC Strategic Plan outlines the Committee's commitment to the reliability of the bulk power system and to advance the physical and cyber security posture of critical electricity infrastructure of North America. CIPC fosters information sharing, provides industry leadership, and a forum to exchange ideas pertaining to CIP security. The CIPC Executive Committee met in January 2013 to update their Strategic Plan and associated Work Plan. Below is a summary of the CIPC's significant accomplishments in 2012 and the top goals for 2013.

Top CIPC Achievements for 2012

- **Reorganization of the CIP Committee** — Reorganization of the CIPC ran ahead of schedule. Most of the new task forces and working groups slated for startup in 2012 and 2013 have already been formed. New groups such as the Grid Exercise Working Group (GEWG) and the Compliance Enforcement and Input Working Group (CEIWG) slated for 2013 were formed early in response to the industry's need.
  - New subcommittee structures were established to clarify roles and accountabilities
  - Eleven new task forces and working groups chartered and active in 2012
  - Over 150 industry experts were involved in the task forces and working groups, some attracting 20-30 volunteers each
  - Updated CIPC organizational chart attached

Four Task Force Efforts Completed in 2012
Four CIPC task forces completed their assignments in 2012 and have been dissolved.

HILF Implementation Task Force (HITF)	The HITF set the performance standard in 2012 that all future CIPC task forces will be encouraged to follow. This TF started and finished all within the 2012 calendar year. The TF was formed to review the recommendations coming out of the four Coordinated Action Plan reports and provide feedback on the CIP related recommendations.
Cyber Attack Task Force	Cyber Attack Task Force - Final Report

Protecting Sensitive Information Guideline Task Force	Security Guideline for the Electricity Sector: Protecting Sensitive Information
Physical Security Guideline Task Force	Security Guideline for the Electricity Sector: Physical Security

CIP Related Training Workshops
A well-attended classified briefing was coordinated with the Department of Homeland Security (DHS) and Department of Energy (DOE) to inform industry stakeholders of current trends and cyber threats. In addition to the DHS/DOE classified briefing three other training workshops were offered to attendees at the standing committee meetings:

- March 2012 Cyber Incident Handling
- June 2012 Critical Infrastructure Protection: A Public-Private Responsibility
- September 2012 Conducting Successful Cyber Vulnerability Assessments

All three workshops received strong positive feedback from the over 200 attendees.

Top CIPC Goals for 2013

Completion of Currently Active Projects

- Electricity Sector Information Sharing Task Force (ESISTF)
- Personnel Security Clearances Task Force (PSCTF)
- Bulk Electric System Security Metrics Working Group (BESSMWG)
- Physical Response Guideline V3.0 Update Task Force
- Cyber Attack Tree Task Force (CATTF)

Grid Exercise 2013
The Grid Exercise Working Group chaired by Mr. Tim Conway, NIPSCO, will support NERC staff in the development and delivery of Grid Exercise 2013 this fall. Many of the members of this working group were key participants in the original Grid Exercise held in 2011.

Promote NERC ES-ISAC Website Registration and Use
CIPC will continue to promote the use of NERC's ES-ISAC website as the "go to" place for CIP information. Several of the task force efforts underway also reinforce this goal. For example, the ESISTF has been working closely with NERC ES-ISAC staff including an in-person meeting on January 17, 2013 to coordinate on the task force's recommendations/report. The task force is working toward recommendations promoting ES-ISAC as the conduit for information flow between government agencies and the electricity sector.

Other Items of Note

Coordination of CIPC and the Joint OC/PC Event Analysis Working Group (EAWG)
In 2013, CIPC will work through their internal events analysis working groups to form a closer, more formalized association with the EAWG to facilitate a more coordinated approach between

the Operating, Planning, and Critical Infrastructure Protection Committees in the area of event analysis.

2013 Update to the CIPC Strategic Plan, Work Plan, and CIPC Charter

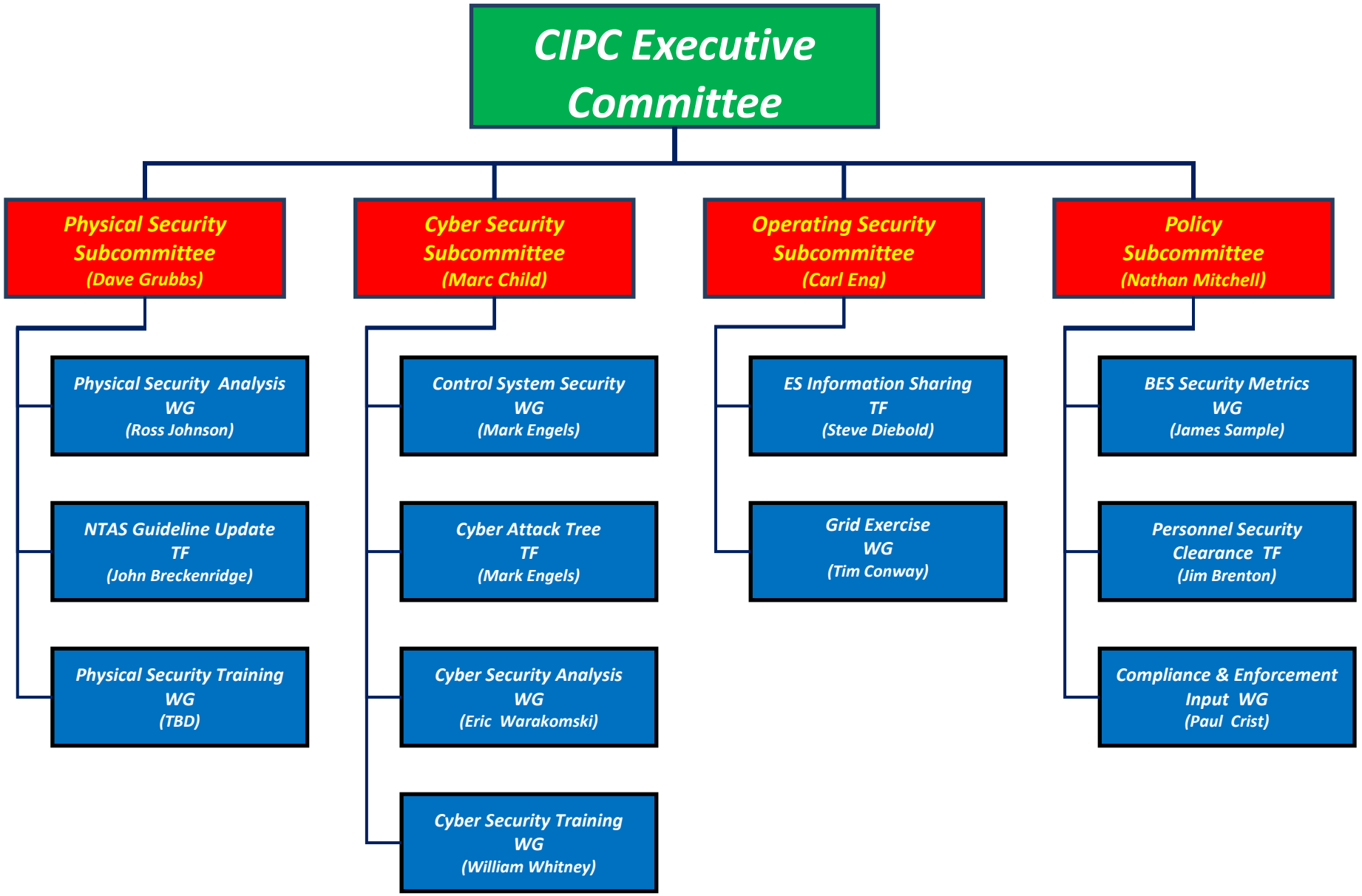
The CIPC Executive Committee met on January 10-11, 2013 to review and update their Strategic Plan, Work Plan, and Charter. Following anticipated approval by the CIPC at the March meetings, they will be submitted to the NERC Board of Trustees at their May meeting.

CIPC Member Changes

The new voting CIPC members are as follows:

- WECC Mike Mertz PNM
- TRE Darrell Klimitchek South Texas Electric Cooperative

CIPC Structure



Agenda Item 13e
Board of Trustees Meeting
February 7, 2013

Personnel Certification Governance Committee Report

Action
None

Background
This report highlights the key activities of the Personnel Certification Governance Committee (PCGC). The PCGC meets four times per year in addition to conducting task force meetings as needed. The meeting minutes are posted on the NERC website.

Summary
Accomplishments
Effective January 1, 2013, the examination fee was reduced from US$700 to US$600. The credential renewal fee was reduced from US$600 to US$300.

The System Operator Certification and Continuing Education Database (SOCCED) Phase 1 upgrade was completed in December 2012 with a production release on January 30, 2013. In addition to the upgrade, a tutorial detailing the new user interface for system operators was posted on the NERC website and linked on the SOCCED log-in page.

Work on SOCCED Phase 2 is scheduled to begin in Februray 2013 with production release set for July 2013.

Future Tasks
To ensure the alignment of the PCGC with Section 600 of the Rules of Procedure, the PCGC completed a review of the PCGC charter in December 2012. No changes were identified as a result of the review.

The Nominating task force is evaluating nominees to fill the two vacancies on the PCGC.

Status Report
NERC Certification Examination Pass Rate
The decline in the overall pass rate for 2012 is reflective of the new exams that were published in February 2012. The table below shows the overall pass rates for 2009 to 2012.

Table 1: Pass Rate

Year	# of Exams Taken	Number of Exams Passed	PASS Percent
2009	1,005	652	64.8 %
2010	914	638	69.8 %
2011	874	607	69.5 %
2012	894	588	65.8 %

Credential Maintenance

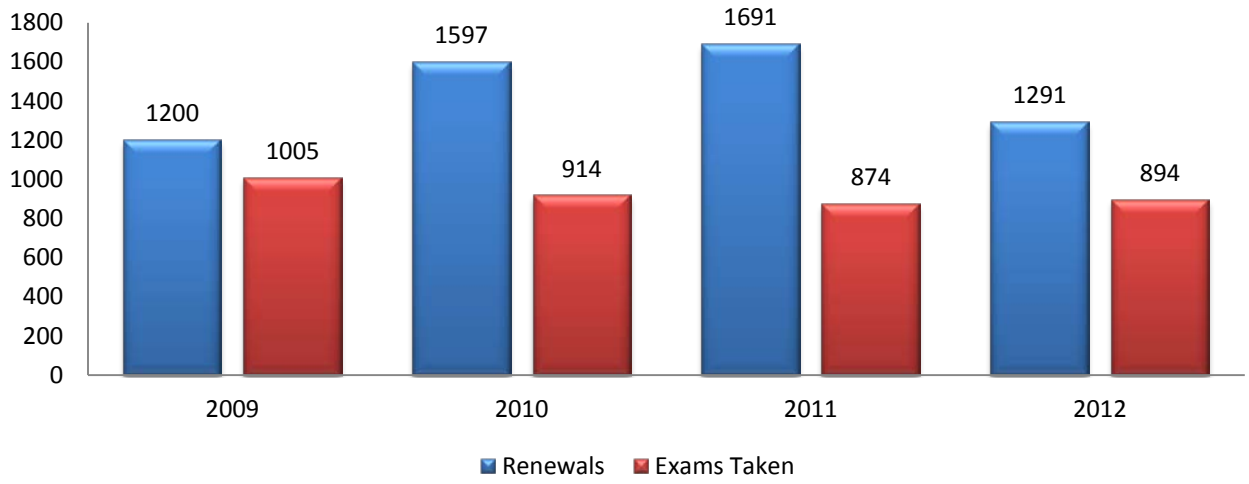
Credential renewal via Continuing Education Hours (CEH) declined in 2012. There was a significant drop in renewals during the fourth quarter of 2012. The reduction of fees effective January 1, 2013 may have affected the overall trend for 2012. Also, the initial certifications (issued in 2006) were on a five-year renewal; thus, the significant number of renewals for 2011. The table below shows the current trend.

Table 2: Certification Renewals via CEHs	
Year	Credentials Renewed
2009	1,200
2010	1,597
2011	1,691
2012	1,291

Exams Taken and Credentials Maintained

The graph below shows the number of exams taken annually is relatively stable while the number of credentials maintained declined in 2012.

Figure 1: Certification Credentials



Certified Operator Population

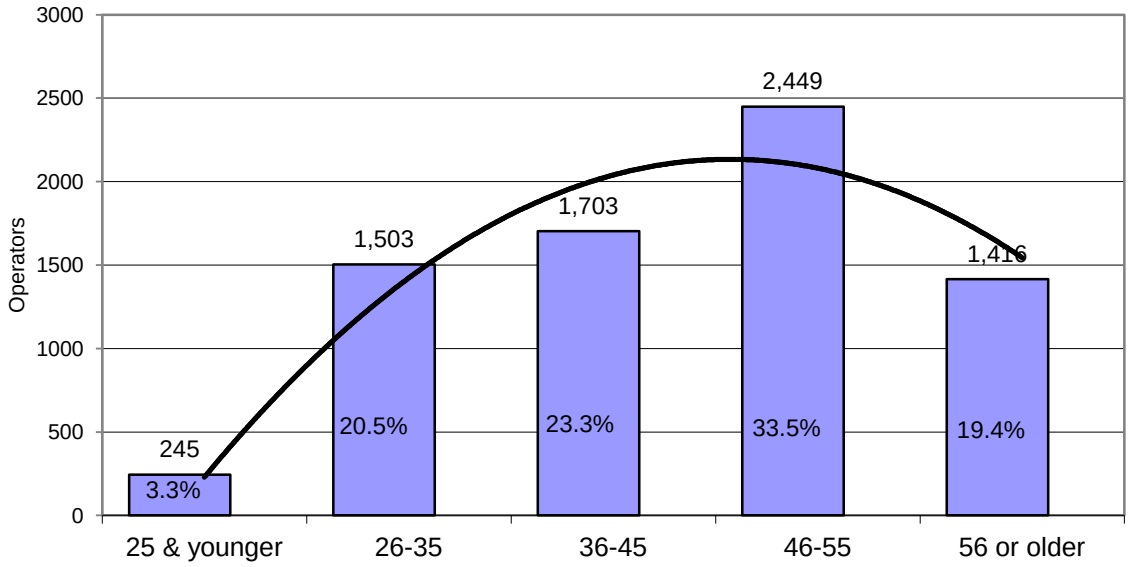
The total number of certified system operators with active credentials is 6,550. The operator population continues to increase slowly.

System Operator Demographics

As of early 2009, system operators have been providing demographic information. This information combines system operators taking their initial exams with those who renewed their credentials through continuing education.

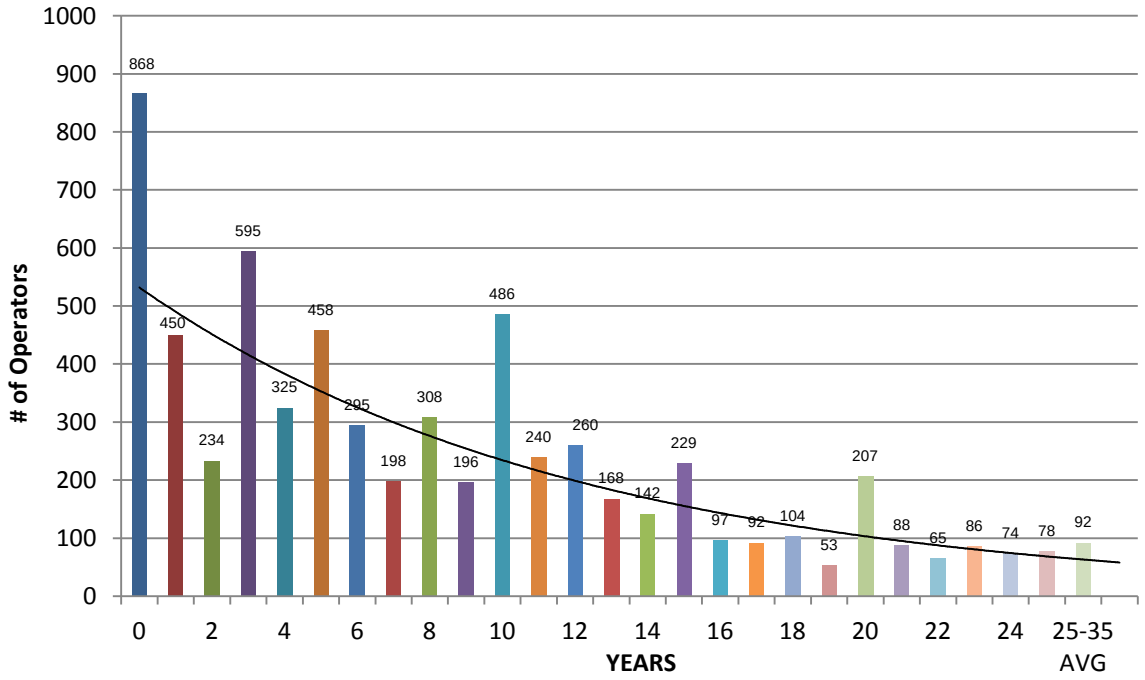
The following figures show current trends that are obtained from the demographics collected, preliminary metrics for average age of system operators and experience in system operations.

Figure 2: Operators by Age Bracket



There has been an increase in the number of system operators for all age groups greater than the age of 25. The largest percentage of system operators remain in the 46-55 age bracket.

Figure 3: Total Experience in Operations



Approximately 69 percent of the certified system operators (which includes non-operating personnel) have 10 years or less experience in system operations. On the average, there has been a slight increase in the number of system operators between five and 10 years of experience.

Agenda Item 13f
Board of Trustees Meeting
February 7, 2013

Standards Committee Report

Action

Approve the following documents and direct that the revised Standard Processes Manual (SPM) (Appendix 3A of the NERC Rules of Procedure) and conforming changes to Section 300 of the NERC Rules of Procedure be filed with regulatory authorities:

- Revisions to the SPM (Appendix 3A of the NERC Rules of Procedure)
- Standards Committee (SC) Strategic Plan
- SC Work Plan
- Revisions to the SC Charter

Background and Summary

In May 2012, the NERC Board of Trustees (Board) approved five recommendations proposed by the Member Representatives Committee's (MRC's) Standards Process Improvement Group (SPIG). Three of these recommendations were delegated to the SC to implement, which resulted in a draft set of revisions to the SPM. The proposed changes to the SPM achieved an affirmative successive ballot outcome of 84.48 percent approval on December 20, 2012. At the time of preparation of these materials, the final 10-day recirculation ballot was still ongoing. An update will be provided at the February 7, 2013 Board meeting. A summary of significant changes reflected in the proposed SPM is included below.

In addition to process improvements made in response to the Board-approved May 2012 SPIG recommendations, and in response to the Board's November 2012 resolution calling for improvements to the reliability standards development process, the SC formed a small group to work with NERC staff to develop a strategic vision for the SC that focused on governance and scope changes to better align the SC's work with the ERO's strategic direction. Based on the work of this group, the SC is recommending additional improvements reflected in the draft SC Strategic Plan, the draft SC Strategic Work Plan, and the proposed SC Charter. These documents are described in further detail, below.

Standard Processes Manual
[Standard Processes Manual-Clean]
[Standard Processes Manual-Redline to Last Approved]

The revisions to the SPM resulted in a streamlined formal process and are consistent with American National Standards Institute (ANSI) Essential Requirements. Specifically, the revisions are:

- Memorialize the intent to revise drafting team composition to ensure they are appropriately equipped to meet reliability objectives (*e.g.*, add attorneys and compliance experts)
- Incorporate reference to compliance assessment tool development, such as Reliability Standard Audit Worksheets (RSAWs), cooperatively and in parallel with standard drafting
- Streamline commenting and balloting, including provisions for:
  - Allowing summary responses to comments and elimination of the obligation to respond in writing at every stage of the comment process
  - Eliminating negative votes without comments in the calculation of consensus
  - Requiring quality reviews to be conducted in parallel with standard development
- Incorporate guidance for the appropriate role and scope of Interpretations, to be consistent with guidance from the NERC Board
- Reduce the requirement for periodic review to be consistent with ANSI minimum requirements
- Incorporate a waiver provision to allow for modifications to the standards development process for good cause, with five-days notice and reporting of the exercise of a waiver to the Board's Standards Oversight and Technology Committee

The revisions were developed by the SC Process Subcommittee and, starting in June 2012, were posted for three stakeholder comment periods, an initial ballot, successive ballot, and a recirculation ballot.

A small number of conforming changes are needed to the NERC Rules of Procedure to reflect the revisions to the SPM. These changes have been posted for stakeholder comment and will be brought to the Board for action at a later date.

A complete development record of the proposed SPM changes is available on the project page.

In addition, several aspects of the SPIG recommendations, such as the recommendation to develop RSAWs concurrently with the development of the associated standards, do not require specific changes to the SPM. Work to implement these recommendations is ongoing.

Standards Committee Strategic Plan and Work Plan

[Standards Committee Strategic Plan]
[Standards Committee Work Plan]

The SC approved a Strategic Plan to align the SC's work with the electric reliability organization's (ERO's) strategic direction, along with a SC Strategic Work Plan that includes specific tasks and milestones for executing the plan, at its January 2013 meeting. The SC Strategic Plan aligns closely with the November 2012 Board resolution and forms the basis for enhancements to the SC's Charter.

The SC Strategic Plan sets forth the vision and mission for the SC. Further, the plan describes the guiding principles, and sets the foundation for refocusing the activities of the SC.

Based on this plan, a companion SC Strategic Work Plan was developed, which is the tactical implementation plan of the SC Strategic Plan. This work plan is meant to be a living document that addresses the current strategic issues facing the SC. The SC Strategic Work Plan covers the period from 2013-2015. To ensure the SC Strategic Work Plan is current and consistent with the SC Strategic Plan, an annual fourth quarter review shall be completed as part of the overall development of the Reliability Standards Development Plan, and updates to the SC Strategic Work Plan will be made as needed.

Standards Committee Charter

[Standards Committee Charter-Clean]
[Standards Committee Charter-Redline to Last Approved]

The proposed enhancements to the SC Charter align the charter with the SC's Strategic Plan and were approved by the SC at its January 2013 meeting. The proposed enhancements include the following duties and responsibilities for the SC:

- Appointment, monitoring, and direction of agile and focused standard drafting teams with subject matter experts that include a facilitator, a technical writer, and compliance, legal, and regulatory experts.
- Coordination with the Reliability Issues Steering Committee to develop a reliability standards development plan that prioritizes and aggressively pursues work that will result in a body of high-quality, results-based standards.
- Establishing and facilitating the informal and formal collaborative, consensus building processes with stakeholder groups and NERC standing, technical and regional committees throughout all stages of reliability standards development.
- Establishing and facilitating the informal and formal collaborative, consensus building processes with stakeholder groups and NERC standing, technical and regional committees throughout all stages of reliability standards development.

- Establishing a quality assurance and quality control for reliability standards that addresses factors, including clarity, completeness, sufficient detail, rational result, auditability and enforceability as well as compatibility with existing reliability standards.
- Sets term limits for the chair and vice chair as well as input from the Board on their selection, and reinforces the SC's accountability to the Board.
- Development of a long-term, multi-year strategic vision that describes the goals and direction for the development of reliability standards consistent with the strategic and business plans of NERC.

Additional Standards Committee Activities

The 2013-2015 Reliability Standards Development Plan, approved by the Board in December 2012, sets a number of ambitious goals for 2013, focused on three main areas:

1. Completion of existing projects and conducting new projects that either support high-risk reliability issues or emerging issues in a timely and efficient manner.
2. Conducting five-year reviews on standards that are due for assessment and have not been revised in recent standards development projects.
3. Addressing remaining outstanding FERC directives and filing the resulting standards with applicable regulatory authorities.

In January 2013, the SC approved several items to support those goals, including appointment of drafting teams and solicitation for volunteer subject matter experts to conduct five-year reviews.

SC agendas and meeting minutes are posted at Meeting Minutes.

Agenda Item 13g
Board of Trustees Meeting
February 6, 2013

Compliance and Certification Committee Report

Action

- Accept the Compliance and Certification Committee (CCC) 2013 Annual Work Plan (included in the agenda package).

Summary

2012 Highlights

- Worked with NERC staff and the Board of Trustees (Board) Finance and Audit Committee to create the Risk Management and Internal Controls Subcommittee (RMICS).
- Provided NERC's Director, Internal Audit and Corporate Risk Management, a spreadsheet of all "electric reliability organization (ERO) shall" references in the Rules of Procedure (ROP) to support NERC's internal monitoring activities.
- Completed all activities in the CCC 2012 Monitoring Plan.
  - Self-certifications for 2011 for:
    - Standards applicable to NERC
    - Conformance to the ROP regarding the Standard Processes Manual (SPM), Compliance Monitoring and Enforcement Program (CMEP), and Organization Registration and Certification Procedure (ORCP)
  - As required in the ROP, assisted the Director, Internal Audit and Corporate Risk Management with a triennial independent audit of the CMEP and ORCP
- Completed the 2012 Stakeholder Perception Survey. Overview and roll out plan appended to this report.
- Assisted NERC staff in drafting changes to Section 500 of the ROP (ORCP).
- Developed the CCC 2013 Annual Work Plan with input from NERC Compliance Operations, Compliance Enforcement, as well as the Board Compliance Committee.

2013 Priorities

- Items requested by the Compliance Committee:
  - Support NERC with its Reliability Assurance Initiative (RAI).
  - Using 2012 survey results, work with Staff on action plans to improve stakeholders' perception of NERC and the Regional Entities on Compliance Monitoring, Enforcement, and Organizational Registration.
  - Continues to provide quality review input on compliance elements and RSAWs, as well as any supporting voluntary compliance trials for new standards.
- Assist NERC in implementing recommendations from the 2012 Independent Audit of the CMEP and ORCP.

- Implement the CCC 2013 Annual Monitoring Plan.
- Support NERC's Internal Monitoring processes as well as the RMICS Mandate and Work Plan.

Upcoming Items

- The next CCC meeting will be March 13-14 at NERC's offices in Atlanta, GA.

Stakeholder Perception Survey

Consistent with its 2012 Annual Plan, the CCC conducted its fourth annual survey measuring stakeholder perceptions on the policies, practices and effectiveness of NERC and Regional Entities with respect to the Compliance, Registration, and Certification programs. The perception survey is intended to be a source of industry feedback to the Board on NERC's and the Regional Entities' effectiveness and performance on these key programs. This periodic review is an essential element of the CCC's Charter.

As requested by the Board, TalentQuest, a respected management consulting firm, was engaged to enhance this year's survey.

The 2012 survey employed both a qualitative and quantitative approach to measure stakeholders' perceptions. Perceptions were measured across six topic areas including: Compliance Monitoring, Enforcement Actions (CMEA), Organization Registration, Organization Certification, Compliance and Reliability Impact, and Other.

The CCC's ERO Monitoring Subcommittee (EROMS) has finalized the survey report. While not yet ready to present to the Board, initial results are encouraging. Industry feedback of NERC and the Regional Entities' strengths included:

- Compliance Monitoring activities involving audit teams, audit processes, and self-certification.
- Progress by NERC and the Regional Entities across all topic areas between 2011 and 2012, with a marked increase in perceptions of NERC around CME Actions.

Improvement opportunities include:

- Communication of clearer, more applicable definitions (in the Bulk Electric System, registrations/registration process, and a valid reliability measure).
- Increased consistency (in processes across Regions (self-certification, registration, etc.), penalty application, and communication between NERC and the Regional Entities).
- Greater efficiencies (in process standardization/timeliness, streamlining, methods of information sharing).

The CCC is giving NERC staff the opportunity to review and comment on the report. Following this review, the CCC suggests the following next steps:

- A WebEx presentation of the survey results by the CCC's EROMS and TalentQuest for appropriate Regional Entity staff (scheduled and managed by NERC).
- CCC approval of the report at its March meeting.
- CCC and NERC staff to develop an action plan to further improve perceptions.
- Present the final report and action plan to the Board at its May 2013 meeting.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC
Compliance and Certification Committee
2013 Work Plan

November 9, 2012

to ensure the reliability of the bulk power system

116-390 Village Blvd., Princeton, NJ 08540
609.452.8060 | 609.452.9550 fax
www.nerc.com

Summary:

The NERC Compliance and Certification Committee (CCC) is a NERC Board-appointed stakeholder committee serving and reporting directly to the NERC Board of Trustees (BOT). The CCC is responsible for engaging with, supporting, and advising the NERC BOT and NERC regarding all facets of the NERC Compliance Monitoring and Enforcement Program (Compliance program), Organization Registration Program (Registration program), and Organization Certification Program (Certification program). The CCC is also responsible for monitoring NERC's conformance to the Reliability Standards development process and those standards applicable to NERC. In order to support this endeavor, the CCC has developed this annual work plan to identify the activities that the CCC intends to perform in 2013 to fulfill the responsibilities the NERC Board has established for the CCC.

Revision History:

Date	Version Number	Comments
10/13/2012	1.0	Initial Draft
10/29/2012	1.1	CCC Balloted Version
11/09/2012	1.1	Approved by CCC

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Purpose

The purpose of this plan is to identify the anticipated activities of the NERC Compliance and Certification Committee (CCC) for the year 2013 and beyond. The plan is based on the responsibilities assigned to the CCC by the NERC Board of Trustees through programs and tasks identified by the CCC required to fulfill these responsibilities.

Introduction

In the capacity of a NERC board-appointed stakeholder committee serving and reporting directly to the NERC board under a NERC board-approved charter[1], and as approved by FERC[2], and as set forth in NERC's Rules of Procedure (RoP), the Compliance and Certification Committee will engage with, support, and advise the NERC board and NERC BOT Compliance Committee regarding all facets of the NERC Compliance Monitoring and Enforcement Program (Compliance program), Organization Registration Program (Registration program) and Organization Certification Program (Certification program). As a committee providing support and advice, but otherwise independent of the execution of these programs, and consistent with prior FERC Orders, the CCC will monitor NERC's compliance with the RoP for these programs on an ongoing basis. In a similar manner, as a committee independent of the NERC Reliability Standards development process, the CCC will monitor NERC's compliance with the RoP regarding the NERC Reliability Standards development process.

The Compliance and Certification Committee provides for balanced discussion, commentary, and recommendations on compliance issues by bringing together a wide diversity of opinions and perspectives from NERC member sector. Members are appointed to the CCC by the NERC Board and serve on the committee at the pleasure of the Board.

Individuals deemed qualified to serve on the committee will generally include senior level industry experts who have particular familiarity, knowledge, and experience in the area of compliance, compliance enforcement, compliance administration and management, organization responsibilities and registration, organization certification, and NERC and Regional standards.

These individuals are normally involved with internal compliance programs within their respective organizations. Committee members are expected to represent the interests of the sector they represent, to the best of their ability and judgment.

CCC Organization

In addition to certain core responsibilities, the CCC has established subcommittees and a working group to perform certain tasks on behalf of and under the supervision of the CCC. Key responsibilities of these subcommittees are outlined below.

[1] http://www.nerc.com/docs/compliance/ccc/CCC_Charter-Feb_2010.pdf
[2] http://www.nerc.com/files/Order_on_Comp_Filing_06.07.2007_CCC_VSL_Order.pdf

Organization Registration and Certification Subcommittee (ORCS)

To fulfill its mission, the CCC has established the Organization Registration and Certification Subcommittee to perform the following tasks on behalf of and under the supervision of the CCC:

1. Advise and provide support to NERC and the Regional Entities with development and implementation of organization registration and certification processes (i.e., RoP 500 & Appendix 5);
2. Advise and provide ongoing support to NERC and the Regional Entities relating to approved organization registration and certification processes;
3. Evaluate the success and effectiveness of NERC and the Regional Entities' administration of the organization registration and certification processes; and
4. Establish programs to monitor NERC's and the Regional Entities' implementation of the organization registration and certification processes.

Standards Interface Subcommittee (SIS)

To fulfill its mission, the CCC has established the Standards Interface Subcommittee to perform the following tasks on behalf of and under the supervision of the CCC:

1. Advise and prepare recommendations to the CCC to address any standard-related issues relevant to and within the scope of the NERC Compliance and Certification Committee (i.e., request from the Standards Committee, Standards Drafting Team, CCC, NERC Compliance Staff, etc);
2. Act as liaison of the CCC to the NERC Standards Committee;
3. Implement CCC oversight, facilitate, and participate as needed in the development of the Compliance Administration Elements (CAEs) for new Reliability Standards under development or for revisions to existing Reliability Standards;
4. Identify personnel to serve on the Compliance Administration Element (CAE) drafting teams as needed;
5. Prepare and maintain guidance and other related documents and materials for the benefit of Standards Drafting Teams regarding the development of CAEs; and
6. Coordinate the CCC quality review responsibilities as established in the Standards Processes Manual.

ERO Monitoring Subcommittee (EROMS)

To fulfill its mission, the CCC has established the ERO Monitoring Subcommittee to perform the following tasks on behalf of and under the supervision of the CCC:

1. Establish and implement programs to monitor NERC's compliance with the Reliability Standards that apply to NERC;
2. Establish and implement programs to monitor NERC's adherence to the RoP regarding the Compliance Monitoring and Enforcement Program as specified in Section 405 of NERC's RoP;

3. Establish and implement programs to monitor NERC's adherence to the RoP regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the standards process as defined in the appeals section of the NERC Standards Processes Manual as specified in Section 405 of NERC's RoP;
4. Develop criteria for use by NERC for the annual evaluation of the goals, tools, and procedures of each Regional Entity compliance enforcement program in the determination of the effectiveness of each Regional Entity program as specified in Section 402.1.2 of NERC's RoP.
5. Develop and implement methods to actively solicit information with respect to stakeholder perception of the procedures, policies, standards, rules, orders, etc., and the effectiveness of the NERC CMEP and Standards Development activities, and provide this information to the CCC and applicable CCC subcommittees. An annual report on stakeholder perception is provided to the NERC board; and
6. EROMS, in 2013, will continue working with NERC staff to implement NERC's *Risk Management and Internal Controls* program.

Procedures Subcommittee (PROCS)

To fulfill its mission, the CCC has established the Procedures Subcommittee to perform the following tasks on behalf of and under the supervision of the CCC:

1. Perform document review to promote consistency between multiple documents (procedures, policies, standards, rules, orders, etc.) that comprise the overall NERC Compliance Monitoring and Enforcement Program (CMEP) and to assure documents are clear, unambiguous, consistent and complementary;
2. Advise the CCC of any such unclear, ambiguous, or inconsistent portions of the CMEP documents and propose changes to the documents that it believes will clarify an unclear, ambiguous, or inconsistent situation; and
3. Develop and maintain CCC operational procedures with respect to the CCC responsibilities under the CCC Charter.

CCC Nominating Committee

The CCC annually appoints a Nominating Subcommittee. The subcommittee consists of five members nominated by the committee chair and approved by the committee. The chair of the subcommittee will be selected by the CCC chair from among the five subcommittee members. Members of the Nominating Subcommittee prepare a slate of committee officer candidates for submission to the NERC Board for approval, and prepare a slate of recommended individuals to fill designated committee vacancies as required.

For the year 2013, the Nominating Committee will continue to identify qualified candidates to submit to the NERC Board for approval for those industry sections that require representation.

Risk-Based Reliability Compliance Working Group

The Risk-Based Reliability Compliance (RBRC) Working Group was established by the CCC in 2011 to support NERC's initiatives related to implementing the concepts of risk-based reliability compliance. In 2012, the RBRC Working Group completed its initial efforts by working with NERC staff to develop a draft template with components and possible criteria that can be used by Registered Entities, NERC and the Regional Entities to conduct an Entity Impact Evaluation (EIE).

The EIE initiative is being re-evaluated by NERC and the Regional Entities to determine next steps with the expectation that the EIE should produce results based on both objective and subjective criteria that can be used to establish a basis for appropriately scoping compliance monitoring for Registered Entities. In 2013, the RBRC Working Group will work with NERC, and the Regional Entities, as requested by NERC, to support the implementation of the EIE template, registered entity internal controls, and other NERC initiatives related to Risk-Based Reliability Compliance.

Key Responsibilities Not Assigned to Subcommittees

In addition to tasks assigned to subcommittees, the CCC, in general caucus, will continue to address certain key responsibilities. These responsibilities include but are not limited to:

1. Provide comments to NERC with respect to stakeholders' perception of the policies, practices, consistency, and effectiveness of the compliance, registration, and certification programs;
2. Recommend revisions to sections 400 and 500 (and their appendices) of the NERC RoP to the NERC Board, and provide comments to the NERC Board regarding the same when revisions are proposed by the Industry or NERC personnel;
3. Establish hearing bodies, as directed by the NERC Board, for any contest regarding findings of, or penalties or sanctions for, violation(s) of Reliability Standard(s) where NERC is directly monitoring the entity for compliance with those standards as described in the NERC RoP Section 409 (Registered Entity by agreement with a Regional Entity or absent a delegation agreement; the Region itself where approved standards are applicable to the Region);
4. Establish hearing bodies with respect to Registered Entities Certification Appeals,
5. Serve as a mediator, as directed by the NERC Board, for any disagreements between NERC and the Regional Entities concerning NERC performance audits of Regional Entities' compliance programs;
6. Participate in Regional Entity compliance program audits that are conducted at least once every five years for each Regional Entity.
7. The CCC will provide a representative to participate on the NERC Reliability Issues Steering Committee (RISC) with the CCC providing expertise and input as requested by said member.

CCC Programs

The CCC has established several programs to fulfill its obligations. These programs include specific monitoring activities such as periodic on-site audits/reviews, NERC Self-Certifications, CCC Spot-Checks, CCC Adverse Finding Investigations, NERC Self-Reporting, Periodic Data Submittals, and CCC Review of Stakeholder Complaints. As resources allow, audits and spot checks may be conducted by independent contractors. The programs are described below.

CCCPP-001: Monitoring Program for NERC's Adherence to NERC's RoP

This program has been established so that the CCC can monitor NERC's adherence to its RoP for Compliance Enforcement. The NERC CCC EROMS will coordinate this effort.

CCCPP-002: Compliance Monitoring Program for Reliability Standards Applicable to NERC

This program has been established so that the CCC can monitor NERC's adherence to NERC Reliability Standards applicable to NERC. The CCC will use a variety of activities to perform the monitoring. The NERC CCC EROMS will coordinate this effort.

CCCPP-003: Monitoring Program for NERC's Standards Processes Manual

This program has been established so that the CCC can monitor NERC's adherence to its RoP concerning Reliability Standards development. The NERC CCC EROMS will coordinate this effort.

CCCPP-007: Monitoring Program for NERC's Adherence to NERC's RoP for Organization Registration and Certification

This program has been established so that the CCC can monitor NERC's adherence to its RoP for Organization Registration and Certification. The NERC CCC ORCS will coordinate this effort.

CCCPP-008: Program for Monitoring Stakeholders' Perceptions of NERC Compliance Program, Registration Program, and Certification Program

This program has been established so that the CCC can gather and report to the Board of Trustees stakeholder perceptions with respect to NERC's CMEP, Organization Registration Program and Certification Program and the way the programs are administered. The NERC CCC EROMS will coordinate this effort.

CCCPP-010: Program for Developing/Reviewing the Criteria for Regional Entity Audits and CMEP Compliance Audits.

This program has been established to identify the criteria by which these audits are conducted, provide a guidance letter to NERC regarding these criteria, and document the process for the CCC to annually review and affirm these for use. The NERC CCC EROMS will coordinate this effort.

2013 Activities for the CCC Programs

In pursuit of its responsibilities, the CCC will mirror the monitoring approaches used by the ERO. To the extent NERC self-reports issues and develops sound internal controls, the approaches to monitoring outlined below will be adjusted.

Self-Certifications

In accordance with CCCPP-001, the EROMS will review and modify (if necessary) the subset of performance items related to the RoP for the CMEP. The CCC will then request that NERC self-certify adherence to RoP for the CMEP, with respect to the subset of performance items, by providing the CCC with a report at its regularly scheduled September 2013 meeting.

In accordance with CCCPP-002, the EROMS will identify the Reliability Standards applicable to NERC. The CCC will then request that NERC self-certify adherence to the Reliability Standards applicable to NERC by providing the CCC with a report at its regularly scheduled September 2013 meeting.

In accordance with CCCPP-003, the SIS will review and modify (if necessary) a subset of performance items related to the NERC Standards Processes Manual. The CCC will then request that NERC self-certify adherence to the NERC Standards Processes Manual, with respect to the subset of performance items, by providing the CCC with a report at its regularly scheduled September 2013 meeting.

In accordance with CCCPP-007, the ORCS will review and modify (if necessary) a subset of performance items related to the RoP for Organization and Registration. The CCC will then request that NERC self-certify adherence to the RoP for Organization Registration and Certification, with respect to the subset of performance items, by providing the CCC with a report at its regularly scheduled September 2013 meeting.

The four reports described above will be in the form of a presentation provided by a NERC officer or equivalent responsible for ensuring adherence to the above identified four elements of the RoP. The presentation will identify adherence to the rules as well as any areas of non-adherence. The CCC will include the results of the self-certifications in these four areas in a report to the Board.

Audits /Reviews

In accordance with CCCPP-001, the CCC will perform an audit/review of NERC's adherence with the RoP for Compliance Monitoring and Enforcement every three years. Additionally, an unscheduled audit/review may be initiated by the CCC if deemed necessary to determine NERC's adherence with the RoP for compliance enforcement or to review deficiencies from

previous audits. The audit/review team will develop a draft audit/review report, review it with NERC, make any necessary changes, and then prepare a final report to be submitted to the CCC. The CCC will review/assess the report and provide NERC a final copy. The CCC will advise the NERC Board of any Adverse Findings and include the results of the audit/review in the report to the Board. An independent audit began in December 2012 and is scheduled for completion in the 1st Quarter 2013. The CCC works closely with NERC to develop audit criteria, participate as observers, and provide expertise to support the independent auditors.

In accordance with CCCPP-002, the CCC will perform an audit/review of NERC's compliance with Reliability Standards applicable to NERC every three years. Additionally, an unscheduled audit/review may be initiated by the CCC, if deemed necessary, to determine NERC's compliance with Reliability Standards. The audit/review team will develop a draft audit/review report, review it with NERC, make any necessary changes, and then prepare a final report to be submitted to the CCC. The CCC will review/assess the report and provide NERC a final copy. The CCC will advise the NERC Board of any Alleged Violations and include the results of the audit/review in the report to the Board. Based on the experience of the 2012 audits, the CCC Executive Team will coordinate with the NERC BOT Risk Management and Controls Subcommittee (RMICS) to determine the use of a third party audit of Reliability Standards in 2013.

In accordance with CCCPP-003, the CCC will perform an audit/review of NERC's adherence with the NERC Standards Processes Manual every three years. Additionally, an unscheduled audit/review may be initiated by the CCC, if deemed necessary, to determine NERC's adherence with the NERC Standards Processes Manual. The audit/review team will develop a draft review report, review it with NERC, make any necessary changes, and then prepare a final report to be submitted to the CCC. The CCC will review/assess the report and provide NERC a final copy. The CCC will advise the NERC Board of any Preliminary Adverse Findings and include the results of the audit/review in the report to the Board. Based on the experience of the 2012 audits, the CCC Executive Team will coordinate with the NERC BOT Risk Management and Controls Subcommittee (RMICS) to determine the use of a third party audit of Reliability Standards development in 2013.

In accordance with CCCPP-007, the CCC will perform an audit/review of NERC's adherence with RoP for Organization Registration and Certification every three years. Additionally, an unscheduled audit/review may be initiated by the CCC, if deemed necessary, to determine NERC's adherence with the Rules of Procedure for Organization Registration and Certification. The audit/review team will develop a draft review report, review it with NERC, make any necessary changes, and then prepare a final report to be submitted to the CCC. The CCC will review/assess the report and provide NERC a final copy. The CCC will advise the NERC Board of any Alleged Adverse Findings and include the results of the audit/review in the report to the Board. An independent audit began in December 2012, and is scheduled for completion in the 1st Quarter 2013. The CCC works closely with NERC to develop audit criteria and participate as observers and provide expertise to support the independent auditors.

In accordance with CCCPP-001, the CCC may initiate an Adverse Finding Investigation, at any time, as directed by the Board of Trustees or based on an event, complaint, or other possible Adverse Finding identified by any other means. Adverse Finding Investigations will follow the processes outlined in a Compliance Program Audit.

In accordance with CCCPP-002, the CCC may initiate a Reliability Standard Compliance Violation Investigation, at any time, as directed by the Board of Trustees or based on an event,

complaint, or other possible violation of a Reliability Standard identified by any other means. Reliability Compliance Violation Investigations will follow the processes outlined in a Compliance Program Audit.

In accordance with CCCPP-003, the CCC may initiate a Standards Development Process Review Investigation, at any time, as directed by the Board of Trustees or in response to a complaint or evidence that NERC has not adhered to the Standards Development Process Procedures. Standards Development Process Review Investigations will follow the processes outlined for a Standards Development Process Review.

In accordance with CCCPP-007, the CCC may initiate an Organization Registration and Certification Investigation as directed by the Board of Trustees, or at any time, in response to a complaint or evidence that NERC has not adhered to the RoP for Organization Registration and Certification. Adverse Finding Investigations will follow the processes outlined for a Registration and Certification Program Audit.

Spot-Checks

In accordance with CCCPP-001, the CCC may from time to time perform spot-checks to determine whether NERC is adhering and/or has adhered to the RoP for Compliance Enforcement. Spot-checking may also be initiated in response to a directive from the Board of Trustees or to events or a complaint. Results of spot checks will be provided to NERC and will be reported to the NERC Board.

In accordance with CCCPP-002, the CCC may from time to time perform spot-checks to determine whether NERC has complied and/or is complying with the Reliability Standards applicable to NERC. Spot-checking may also be initiated in response to events or a complaint. Results of spot-checks will be provided to NERC and will be reported to the NERC Board.

In accordance with CCCPP-003, the CCC may from time to time perform spot-checks to determine whether NERC is adhering and/or has adhered to the Reliability Standards development process. Spot-checking may also be initiated in response to a directive from the Board of Trustees or to events or a complaint. Results of spot-checks will be provided to NERC and will be reported to the NERC Board.

In accordance with CCCPP-007, the CCC may from time to time perform spot-checks to determine whether NERC is adhering and/or has adhered to the RoP for Organization Registration and Certification. Spot-checking may also be initiated in response to a directive from the Board of Trustees or to events or a complaint. Results of spot-checks will be provided to NERC and will be reported to the NERC Board.

The CCC Executive Team will coordinate with the NERC BOT Risk Management and Controls Subcommittee (RMICS) to determine the use of Spot Checks of NERC processes in 2013.

NERC Audits of Regional Entities

A CCC member will participate in each audit of a Regional Entity by NERC. The PROC has developed **CCCPP-010 – Process for Developing/Reviewing the Criteria for Annual Regional Entity Audits and CMEP Compliance Audits**. The deliverables from the implementation of this program identify the criteria by which these audits are to be conducted, a guidance letter to NERC regarding these criteria, and documentation on the process for the CCC

to annually review and affirm these for use. These criteria are extracted from the underlying assumptions contained in the Compliance Process Audit Worksheets applicable to these types of audits and other materials.

Monitoring Stakeholder Perceptions

As stated in the CCC Charter in Section 3, Committee members are expected to represent the interests of the sector they represent, to the best of their ability and judgment. Members are expected to solicit comments and opinions from constituents and groups of constituents, or trade organizations represented by the member and convey them to the CCC. During 2013, committee members will participate in documenting comments to the CCC, with respect to stakeholders' perception of the policies, practices and effectiveness of the CMEP, Registration Program, and Certification Program. The EROMS will lead, direct, and initiate these reviews and surveys of CCC members and provide recommendations for consideration to NERC.

The CCC has developed the Program for Monitoring Stakeholders' Perceptions of NERC CMEP, Registration Program, and Certification Program. An element of this program expected to be carried out in 2013, in addition to obtaining direct feedback from committee members, will include conducting surveys of stakeholders in the second half of the year. Depending upon the level and nature of the feedback gathered, additional elements of the program may include seeking stakeholder feedback in a CCC-sponsored segment contemporaneous with Regional Entity Compliance Workshops or in conjunction with existing stakeholder compliance working groups. Part of the communication provided in advance would include the explanation of the roles/functions of the CCC, the survey elements being considered, and the manner for providing a feedback report to the Board of Trustees and the stakeholders. Additional methods of communicating with stakeholders may include providing information regarding the survey in NERC News and direct e-mails to stakeholders.

An important element of the program will be an annual report, presented to the CCC for approval to forward to NERC, the Board of Trustees, and the stakeholders, as well as quarterly stakeholder perceptions reports to the CCC. Specifically the NERC Board of Trustees Compliance Committee (BOTCC) has asked that the CCC take the lead on analysis of the perception survey responses; refining issue identification; developing possible action plans with industry input; facilitating development of alternatives; and making recommendations to the NERC staff or board.

In addition to the annual perception survey, the CCC will hold a member roundtable at each CCC meeting. During the roundtable, the members are expected to raise issues, observations and concerns of their stakeholders. The CCC will capture issues raised and work with staff to resolve them as they arise.

Longer term activities, beyond 2013, may include mechanisms for the CCC to directly receive feedback from stakeholders following audits and any of the other effectiveness monitoring inputs or evaluations surrounding the effectiveness metrics endorsed in CCCPP-008.

CCC Projects/Subcommittee Activities

Global CCC Projects/Activities

- CCC and subcommittee member Audit Training.
- CCC Member Hearing Training.
- Perform a Self-Assessment of the CCC and its subcommittees by July 2013.
- Develop a 2014 Annual Work Plan by November 2013.
- Review and act (if appropriate) upon reports and recommendations provided by NERC and its other Standing Committees.
- Review and comment on FERC and NERC requests for information and comments.

ORCS Activities

- Review RoP for improvements to the NERC Organization Registration and Organization Certification activities.
- Monitor the Bulk Electric System Definition project to determine if any modifications to Section 500 and the Statement of Compliance Registry Criteria are needed.
- Continue working with NERC to finalize the Summer 2012 posted changes to Section 500 and Appendix 5A for NERC BOT approval in 2013.
- Continue working with NERC to finalize the Certification process templates.
- Support NERC initiatives related to 2011 Southwest Outage Report Recommendations.

EROMS Activities

- Implement the program for Monitoring Stakeholders' Perceptions of the NERC Compliance Program, Registration Program, and Certification Program.
- Review and summarize information received from stakeholders.
- Solicit survey input from the CCC members.
- Develop reports for the CCC.
- Implement surveys, webinars, and conduct workshops as appropriate.
- Review the Self Certifications for (1) Reliability Standards applicable to NERC (2) the Compliance Enforcement Program (3) the Organization Registration and Certification Programs, and (4) the Reliability Standards development activities as set forth in the Standards Processes Manual as set forth in the Rules of Procedure.
- Review the criteria for annual Regional Entity Evaluations and CMEP compliance audits in 2013. Modify program and criteria as necessary.
- Provide a guidance letter to NERC containing relevant criteria for the independent audit of the Organization Registration and Organization Certification Programs.
- Assist NERC Internal Audit staff in establishing its internal monitoring program for those areas under the purview of the CCC.

SIS Activities

- Coordinate Reliability Standards Quality Reviews on behalf of the CCC.
- Review criteria for audit/review of NERC adherence to Standards Processes Manual.

- Undertake a Prioritization exercise on the existing list of pending compliance administration elements, presently including CANs.
- Develop Quality Review criteria for CANs and RSAWs and other compliance administration resources developed by NERC.
- Coordinate CAN quality reviews based upon criteria.

PROCS Activities

- Continue to review and recommend comments for CCC on proposed changes to the Rules of Procedure.
- Review and format new CCC Programs as needed and as resources allow pending future changes to Rules of Procedure.
- Review existing CCC Procedures to support 2013 NERC Internal Audits and CCC oversight (i.e., CCCP005, CCCP006, CCCP008, CCCP009 and CCCP010), and identify any necessary work for 2013 to carry out these CCCPs.
- Assist EROMs in the annual Regional Entity Audit Criteria work.
- Review relationship between NERC's Compliance Enforcement Initiatives and Rules of Procedure.

Risk-Based Reliability Compliance Working Group

- Monitor the implementation of the FFT process and other monitoring and enforcement initiatives and suggest enhancements where appropriate.
- Continue working with NERC and the Regional Entities to develop a template with components and possible criteria that can be used by NERC and the Regions to conduct entity assessments.

Hearing/Mediation Responsibilities

The CCC will conduct hearings as necessary to fulfill its function of serving as the hearing body for any contest between NERC and a Regional Reliability Organization (RRO) or Regional Entity (RE) regarding NERC findings of or penalties or sanctions for violation(s) of Reliability Standard(s) by the RRO or RE as described in the NERC RoP Section 409. Note: The CCC's hearing procedures follow the hearing procedures mandated and approved by jurisdictional authorities for use by NERC and the Regional Entities in the compliance program.

The CCC will conduct hearings as necessary to fulfill its function of serving as a hearing body for any Registered Entity appeal regarding the determination that a Registered Entity is not qualified to be certified to perform the functional activities that require certification by NERC. Note: The Certification Appeal Hearing will be conducted on an expedited basis.

The CCC will conduct mediation activities when requested by the NERC Board.

The CCC hearing and mediation procedures are described in the documents identified below and have been approved by the Federal Energy Regulatory Commission:

- CCCPP-004: CCC Hearing Procedures
- CCCPP-005: CCC Hearing Procedures for Use in Appeals of Certification Matters
- CCCPP-006: CCC Mediation Procedures

Meetings (2013)

CCC quarterly meetings (dates and locations tentative)

- March 13-14, 2013 – Las Vegas, NV
- June 12 - 13, 2013 – To be determined
- September 18-19, 2013 – Atlanta or Member/RE Site
- December 4-5, 2013 – Salt Lake City or Member/RE Site

CCC Subcommittees meet as needed. At a minimum, subcommittees meet the morning of the first day of CCC meetings.

NERC Board of Trustee Assignments

The CCC undertakes assignments from the NERC Board or the Board's Committees related to compliance, organization registration, and organization certification.

The primary Board assignments for 2013 are:

- With the ERO undertaking an initiative to transform compliance monitoring and enforcement to processes that are more focused on the adequacy of internal reliability risk controls, the CCC can assist in this effort by gathering examples of internal and reliability risk controls from Registered Entities, documenting examples of quality programs and providing an update to the BOTCC as well as the NERC board on the state and progress of the industry in this area. CCC support in encouraging the industry to participate in these efforts also would be very helpful. This information will help inform NERC's 12-month report compliance filing on the Compliance Enforcement Initiative, to be submitted in March 2013, in response to the FERC Order of March 15, 2012.
- Continued support of the CCC in the quality review process in standards development and input to Reliability Standards Audit Worksheet (RSAW) development during standards development. The CCC could provide additional assistance by supporting voluntary compliance trials after the NERC board has approved a standard and prior to the mandatory and effective date for such standard. This will provide an opportunity for industry to understand compliance obligations prior to the standard becoming enforceable.

Logistics and Budget Requirements for CCC Activities

Listed below are items identified by the CCC that NERC should take into account with respect to costs NERC will incur concerning CCC activities for 2013-2015.

CCC Quarterly Meetings (Cost to be determined by NERC)
Assumptions: 4 CCC meetings per year,
NERC staff attendance

NERC travel expenses
Hotel (Conference Rooms and Food)

Hearings and Appeals (Cost to be determined by NERC)
Assumptions: 1 hearing or appeal in 2013*
Administrative Law Judge's fee and travel expenses
Hearing refresher training
Transcription costs
Travel expenses
Notes:
The CCC conducted hearing training in 2012. It is recommended that training be deferred until 2014 unless a hearing is requested.
CCC will notify NERC and NERC BOT if additional hearings are expected.

Mediation (Cost to be determined by NERC)
Assumptions: No mediations expected, but noted here as a placeholder
Mediator fee and travel expenses

CCC Program Audits/Review
Assumptions:
Audit/Review Independent Contractor $125,000 annually
Audit periodicity will increase as NERC internalizes monitoring capability, based upon recommendations of independent reviewer.

WebEx/Conference Calls (Cost to be determined by NERC)
Assumptions: 3 CCC/Subcommittees NERC Web-Ex or conference calls quarterly

Stakeholder Perception Survey (Cost to be determined by NERC)
Assumptions: At the request of the NERC BOT, the CCC engaged a professional survey firm to conduct stakeholder perception surveys.

Training (Cost to be determined by NERC)
Assumptions:
Half day of hearing training appended to regular CCC meeting every even year.
5-10 CCC members to attend auditor training annually.
One day of quality review training each year for 15 CCC or subcommittee members each year.

Agenda Item 13h
Board of Trustees Meeting
February 7, 2013

Electricity Sub-Sector Coordinating Council Report

Action
None

Background
This report summarizes key activities of the Electricity Sub-Sector Coordinating Council (ESCC) in support of NERC's mission and corporate goals related to critical infrastructure. The ESCC is chaired by NERC's CEO and includes a NERC Board of Trustees (Board) member, five CEO-level executives appointed by the Member Representatives Committee, the chair of the NERC Critical Infrastructure Protection Committee (CIPC), and NERC's director of Critical Infrastructure Protection. The ESCC fosters and facilitates the development of policy-related initiatives to improve the reliability and resilience of the electricity sector, including physical and cyber security. ESCC open meeting minutes are posted at: ESCC Meeting Minutes.

Summary

Recent ESCC Activities
Since the November 2012 Board meeting, the ESCC:

- Held a Closed conference call on November 27, 2012.
- Scheduled an Open and Closed conference call on January 24, 2013.

Involvement in Government Partnership Initiatives
The ESCC recently discussed a number of initiatives in collaboration with senior government officials.

- **Observations – Impact of Hurricane Sandy on the Bulk Power System.** Mr. Bill Bryan, Deputy Assistant Secretary, Department of Energy, shared his first-hand observations regarding the many challenges faced following Hurricane Sandy. He noted that this event attracted an unprecedented level of direct involvement by senior government officials at all levels; municipal, state, and federal. Mr. Bryan is planning to coordinate further with the affected communities to compile an after-action report and offered to share this report with the ESCC members for their consideration.
- **Policy-Level Severe Emergency Tabletop Exercise.** The ESCC continued discussions regarding the proposed policy-level tabletop exercise intended to help NERC and the industry better understand how they would coordinate with government through a severe emergency causing widespread bulk power system outages lasting weeks or months. As a number of other government-led initiatives with similar objectives are presently underway in the wake of Hurricane Sandy, the ESCC will consider these and decide how these important lessons-learned may be incorporated into relevant policy actions within the NERC Grid Security Exercise (GridEx) in November. NERC will host GridEx II on November 13-14, 2013 which will simulate a coordinated physical and cyber attack on the bulk power system. Day two of this exercise will include an executive table-top exercise that will discuss "policy triggers."

NERC Critical Infrastructure Updates

The ESCC discussed a number of security-related matters, including:

- Recent incidents of advanced persistent cyber malware (i.e., Telvent and Aramco ES-ISAC alerts).
- Status of the Critical Infrastructure Protection Committee (CIPC) Work Plan.
- External affairs update, including a draft Executive Order regarding cybersecurity.
- Results of the October 16-18, 2012 Grid Security Conference (GridSecCon).
- Planning for the 2013 Grid Security Exercise (GridEx 2013).
- Status of Institute of Electrical and Electronics Engineers (IEEE) efforts to develop a protective controls standard to address Aurora vulnerabilities.

Coordinated Action Plan – Phase 2

The ESCC has reviewed the 55 recommendations from the four NERC reports addressing high-impact, low-frequency (HILF) risks and requested NERC staff to continue working with the technical committees to assess the extent to which the recommendations are being considered or implemented by NERC and the industry.

Reliability Issues Steering Committee Review of HILF Risks

The ESCC reviewed the Reliability Issues Steering Committee's prioritization of HILF risks and concluded they are consistent with the ESCC's assessment. The ESCC offered to continue to support the RISC's efforts to monitor evolving HILF risks.

Future ESCC Meetings

Thursday	January 24, 2013	2:00–3:00 p.m. 3:00–4:00 p.m.	CLOSED conference call OPEN conference call
Thursday	April 18, 2013	8:00 a.m.–2:00 p.m. 2:00–3:00 p.m.	CLOSED meeting, Washington DC OPEN conference call
Thursday	July 11, 2013	2:00–3:00 p.m. 3:00–4:00 p.m.	CLOSED conference call OPEN conference call
Thursday	October 3, 2013	8:00 a.m.–2:00 p.m. 2:00–3:00 p.m.	CLOSED meeting, Washington DC OPEN conference call

**All times Eastern

REMG
REGIONAL ENTITY MANAGEMENT GROUP

STACY DOCHODA – FRCC | ED SCHWERDT – NPCC | SCOTT HENRY – SERC | LANE LANFORD – TRE
DAN SKAAR – MRO | TIM GALLAGHER – RFC | RON CIESIEL – SPP | MARK MAHER – WECC

Date: **January 16, 2013**

To: **NERC Board of Trustees**

From: **Stacy Dochoda, REMG Chair**

Subject: **Regional Entity Management Group Report for the February Board Meeting**

Dear Chairman Anderson:

Regional Entity Work Groups
All of the Regional Entities take seriously our need to be as consistent as possible in discharging our delegated responsibilities. A key activity toward meeting this objective is our constant collaboration and interaction with each other and NERC. Below are summaries of recent activities of some of the key multi-Regional groups.

Subgroup: ERO - Enforcement Sanction Mitigation Working Group (ESMWG)
The ESMWG supports the ERO-Compliance and Enforcement Management Group (ECEMG), Regional Compliance and Enforcement Staffs and NERC in developing, evaluating, promoting, endorsing and implementing processes, tools and approaches necessary to ensure a reasonably consistent and an optimally efficient application and administration of all compliance enforcement actions by and among the Regional Entities. The ESMWG meets in person 3 times each year and has periodic conference calls as needed. The ESMWG met at the FRCC offices on January 9 and 10, 2013.

1. Reliability Risk Assessments – In September 2012, the ESMWG began reviewed violation descriptions with accompanying risk assessments to determine the appropriate risk determination and identifying any questions/comments/concerns. The exercise was beneficial in identifying areas for improvement in drafting and driving more robust violation descriptions and risk assessments. Given the success and positive response to the exercise in September, the ESMWG conducted a similar exercise in January 2013. The ESMWG plans to continue reviewing examples and evaluating risk assessments at its meetings in 2013.

2. Federal Entity Violations – Regions discussed the status of federal entity enforcement actions and next steps in processing these violations.

3. Reasonableness of Penalty Determinations— The ESMWG will continue to discuss and analyze penalty determinations to ensure better consistency and common understanding of considerations, relying on the NERC Sanction Guidelines. NERC staff has been asked to provide a demonstration and training on the tools available for penalty calculations at the next ESMWG meeting.

4. Enforcement Process Overview—During each in person meeting, one or two Regions provide an overview of their enforcement process. In January 2013, SPP RE completed the round by presenting its process and MRO began the second round by presenting its process. NERC will be presenting an overview of its enforcement process at the ESMWG meeting scheduled for April 2013. It is

anticipated that this will include a presentation of the NERC enforcement oversight role, as well as the NERC CEA role.

5. Rules of Procedure Changes—Regions discussed the December 20, 2012 FERC order regarding RoP changes, including: Intervention related to ISO/RTO members; Certifying questions to NERC BOTCC in hearing process; Regional appeal of Hearing Body decision; Revised definition of "Confirmed Violation"; Identification of Registered Entity; and 60 day Compliance filing must address streamlined mitigating activities (in line with CEI/FFT filing).

Subgroup: ERO – CIP Compliance Working Group (CCWG)

1. The CCWG met face-to-face at the SPP offices in Little Rock on December 4-5, 2012. Key agenda topics from the meeting include:
    - Audit consistency
    - Overview of Microsoft Cloud Computing initiative as it pertains to control center operations.
    - Proposed 2013 work plan
        1. Proposed work plan has been submitted to the ECEMG.
    - CIP Version 4 and Version 5 transition.
    - Impact of Open Enforcement Actions on the conduct of audits.
    - TFE process revision update
    - Initial discussion on how we deal with certain characteristics of Version 5.

Subgroup: ERO - Compliance Information Management Group (CIMG)

The CIMG is working with NERC to improve the two-way compliance data transfer between NERC and the Regions and to allow for implementation of new business rules defined by other Regional working group efforts. This includes real-time status of violations, Mitigation Plan information, and metadata associated to Regional filings.

Support working groups

A. High priority work items:

1. NERC Enforcement Metrics: *Define data points for metric; data cleansing*
2. Transfer of Assets (in conjunction with the CRWG): *Accommodate the transfer of open enforcement actions from one entity (deregistered entity) to another entity within the Regional systems*
3. Revisions to Appendix 4D: *Implement revisions in Regional systems. Work with NERC to develop or change business rules in the web-services to accommodate changes and streamline the transmittal of TFE data.*

B. Other priority work items:

1. Forms Consistency: *Ensure Regions are collecting the same data and the information submitted to NERC is consistent*
2. Data Cleansing Effort: *Ensure existing data is consistent between CRATS and the Regions' systems*

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C. Future items:

1. BES Exceptions (in conjunction with the CRWG): *Manage data for BES Exception processes through Regional systems*
2. Two-Way Synchronization: *Ability to transmit key "NERC-owned" fields back to the Regions*
3. CEI Phase 2

Subgroup: ERO - Training and Education Group (TEG) input February 2013

The ERO Training and Education Group (TEG) is focused on coordination of training projects and priorities for the ERO and stakeholders, and consistent with the charter, is providing a forum for communication and information exchange among NERC staff and the Regional Entity training representatives. The TEG works to identify opportunities for coordinating training activities and expenses among NERC and Regional Entities.

The TEG is focusing on three primary training needs: auditor training, development of training on reliability standards for both the ERO staff and industry registered entities, and training on industry events lessons learned. Auditor training focus for 2013 includes updating audit team leader training content, supporting auditor workshops, and training associated with the implementation of the Reliability Assurance Initiative. In January, the TEG provided suggestions and feedback on auditor training topics for the upcoming ERO Auditors workshop. The TEG is increasing emphasis on improving collaboration for developing and sharing training materials for selected reliability standards for ERO staff and auditors in 2013. The training materials will be shared with the industry in an efficient manner. Lastly, the TEG will provide input for the development of training for the industry on key lessons learned from events. The purpose is to provide training materials that can be used directly or tailored to individual entity needs to make it easier to conduct training and help prevent events by promoting lessons learned.

Subgroup: ERO-Reliability Assessments and Performance Analysis Group (ERO-RAPA)
Current Activities

1. SPS/RAS Update - ERO RAPA initiated an effort to evaluate alignment of regions' special protection systems (SPS's) and remedial action schemes (RAS's). A draft white paper was presented to the PC in December (by the SPSC and SAMS groups) with approval sought in March 2013. The foundational element of the report is a new proposed definition of an SPS/RAS. While the white paper will ultimately be utilized by a SDT for standard development, the ERO-EMG has directed ERO-RAPA to consider how the report could be leveraged near-term in existing regional procedures.

   The ERO-RPAA team has developed and populated a spreadsheet comparing each regions current SPS characterization to the newly proposed SPS definition. In the most recent meeting, ERO-RAPA reps were asked to provide the top two regional issues with the new SPS definition. Some issues identified:

   - Classification /re-classification of SPSs needed to meet new definition SPS categories
   - Impact of new definition's specific reference to "meeting performance issues identified in NERC standards"
   - New definition will add SPSs in some cases and remove them in others

STACY DOCHODA – FRCC | ED SCHWERDT – NPCC | SCOTT HENRY – SERC | LANE LANFORD – TRE
DAN SKAAR – MRO | TIM GALLAGHER – RFC | RON CIESIEL – SPP | MARK MAHER – WECC

- Redundancy may needed, some cases
- Some schemes used for "operator aid" may need to be classified as an SPS

2. Protection System Misoperations Update – In qtr 4 2012, the regions began reporting to the RE's the total number of protection systems "operations" by voltage level, along with the standard PRC-004 misoperations reporting. This will facilitate the calculation of ALR 4-1; a metric indicating the ratio of misoperations to total operations.

   The ERO-RAPA chair and vice-chair have been active in representing the ERO-RAPA on the topic of protection system misoperations. The vice-chair is currently chair of the protection system misoperations task force (PSMTF) which will be producing a final report in March 2013 with key findings and recommendations on how to reduce misoperation occurrences. The chair recently represented ERO-RAPA at the November 2012 Reliability Issues Information Sharing conference (sponsored by the RISC committee).

3. TADS Proposed Modification – ERO-RAPA has been supportive of proposed modifications to TADS reporting that include (1) 100 – 199 kV components, (2) quarterly reporting and (3) collection of certain inventory data. In its December 2012 meeting, the NERC PC voted to support this recommendation in general, while reducing somewhat the inventory categories to be collected. NERC Board of Trustees approved the modifications endorsed by PC on December 19, 2012.

North American Transmission FORUM

Programs

Practices

The Forum's groups of subject matter experts hold Web meetings each month and write Forum practices.

- Compliance— Internal Controls / Compliance Program
- Continuous Reliability Performance Improvement
- Human Performance / Error Reduction
- Transmission—Nuclear Plant Interface
- Facility Ratings
- Modeling
- Operator Tools
- Operator Training
- Security
- System Protection
- Vegetation Management

Current topics

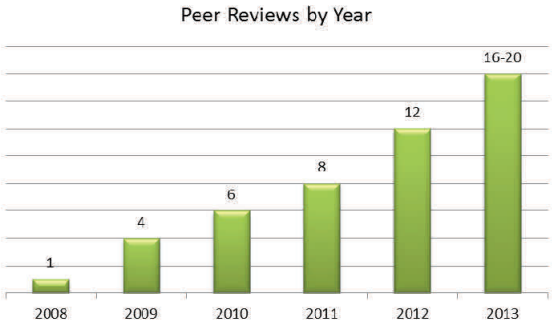
- Physical and cyber security
- Personnel training and implementation of PER-005
- Vegetation management community education
- Modeling—Transmission / generator coordination
- System protection misoperations

Peer Reviews

Forum peer reviews help our members "raise the bar" for their own operations from good to great.

Review teams that comprise subject matter experts in each practice area spend one week at the "host" peer site. The teams' final reports include noteworthy positives and recommendations for the host to foster improvement.

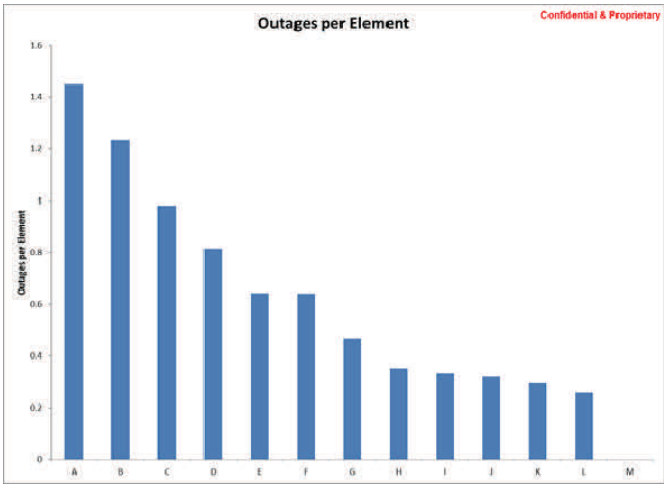
The program will ramp up through 2014 to a schedule in which members will be reviewed approximately every four years. And be evolved to place more emphasis on key practice areas.



Metrics

The Forum collects transmission equipment performance information, such as TADS data. Improving equipment performance directly contributes to improving reliability. The metrics program:

- Allows Forum members to confidentially view other's data
- Provides tools to facilitate peer benchmarking
- Will expand breadth and depth of data collection in 2012



Information Sharing

Forum members readily share information for "lessons learned"

- System event analysis
- Equipment event reports and alerts
- Vegetation contacts
- Surveys on topical subjects
- Case studies
- Members' practices and procedures
- Audit experiences and lessons
- Compliance violations (feedback to Forum practices)

Reliability Initiatives and Assistance

- Initiatives
  - GMD / GIC
  - Facility Rating Alert Follow-up
  - Event follow-up (September 8, 2011; Cold Snap)
- Assistance
  - Human performance error reduction
  - Internal controls / compliance programs

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High Level Actions

Overarching Themes *(Make a positive reliability impact, continuously improve)*

- Raise Forum effectiveness and impact; continuously add value
- Measure progress; aggressively pursue continuous improvement, prioritized on a reliability-risk basis
- Promote candid, constructive peer feedback and accountability as membership-wide norms
- Share information effectively and efficiently – get the right information to the right people for optimum results
- Formalize and strengthen processes in all program areas; ensure effective integration

Practices (*Clarify reliability linkage, identify and export superior practices)*

- Focus practices on the highest priority reliability topics
- Develop and institutionalize principles of operating excellence for each practice area
- Define and disseminate effective and superior practices

Peer Reviews (*Increase formality, focus, and frequency)*

- Conduct rigorous advanced planning, including team selection and associated training
- Systematically communicate key themes to members; increase accountability regarding follow-up
- Incorporate host-member advance self-evaluation as peer review input
- Add focus several key elements including: human error reduction, effective operating experience exchange, and internal controls / continuous performance improvement

Metrics and Information Sharing *(Measure what matters, set high expectations, share key information efficiently)*

- Define relevant reliability metrics with specific improvement goals
- Identify and proactively address adverse trends and precursors to more consequential events
- Foster timely dissemination of lessons learned; facilitate effective member response
- Provide for consolidated member training on key reliability topics

Reliability Initiatives and Assistance *(Innovate while adhering to the mission and vision)*

- Member assistance - provide targeted assistance upon member request to improve in important areas: EMS performance, RTCA, and Vegetation Management / LIDAR
- Reliability Initiatives - assume leadership roles to address selected key reliability challenges including:
  - Member actions on assessment / reconciliation of ROW clearance issues
  - Protection system mis-operations
  - EMS outages

External Interfaces *(Leverage collective wisdom towards reliability improvement)*

- Proactively and routinely interface with FERC, NERC, and others on key reliability issues
- Clarify roles and strengthen working relationships with other industry reliability organizations
- Benchmark relevant organizations from other industries; incorporate findings

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

John Q. Anderson, Chair
Board of Trustees

January 10, 2013

Ms. Carol Chinn, Chair-Elect
NERC Member Representatives Committee

Re: Policy Input to NERC Board of Trustees

Dear Carol:

As part of my last official duties as Chair of the NERC Board of Trustees (Board), I invite the Member Representatives Committee (MRC) to provide policy input on several issues of particular interest to the Board as it prepares for the meetings on February 6-7, 2013 in San Diego. During my tenure as Chair, I have valued and appreciated the thoughtful policy input and active dialog provided by the MRC and the entire body of stakeholders that it represents. I know that Fred Gorbet, as incoming Chair of the Board, will continue to seek the invaluable contributions of the MRC as he assumes his new role.

While the agenda background materials for the Board, committee and MRC meetings are not yet available, I send this request to the MRC to allow for ample time to discuss and formulate input from the respective sectors; input that I anticipate will help shape the course of the ERO in the coming year and beyond.

Standards Reform – In November 2012, the Board approved a resolution that defines the ERO's responsibility to develop clear, high-quality, technically excellent Reliability Standards and supports the ongoing improvement of the efficiency and timeliness of the standards development process. The MRC is encouraged to provide feedback on the sufficiency of the various reform efforts underway, which include, but are not limted to: the restructuring of NERC leadership and staff for standards development; implementation of the recommendations from the Standards Process Input Group; initiation of the Reliability Issues Steering Committee; proposed revisions to the Standard Processes Manual; completion of a new Standards Committee strategic work plan and charter; and development of the 2013-2017 Reliability Standards Development Plan.

Communications Protocols – Based on the balloting outcome of COM-003-1 and the ongoing importance of operator communications to the prevention of and response to system events, the Board is interested in the MRC's input on the anticipated path forward for development of and compliance with standards related to communications protocols. The following is a list of available resources: COM-001-2; COM-002-2a (with interpretation of definition of "directive"); COM-002-3 (not yet filed with FERC); COM-003-1 (the latest version); OC Guideline: System Operator Verbal Communication; FERC Order 693 (Paragraph 540 is the relevant directive for COM-003); 2003 Blackout Report (Recommendation 26 on page 59 of the pdf file is relevant for COM-003 and Order 693 Paragraph 540).

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Reliability Assurance Initiative – In November 2012, the MRC and Board received an initial presentation on the Reliability Assurance Initiative (formally titled Compliance Enforcement Initiative), that outlined an approach to develop an enhanced approach to the ERO's compliance monitoring and enforcement program. Activities to be undertaken as part of the Initiative include the engagement of industry in the development of conceptual white papers that help to describe the attributes and elements necessary to achieve a mature end state for this program. The Board is interested in hearing the MRC's input on the current initiative to include the various change state element papers already underway (Change State Elements), and the recently revised schedule for submitting a filing with FERC.

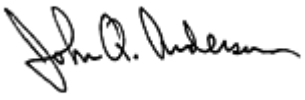
Three-Year Strategic Plan – The advance MRC materials will include the ERO's proposed three-year strategic plan, as well as a copy of the draft criteria that has been developed by NERC management for considering whether an activity should be funded under Federal Power Act Section 215. The MRC is encouraged to provide feedback on both the three-year strategic plan itself, including the goals and deliverables set forth in the plan, as well as the application of the draft Section 215 criteria to the goals and deliverables set forth in the three-year plan.

Bulk Electric System Implementation – FERC Order 773 was issued on December 20, 2012, initiating the implementation of the revised definition of Bulk Electric System. As the standard drafting team continues Phase 2 of the project to provide additional clarity to the definition and resolve technical justification issues, the MRC is asked to share their feedback on the implementation plan, the compliance obligations for newly identified elements, the preparation of databases used to account for assets included in the Bulk Electric System, and anything else that may be of interest regarding this unique project.

Thank you for providing input on these items and any other issues that you believe are meaningful and timely to industry and stakeholders, including discussion of the standards being proposed for Board adoption in the near future. Written comments should be sent to Holly Mann, MRC Secretary (holly.mann@nerc.net) **by January 30, 2013** for the Board to review in advance of the Board and MRC meetings scheduled for San Diego in early February. I understand the agendas for the MRC, Board and committee meetings are expected to be posted by January 23, 2013.

After serving more than 13 years on the NERC Board, I leave with a profound sense of accomplishment and partnership that I share with all of you in the contributions and improvements made to the NERC organization and the ERO as a whole. Thank you for this opportunity.

Sincerely,



John Q. Anderson, Chair
NERC Board of Trustees

cc: NERC Board of Trustees
Member Representatives Committee
Regional Executives

Canadian Electricity Association | Association canadienne de l'électricité

NERC Board of Trustees Policy Input – Canadian Electricity Association
San Diego, California; February 7, 2013

The Canadian Electricity Association ("CEA") appreciates this opportunity to provide policy input for the NERC Member Representatives Committee ("MRC") and Board of Trustees ("Board") meetings in San Diego.

In his January 10, 2013 letter to the MRC Chair-Elect, outgoing Board Chair John Q. Anderson requested stakeholder feedback on specific issues of particular interest to the Board. In these comments, CEA offers its perspective on these issues and also discusses circumstances surrounding a pending standards project which – at the time of writing – could have significant implications for entities in Canada, depending on the ultimate outcome.

Standards Reform

- CEA commends the efforts of all parties who have undertaken a significant work load over the past year to improve the efficiency of the standards development process.

- While CEA is encouraged by the scope and pace of certain efforts (e.g. the early work of the Reliability Issues Steering Committee ["RISC"] and plans for improved project management) concerns remain with respect to other aspects of the reform underway.

- In particular, CEA is wary of procedural reforms that may be at risk of misuse for purposes of unnecessarily accelerating timelines for the development of a given project – whether inadvertently or deliberately. NERC's process should be focused on developing technically-excellent, risk-based and results-based standards aimed at addressing the greatest reliability risks on a timely basis, but not under unreasonably stringent schedules which may invoke the need for efficiency as justification for a truncated timeline – especially when the issue at hand involves questions of significant technical complexity.

- CEA is concerned that reforms such as the inclusion of a waiver provision in the Standards Process Manual ("SPM") and the adoption of a simple (rather than a two-thirds) majority threshold to approve actions of the Standards Committee ("SC") may serve as an opening to efforts which would hastily push a proposed standard through the process and diminish the stakeholder-driven nature of the process.

- CEA maintains that a fundamental objective of the standards process should be achieving a high level of industry consensus in order to deliver a robust standards product. CEA strongly urges the Board to give due consideration to whether proposed reforms such as those cited above may sacrifice the quality of a given standard for the sake of procedural expediency.

Paragraph 81 Project

- CEA remains enthusiastically supportive of the fundamental concept underpinning the P81 initiative – that requirements which are unnecessary, redundant or do little to

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ensure bulk power system reliability ought to be eliminated. CEA strongly urges the Board to approve Phase I of this project at the February meeting.

- CEA wishes to echo concerns voiced by other stakeholders in recent forums, with respect to what appears to be a reduced priority level for the P81 effort going forward.

- CEA shares the view that industry supported a trimmed-down Phase I (which ultimately only proposed to retire 36 requirements) on the understanding that there would be a wider-ranging Phase II effort undertaken upon approval and submittal to governmental authorities of Phase I. While the *Reliability Standards Development Plan: 2013-2015* ("2013 Development Plan") proposes to apply the P81 concept across NERC's major work areas in the coming years, this may not be sufficient to ensure that industry and NERC are taking full advantage of the opportunity presented.

- Expectations are high on the part of governmental authorities for timely success. Accordingly, CEA believes that it is incumbent upon NERC and industry to signal a commitment to achieving progress on this front. Significant work has already been undertaken to identify requirements for retirement and this can readily serve as a basis for subsequent formal phases of activity. CEA encourages NERC to consider options for combining the 2013 Development Plan's proposal for global application of the P81 concept with more concrete measures to deliver results earlier.

Communications Protocols

- CEA welcomes NERC's announcement of a technical conference to be held on February 14-15 to discuss associated concerns and potential paths forward on COM-003-1. CEA appreciates NERC's effort to facilitate movement towards industry consensus in this manner and hopes that such action can be replicated in future standards projects which may arrive at an impasse.

- At the November 2012 meetings, the Board was informed that NERC staff anticipated presenting COM-003 to the Board for adoption at these February meetings, following stakeholder approval. NERC staff also advised that, if COM-003 failed the next round of industry balloting, the Board may wish to determine if an "expedited method" for completing the standard is necessary (i.e. invoking Section 321 of the NERC ROP).

- CEA is not convinced that use of Rule 321 to address COM-003 is justified. While development of COM-003 is in part a response to a directive from FERC Order No. 693 to tighten communications protocols, CEA notes that there is no fixed deadline attached to the directive. In addition, the developmental record shows delays and long stretches of inactivity in the management of the project, certainly not all of which is attributable to the ballot body. What's more, confusion over how this standard would be enforced and how it comports with parallel efforts on other standards (e.g. recently-approved COM-001-2 and COM-002-3) has raised legitimate and serious concerns.

- More broadly, the numerous references in the November 2012 meeting materials to potential use of an "expedited method" for completing a given standards project behoove CEA to reaffirm its general opposition to the use of Rule 321. In authorizing

the Board to direct that a standard be developed outside of the stakeholder process, Rule 321 is wholly inconsistent with the principles underlying the frameworks governing reliability in Canadian jurisdictions.

- Nevertheless, with Rule 321 having been put in place, it is CEA's expectation that the Board will use extreme caution in even contemplating invoking the rule, in view of the significant departure it represents from normal procedures and ANSI principles.

- CEA does not believe that a decision by the Board to direct that modifications to COM-003 be made pursuant to Rule 321 would have been a prudent, fair or acceptable course of action. CEA therefore welcomes this effort by NERC to facilitate movement towards industry consensus, to identify the underlying impediments to achieving such consensus and to explore potential solutions for addressing the root cause of enduring concerns with this proposed standard.

Reliability Assurance Initiative

- CEA applauds NERC's responsiveness to stakeholder input that the original target of March 2013 was too aggressive a deadline to identify and propose for implementation changes to enhance the effectiveness of the ERO's compliance and enforcement program. CEA appreciates NERC's commitment to ensure ample opportunity for stakeholder input as the white papers and accompanying concepts are rolled out.

Three-Year Strategic Plan

- CEA members have not had the opportunity to develop a consensus position on the draft three-year strategic plan posted in the background materials for the February meetings. CEA and its members look forward to the initial discussions in San Diego.

- CEA wishes to briefly comment on one area of NERC activity that attracted much attention in the context of development of the Section 215 criteria – the ES-ISAC.

- CEA has consistently supported NERC having a robust capability, in its capacity as the ES-ISAC, to share timely and actionable information to bulk power system users, owners and operators on security threats and risks. CEA continues to support the ES-ISAC being housed within NERC and supported through normal funding mechanisms.

Bulk Electric System ("BES") Implementation

- Adoption and implementation of a definition for BES will vary across Canadian jurisdictions. Certain jurisdictions may adopt the revised BES definition developed by NERC, while others are pursuing or have already pursued different means (including targeted legislation) to define the scope of facilities to which reliability standards will apply. For example, certain jurisdictions are contemplating adopting an exception process specific to their jurisdiction but equivalent to the NERC exception process (consistent with Sections 1.2 and 1.3 of Appendix 5C of the NERC ROP).

- CEA members are committed to working with NERC, relevant Regional Entities and industry stakeholders to ensure any potential concerns associated with the adoption and implementation of BES definitions in Canadian jurisdictions are addressed.

- In addition, CEA believes that Canadian assets should not be included in the list of facilities exempted from the revised BES definition which NERC is set to prepare and make available, pursuant to the applicable FERC directive. FERC has no jurisdiction over BES facilities or exceptions in Canada. As such, it cannot direct NERC to maintain a list of Canadian facilities which are subject or not subject to reliability standards, nor should any applicable NERC filing to FERC on this matter include any Canadian facilities.

- If NERC opts of its own accord – outside of any compliance obligation to FERC – to maintain an analogous list for Canadian facilities, CEA would hope to have the opportunity to work with NERC on the development of this list and on parameters governing how such information would be made available to applicable governmental authorities in Canada, Regional Entities and "other interested persons."

Other Issue – Project 2010-11 (TPL Table 1 Order)

- CEA wishes to bring to the Board's attention specific concerns that have arisen in the course of this pending project, which is slated for approval in San Diego.

- Project 2010-11 has been re-visited, subsequent to FERC Order No. 762, which remanded a proposed TPL standard to NERC for modification. During the initial ballot, several CEA members expressed strong concern with a sentence in a revised footnote which proposed that planned Firm Demand interruption cannot in any case exceed 75 MW where a single contingency has occurred on a transmission system.

- These CEA members argued that the acceptability of load loss following a contingency, where it does not have widespread impact on the bulk power system, should be the domain of the local jurisdictional authority. They proposed alternative language to the Standard Drafting Team ("SDT") that was initially not accepted. Two members initiated a formal appeal, pursuant to provisions of the SPM, arguing that the SDT failed to adequately address their comments. This appeal was considered during the January 2013 meeting of the SC. SC members approved the suggested re-wording as a substantive change and, subject to SPM requirements, the proposed standard proceeded to a recirculation ballot (open through January 31).

- At the time of submittal of these comments (January 31), the results of the recirculation ballot are not yet known.

- If the proposed standard passes recirculation, CEA strongly urges the Board to approve it. In its previous form, the proposed standard presented an elevated risk of remand by an applicable governmental authority or authorities in Canada, insofar as it imposed an absolute limit on the acceptable amount of non-consequential load loss regardless of the local authority's views. The Board's approval of the change will greatly assist in avoiding the prospects of remand in Canadian jurisdictions – an instance which has yet to come to pass and which CEA sincerely hopes to avert.

- If the proposed standard fails recirculation, CEA and its members will come to the table in San Diego prepared to discuss ways for moving forward on this project.

- CEA appreciates the efforts of the SC, NERC staff and management to settle this matter satisfactorily. Given the prospects of remand down the road in this scenario, CEA believed it worthwhile and appropriate to raise this matter in these comments.

CEA thanks the Board for considering these comments and looks forward to discussing these matters further in San Diego.

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Segment 8 Policy Input to the NERC BOT and MRC – February 7, 2013

The NERC Member Representatives Committee (MRC) Sector 8 representatives (herein "Large Consumers"), supported by the Electricity Consumers Resource Council (ELCON), appreciate the opportunity to respond to the January 10, 2013 letter from NERC Board Chairman John Q. Anderson to Ms. Carol Chinn, Chair-Elect of the NERC MRC requesting policy input on several issues.

At the outset, Large Consumers express their deep appreciation to John Q. Anderson for his many years of service and leadership both as a Trustee and then the Board Chairman. Through Chairman Anderson's leadership, NERC has grown and developed from a voluntary council to the Electric Reliability Organization (ERO) approved by the Federal Energy Regulatory Commission (FERC) that is recognized and respected throughout North America. Thanks Mr. Chairman. You will be missed!

In response to Chairman Anderson's letter, Sector 8 members of the NERC Member Representatives Committee (Occidental Energy Ventures Corp. and Alcoa, Inc., supported by ELCON) offer the following comments:

General Comments: Overall, Large Consumers believe that the volume of NERC materials that are issued, posted, or sent for review and comments are immense – and growing. We strongly urge NERC to focus on reliability and compliance issues that will truly impact the Bulk Electric System (BES).

Second, Large Consumers understand that NERC has been an evolving entity. However, registered entities find it difficult and resource-intensive to attempt to operate under constantly changing conditions. Large Consumers strongly urge the NERC BOT to encourage greater communication and collaboration between NERC and its stakeholders. Having had to fundamentally change direction in its approach to reliability compliance, NERC will need the full support and cooperation of all parties to further develop as a true supporter and guardian of reliability Large Consumers are concerned the recommendations of stakeholders seem to be receiving less recognition by the NERC enterprise

As one example of an area that can use improvement, the amount of time given to stakeholders to respond to the volumes of information issued and posted by the NERC enterprise simply is inadequate. As a specific example, while the John Q. Anderson letter requesting Policy Input is dated January 10th, the MRC and Board agendas were not posted until January 24th with Input due on January 31st – thus giving stakeholders only four business days to develop and file their Input. Stakeholders are not employees of NERC. They have other jobs that often (usually) have higher priority than NERC activities. They simply cannot drop their other responsibilities to respond to NERC requests at any time that NERC specifies. Large Consumers strongly urge NERC to recognize this fact and allocate stakeholders a reasonable amount of time to respond to the various requests for information and response.

Standards Reform – Large Consumers endorsed the standards policy resolution that was approved by the Board of Trustees at its November 2012 meeting. There are a large number of reform efforts now underway or nearing completion including the:

- Restructuring of NERC leadership and staff for standards development,
- Implementation of the recommendations from the Standards Process Input Group (SPIG),
- Approval and initiation of the Reliability Issues Steering Committee (RISC),
- Approval of revisions to the Standard Processes Manual with an 85% majority,
- Completion of a new Standards Committee strategic work plan and charter, and
- Development of the 2013-2017 Reliability Standards Development Plan.

The Standards Committee should be complimented for its very hard work and timely response to the changes. Now these initiatives should all be allowed to move to implementation without further changes in policy direction, scope or governance beyond those presented for Board approval this February.

Large Consumers recognize that NERC has proposed a new strategy that, in essence, replaces Phase 2 of the ¶81 process and may also replace the Find, Fix, Track and Report (FFT) effort as well. Large Consumers support the concept behind the new strategy. They recognize that, if actually accomplished, dealing with ¶81 issues while reviewing other aspects of an open standard is more efficient than dealing with ¶81 issues and other standard issues in a two-step process. However, Large Consumers question whether either NERC or the industry has the resources to deal with nearly 75 open standards, including posting and voting on each in turn, in one year. If the resources are not available, stakeholders may be deprived of the benefits of the ¶81 process rather than finding that the strategy produces more rapid results. Large Consumers urge the BOT to carefully monitor the process to ensure the results in terms of a streamlined set of standards that are more focused on critical reliability activities justify the resource investment.

Large Consumers offer one other cautionary note: Stakeholders do not have either the resources or the desirability to participate in duplicative efforts. While Large Consumers agree that the SPIG can now be disbanded, they are looking with great interest at the scope and output of the RISC. Large Consumers believe that the RISC can serve a very useful purpose by conducting "...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" – as its charter states. However, Large Consumers recognize that it is a fine line between prioritizing specific nominated reliability issues and offering policy input – one of the primary mandates of the MRC.

Communications Protocols – Large Consumers agree that flaws in the communications process have been – and continue to be – a contributing factor for a large fraction of Bulk Electric System outages. It is in everyone's interest to develop reliability standards that ensure the reliable and coherent transfer of information between System Operators.

Large Consumers believe we are on a path of continual improvement that began when COM-001-1 and COM-002-2 took effect on June 18, 2007. Since that time, at least three project

teams have been tasked with addressing the Commission's directives in Order 693, Recommendation 26 from the 2003 Northeast Blackout Report, and stakeholder requests for interpretation.[1]

In general, it seems that the initial iteration of updates has served to consolidate overlapping requirements, eliminated some ambiguities, and added important definitions to the NERC Glossary. One of the most significant was the clarification of the term "Reliability Directive "in COM-002-3 – presently pending approval by FERC. The update provides transparent criteria for an RC, BA, or TOP to determine that a Reliability Directive is necessary – the need for which is captured in the ISO/RTO's request for interpretation.

In another constructive development, COM-002-3 requires that a Reliability Directive must be identified by the issuing entity so that the recipient has no doubt that special caution must be taken during the transaction. Furthermore, the use of three-part protocol is clearly captured in the standard – satisfying Item 3 in FERC Order 693, Paragraph 540 in our estimation. At this point, Large Customers do not have further suggestions for improvements in the communication of Reliability Directives – other than to recommend a continual assessment of the outage data to determine that COM-002-3 is leading to a reduction in communication errors.

The correlation of results back to Reliability Standards will be a continuing theme from this point forward. Up to now, there has been little evidence one way or the other that each NERC requirement has proven to improve reliability. Now with the accumulation of 5+ years of data, we expect the ERO to aggressively remove those requirements which only serve to drive administrative purposes in favor of those which have proven to be effective in reducing BES risk. Large Consumers also believe that wherever possible NERC standards should favor solutions that eliminate human error through automation. The reliability expectations in the face of changes in BES technologies, the deployment of renewables, and rapidly changing load

[1] Specifically: (1) FERC Order 693, Paragraph 540: "While the Commission identified concerns regarding COM-002-2, the proposed Reliability Standard serves an important purpose by requiring users, owners and operators to implement the necessary communications and coordination among entities. Accordingly, the Commission approves Reliability Standard COM-002-2 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to COM-002-2 through the Reliability Standards development process that: (1) expands the applicability to include distribution providers as applicable entities; (2) includes a new Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area view of a transmission operator or balancing authority and (3) requires tightened communications protocols, especially for communications during alerts and emergencies. Alternatively, with respect to this final issue, the ERO may develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26 in the manner described above. Finally, we direct the ERO to include APPA's suggestions to complete the Measures and Levels of Non-Compliance in its modification of COM-002-2 through the Reliability Standards development process." (2) Blackout Recommendation 26: Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate. (3) Request for Interpretation of COM-002-2 R2 by the ISO/RTO Council: Please clarify whether routine operating instructions are "directives" or whether "directives" are limited to actual and anticipated emergency operating conditions.

profiles will be impossible without advanced tools. Requirements which rely on outdated support systems should be discouraged.[2]

While there have been improvements, there are still essential components missing in COM-003-1's requirements addressing non-emergency Operating Instructions. Although there is evidence that mis-conveyed routine instructions are involved in a statistically significant number of outages, it is clear from the industry's low acceptance percentage that most believe the standard does not lead to the right solution. This is despite the fact that the risk-based language "in a manner that identifies, assesses and corrects deficiencies" prefaced the operational requirements – a favorable innovative compliance method.

COM-003-1 may represent an opportunity to encourage the use of existing automation techniques to replace human communication. For example, instead of requiring operators to use phonetic language to identify equipment – NERC may grant an exception for electronic identification through a remote ping or a bar-code reader. Similarly, electronic time-stamps may be used in lieu of oral time-zone communications. The ability to bypass the collection of audit data will be enough to spur most entities to develop these kinds of solutions.

Reliability Assurance Initiative – First, Large Consumers completely support the goals and intent of the Reliability Assurance Initiative (RAI) as we understand it. There is compelling evidence that the original method which relies on the application of sanctions for every violation – no matter how miniscule – does not work. The ERO and the industry have both recognized that such a process creates a massive compliance bottleneck, chasing resolutions to items that pose little risk to the Bulk Electric System.

Large Consumers urge the NERC Board of Trustees to very carefully review the Joint Trade Association comments on the RAI. These comments are supported by a very broad range of stakeholders, including ELCON.

These Joint Comments: support the conclusion drawn in NERC Staff's conceptual White Paper; urge NERC to move ahead with the commitment and support of the regional entities with the second phase of the FFT program; raise concern that insufficient attention has been paid to the development of a clear statement of the impact the RAI will have on registered entities; urge the NERC staff to develop and adhere to a realistic plan for bringing the RAI to fruition; and urge that all regional entities demonstrate their commitment to the goals and consistent application and implementation of the RAI.

While Large Consumers strongly support the concept of the RAI, they are concerned that if not careful, the goals and benefits of both ¶81 and FFT in particular may be lost. Large Consumers'

[2] A positive example of this concept has been incorporated into COM-001-2 and COM-003-1. Although technology types are not limited in any manner, consideration has been given to separate the handling of data and voice communications. By recognizing that three-part protocols do not apply to machine-to-machine or one-to-many broadcast communications, the project teams do not limit the use of those promising services. In addition, it is far easier to obtain execution records from computer systems than from humans – and with a higher level of quality.

initial review of the three RAI white papers is generally positive. The concepts, methods, and intended outcomes align with our expectations of an effective risk-based compliance program. In addition, the level of detail provided at this early stage is appropriate – particularly given the enormity and complexity of the task at hand.[3]

Large Consumers offer two general observations. First, we encourage NERC to resist any inclination to slow down the progress of FFT, ¶81, and other streamlining initiatives while the RAI strategy is being developed. Those programs are far too important to delay for any reason. Rather, Large Consumers recommend that both the ¶81 and FFT initiatives be incorporated into the RAI, not replaced by it.

Secondly, Large Consumers express their concern that the RAI may be attempting too much too fast. Part of this is fear of the unknown, but there is also a legitimate argument to be made that the outcome will be worse than what we have in place today. NERC might want to consider more of an effort to articulate the benefits of the RAI – perhaps through webinars or other media. Such awareness programs should capture the fact that each RAI project will be tested through a voluntary trial before being universally deployed – and that the end result is intended to increase efficiency, not lead to more work.

In sum, the RAI may be the right thing to do, but there are real concerns. Large Consumers strongly urge the Board to carefully monitor the progress of the RAI, in order to ensure that registered entities actually receive the benefits that are promised.

Three-Year Strategic Plan – Large Consumers support the NERC Three-Year Strategic Plan and will work with NERC to establish achievable and measurable ERO and RE performance metrics for the plan. Large Consumers believe this document is a movement in the right direction but more needs to be done. More time and effort must be devoted to this initiative with particular emphasis on metrics that would demonstrate benefits to registered entities. Another area that Large Consumers are especially sensitive to is Goal 7 Coordination and Collaboration. While the goal is well stated, the 2013 metrics limited focus on hiring for a few ERP positions and staying in budget was disappointing.

Bulk Electric System Implementation – Under the Federal Power Act Section 215, the Commission lacks authority to redraft standards, and thereby change the obligations imposed by a Reliability Standard. Nevertheless, Large Consumers feel that FERC's Final Rule did so;

[3] Large Consumers are especially encouraged with the identification of key concepts that are essential to a successful implementation:

- Steps must be taken to reduce the naturally intrusive nature of compliance validation.
- The approach must focus on correcting the behavior of the bad actors, not to punish entities that have made honest mistakes.
- Reliability data must identify those gaps which Compliance must respond to – not those which seem intuitive or reflexively address an event that gathered wide publicity.
- NERC must collect and continually analyze reliability data to determine the effectiveness of its standards – and must move quickly to identify and eliminate those which show little correlation to BES risk.

by reinterpreting the exclusion contrary to its language and NERC's interpretation, the Final Rule revises the BES definition, substantially changing the compliance obligations of registered entities.[4] Changing a Reliability Standard by interpreting it contrary to its terms is not an option available to the Commission under the Section 215 statutory scheme.

During the January 15, 2013 Trades Forum meeting, NERC staff appeared to agree with the unanimous position of the Joint Trades that FERC was attempting to dictate the content of a Reliability Standard. Yet NERC decided not to challenge this issue on either rehearing or clarification.

Although NERC did not challenge FERC's Final Rule, APPA, TAPS & ELCON, NRECA and other entities filed rehearing petitions with FERC opposing its directives. Under the schedule set out in the Final Rule, the new NERC definition of BES and the rest of the new Reliability Standard are to become effective in late February 2015. Further, in late March 2013, NERC is to submit a proposed schedule to FERC setting out NERC's proposed schedule for addressing FERC's directives. Accordingly, a rehearing decision will be issued well before the new NERC Reliability Standard becomes effective and likely before NERC takes any substantive action in response to FERC's directives.

Large Consumers are very concerned that NERC did not defend the ERO's plenary authority to draft reliability standards. There may be good reason for NERC to change its strategy, but such unannounced and unilateral action does not build trust with stakeholders. As a result, we believe that NERC missed an important opportunity to demonstrate its commitment to the separation of authorities in Section 215.

Finally, while Large Consumers understand the need to have a healthy and constructive relationship between NERC and the Commission, we believe in this case the final definition will result in more entities registered for compliance. In the case of large end users, these additional registrations will add costs that will hinder the ability to challenge global competitors while doing very little if anything to improve BES reliability. There is a delicate balance required between FERC jurisdiction, NERC authority and registered entities' responsibilities for an effective reliability effort. Large Consumers strongly believe the ruling failed to achieve the best result.

[4] FERC's December 20, 2012 Final Rule on the BES definition and exception process found that two radial lines above 100 kV connected by a sub-100 kV line are not eligible for Exclusion E1, and that their portions above 100 kV are thus considered BES unless they qualify for Exclusion E3 or are removed through the case-by-case exception process. The Commission ordered modification of Exclusion E3 to remove that exclusion's 100 kV floor to accommodate consideration of configurations with sub-100 kV loops in Exclusion E3. The fact that Exclusion E1 as interpreted by NERC to encompass radial 100 kV lines connected below 100 kV works perfectly with Exclusion E3's limitation to facilities 100 kV and above reinforces the conclusion that the Final Rule's interpretation of Exclusion E1 is inconsistent with the language and structure of the BES definition and amounts to impermissible redrafting of a NERC Reliability Standard.

Electric Power Supply Association
Advocating the power of competition

NERC Board of Trustees
San Diego, California USA
January 31, 2013
Policy Input of the Electric Power Supply Association

On behalf of its member companies, the Electric Power Supply Association ("EPSA")[1] takes this opportunity to provide policy input in advance of the upcoming NERC Member Representatives Committee ("MRC") and Board of Trustees ("BOT") meetings. EPSA appreciates the BOT recognizing value in stakeholders' policy input for the MRC and BOT meetings and how that input can play an important role in informing the BOT leadership on issues impacting the Electric Reliability Organization ("ERO") mission and activities.

In his January 10 letter, BOT Chair John Q. Anderson identified for incoming MRC Chair Carol Chin the items on which the BOT is interested in receiving comments. Herein, EPSA responds to the noted issue areas, with an overall message consistent with past policy input that NERC, as an organization, should be focused on programs and processes that materially support reliability and increase the ERO's efficiency and effectiveness. Program and process development and deployment should be supported by material evidence of their need and value.

Standards Development Process

There is consensus that standards development needs to be improved to produce more timely and effective standards. EPSA looks forward to implementation of the Standards Process Input Group ("SPIG") recommendations; recently balloted revisions to the Standards Process Manual ("SPM") moving forward; completion of the new Standards Committee strategic work plan and charter; and advancing the Reliability Standards Development Plan. EPSA believes that these initiatives should be given sufficient time and opportunity to achieve their goals; any further Standard process changes be held back until these initiatives and plans of the past few months can be put in place, monitored and evaluated.

EPSA supports the Reliability Issues Steering Committee ("RISC") initiatives to prioritize and increase the ERO's efficiency. With respect to the RISC, competitive

[1] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. Competitive suppliers, which, collectively, account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving power markets. Each EPSA member typically operates in four or more NERC regions, and members represent approximately 800 registered entities in the NERC registry. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

suppliers believe that a positive working relationship between the RISC and the Standards Committee should ensure the appropriate alignment for Standards and ERO priorities as decided by the BOT. A thorough, upfront issue evaluation by the RISC will allow for an appropriate assessment as to whether the use of standards is the right tool to address reliability matters. Ideally, relying on the RISC in this way will lead to more targeted standard development projects that focus on creating quality standards in a timely manner.

Reliability Assurance Initiative

EPSA supports the policy input provided by the Trade Associations regarding the Reliability Assurance Initiative ("RAI"), which asserts that the ERO can increase efficiency through consistent and timely application of compliance and enforcement. As expressed in that input, EPSA strongly encourages the ERO in concert with the Regions to move ahead with the goals of the RAI and the second phase of the Find, Fix and Track ("FFT") programs. As provided in FERC's March 2012 Order petition, NERC has the opportunity to bolster the effectiveness of both its compliance and enforcement activities while correspondingly enhancing efficiency. These efficiency and effectiveness gains cannot be achieved by implementation of the FFT initiative Phase 1 alone based on the current data.

Communications

EPSA supports the use of three-part communications as required in approved standard COM-002-3 and draft standard COM-003-1. COM-002-3 requires the use of the three-part communications during emergencies and in response to conditions that may lead to an Adverse Reliability Impact. In contrast, draft COM-003-1 would adopt a more rigorous three-part communications protocol for operating instructions and a programmatic approach to compliance that emphasizes registered entity self-identification and correction of performance deficiencies.

Competitive Suppliers are concerned about how proposed COM-003-1 will be enforced, however. There needs to be agreement on an acceptable set of communications standards and associated compliance elements, as well as what tools will establish that compliance. Consequently, EPSA believes that further clarity is required on how NERC and Regional Entities will assess the quality and implementation of an entity's internal controls.

ERO's Three-Year Strategic Plan

EPSA generally supports the draft ERO Strategic Plan for 2013-2016 and looks forward to working with NERC to establish achievable, measurable ERO and Regional Entity goals and performance metrics to measure the plan. The Strategic Plan should align with NERC's current program activities as well as the criteria for certification as the ERO. Importantly, the draft Strategic Plan does not set clear objectives for communication with stakeholders or the use of the subject matter expertise industry resources.

Bulk Electric System Implementation

Order No. 773 says that Registered Entities are only required to report assets that they have self-determined are no longer part of the BES; they are not required to report assets that remain part of the BES. Chair Anderson's letter discusses "the preparation of databases used to account for assets included in the Bulk Electric System." Order No. 773 does not require Registered Entities to report assets that are "included in the Bulk Electric System." Rather, in Paragraph 317 of the Order it states that Registered Entities have an "obligation to inform the Regional Entity of any self-determination that an element is no longer part of the bulk electric system." Therefore, clarity is needed on Order No. 773 requirements. As described to date, implementation goes beyond the bounds of Order No. 773, representing an inefficient use of ERO and industry resources.

Further, Order No. 773 requires all of a Registered Entity's facilities excluded from the BES to comply with applicable Reliability Standards if those facilities are required for the reliable operation of the Bulk Power System ("BPS"). Two examples are:

- FAC-003-1 (Transmission Vegetation Management Program) applies "to all transmission lines operated to 200 kV and above." The Standard does not address application with respect to whether or not the transmission line is part of the BES. Therefore, self-determined radial exclusion of a 230 kV transmission line could now be subject to the FAC-003-1 if the line is required for the reliable operation of the BPS, per Order No. 773.
- VAR-001-1.b (Generator Operation for Maintaining Network Voltage Schedules) is not specifically limited to BES generators by the standard's language, so this Standard could apply to generators that are below the current 20 MVA threshold if they are required for the reliable operation of the BPS.

EPSA is concerned about how these requirements will be fulfilled as a Registered Entity does not make determinations as to whether its non-BES (excluded) facilities are required for the reliable operation of the BPS. The current implementation plan does not address such facilities. EPSA recommends that the BOT direct NERC staff, coordinating with the Regional Entities, to initiate the development of future modification to the Rules of Procedure to clarify this concern to ensure successful Order No. 773 implementation.

Sincerely,
/s/
Jack Cashin
Director, Regulatory Affairs
Electric Power Supply Association
January 31, 2013

ISO/RTO Council's (IRC) Policy Input to Board of Trustees

January 29, 2013

The ISO/RTO Council appreciates the opportunity to respond to the Board's request for policy input. This document contains policy input on the following areas in response to John Q. Anderson letter dated January 10, 2013, to the Members Representatives Committee (MRC), for the NERC Board of Trustees meeting, February 6-7, 2013:

- Standards Reform
- Reliability Assurance Initiative (RAI) Policy Input
- Communications Protocols

1. Standards Reform

In November 2012, the Board approved a resolution that defines the ERO's responsibility to develop clear, high-quality, technically excellent Reliability Standards and supports the ongoing improvement of the efficiency and timeliness of the standards development process. The MRC is encouraged to provide feedback on the sufficiency of the various reform efforts underway, which include, but are not limited to:

- the restructuring of NERC leadership and staff for standards development;
- implementation of the recommendations from the Standards Process Input Group;
- initiation of the Reliability Issues Steering Committee;
- proposed revisions to the Standard Processes Manual;
- completion of a new Standards Committee strategic work plan and charter; and
- development of the 2013-2017 Reliability Standards Development Plan.

IRC's Input

The IRC generally supports the proposed revision to the SC charter, but is concerned with the following proposed changes :

- *To change the Standards Committee's voting requirement from a super-majority vote (2/3) to a simple majority vote (1/2) can improve decision-making efficiency. We also support retaining the two specific issues presented in the proposed SC charter that require super-majority approval, and would suggest adding two more issues to this list, namely: stopping a standard project and replacing SDT officers since these are also critical decisions that can have major impact on standard projects affecting all segments.*

Regarding the question whether the current Standards Reforms are sufficient, the IRC believes reforms are still needed to address two critical issues:

1. *What is a Reliability Standard*
2. *The basis for enforcement*

Today, every issue is addressed by a new "standard". The Regulators and Industry must come together on what the goal of a Reliability standard is, and how to handle those other industry products, such as guidelines and general practices that are captured into today's standards. The IRC believes that "Reliability Standards" must address defined core reliability issues that impact system reliability and risk to that reliability, i.e. Reliability Standards must be performance and results based. Process and procedure based standards must be avoided because: the procedures themselves are generally short-lived and such standards foster process over reliability; they hinder flexibility; and are often a barrier to innovation. Other current standards such as those that enforce Corporate Practices actually discourage entities from developing more stringent procedures because the failure to meet the entity's more stringent procedures over and above the basic NERC standards requirements must be reported and penalized.

Casual event reporting, that could otherwise be used to alert other entities of pending issues is discouraged because of the concern about Potential Violation investigations.

The IRC supports an enforcement reform to change from assessing and penalizing every violation of every requirement (whether or not the violation had any impact at all on the BES) to enforcement based on a measurable increase in risk or impact to the system (i.e. if there is a measured increase in risk or impact, then enforcement entities can investigate and they can decide, based on the specific circumstances, whether or not to proceed with further actions). This change will reduce workloads on both the entities and the regulators, and reduce the drawn out debates over terminology and place reliability back into the focus of our Industry.

The IRC supports ERO's restructuring and reorganization as a corporate initiative to achieve effective management of work that enhances reliability. The IRC is compelled to point out that the goal of that restructuring should be the reliability of the Bulk Power Transmission system and not just more rapid standards development.

The IRC believes it is an oversimplification to state that "Standards are not being approved" The statement implies that the delays in developing and passing standards are caused primarily by the balloting body. Between 2008 through January 2013, the set of standards has nearly tripled in size. In 2008, the standards spanned slightly over 600 pages. As of January 2013, the book is 1649 pages and the NERC website shows 30 industry-approved projects in queue waiting action by the NERC or FERC. There are standards that have been approved by the Industry but not filed. There have been standards that were approved by the Industry and not forwarded to the BOT. The IRC suggests that the BOT direct staff to expedite submission of Industry approved standards to the BOT for adoption and filing with the regulators.

NERC efforts in distributing information and sharing Best Practices must come from actions outside of enforceable standards. NERC's role as a learning organization must come from sharing ideas (e.g. Operating Guidelines such as the ones developed by the NERC Operating Committee on operator communication and generator preparedness for cold weather) and not simply enforcing procedures.

Reorganization of the ERO must go beyond standard development, and focus on the core issue of Reliability Based Standards i.e. the performance and risk management of the BES.

The IRC supports the initiation of the RISC to evaluate emerging reliability issues and to recommend means to address them such as the RISC recommendation to not having to develop reliability standards for location-specific issues (e.g. Preparedness for cold weather). -That example goes to the heart of the IRC's belief that local issues do not equate to fundamental continent wide BES reliability issues.

The IRC supports the proposed changes to the Standards Process Manual to implement the SPIG's recommendations, and the on-going effort of the SPIG to develop further recommendations as appropriate. However, the IRC suggests that the current changes to the standards development process be allowed the time to demonstrate their effects before implementing yet another set of process changes.

The IRC supports the SC's proposed strategic plan, in particular the setting of a vision and goal to transition to a sustainable set of results-based standards in 5 years through removal of unnecessary requirements.

The IRC offers its support to work in collaboration with other Industry segments and with NERC staff to develop a transition plan to implement the above reforms.

2. Reliability Assurance Initiative (RAI) Policy Input

In November 2012, the MRC and Board received an initial presentation on the Reliability Assurance Initiative (formally titled Compliance Enforcement Initiative), that outlined an approach to develop an enhanced approach to the ERO's compliance monitoring and enforcement program. Activities to be undertaken as part of the Initiative include the engagement of industry in the development of conceptual white papers that help to describe the attributes and elements necessary to achieve a mature end state for this program. The Board is interested in hearing the MRC's input on the current initiative to include the various change state element papers already underway (Change State Elements), and the recently revised schedule for submitting a filing with FERC.

IRC's Input

The IRC appreciates the Board's invitation for the MRC to provide input on the current Reliability Assurance Initiative (formerly titled the Compliance Enforcement Initiative). In summary, the IRC generally supports the policy input provided by the Joint Trade Associations, and respectfully submits the following policy input regarding RAI scope, stakeholder outreach and schedule, and the application of RAI to compliance monitoring and enforcement.

The IRC supports NERC's approach of the development of change state element papers to communicate the underlying details of the RAI. The IRC is unclear on the revised schedule for submitting a file to FERC, except for the delay in the March date. The IRC believes the NERC should make every effort to communicate and coordinate the development and implementation of this new initiative with the industry as noted in various sections below.

A. General Suggestions for the RAI

When the name of this effort was changed from the Compliance Enforcement Initiative, it appeared to some in the IRC that the ERO's intent was for the RAI to be a more encompassing effort – it would align NERC program areas so that ERO and industry resources are better coordinated and focused on identified risks to BES reliability.

Under such a holistic approach, all NERC programs would provide reinforcing support to each other to focus resources on demonstrated risks to the BES. For example, programs such as Events Analysis could help inform Technical Committees' development of guides and reference documents. Where patterns of data show a need, the Standards Development Process would be improved through the ERO managing a data-based approach to developing and prioritizing projects. While the IRC appreciates that this is intended to imbue NERC activities and projects with data regarding demonstrated risks, etc., the IRC respectfully submits that, the simple collection and use of data without meaningful analysis, identification of trends, etc. will not achieve the stated intent of the RAI. More broadly stated, the CMEP and Standards Development Plan should be fact-based. To this end, the IRC requests that the Board consider providing direction that NERC develop its programs so that there is greater reliance on data analysis, trend identification, etc. that is performed with the intent of producing rigorous and comprehensive results that can be utilized to demonstrate and support activities and projects including showing how and why any proposed ERO activity[1] effectively addresses a demonstrated risk.

[1] Such activities could include SARs, priorities in developing Standards, the Actively Monitored List, the proposed schedules for Spot-Checking Standards or requiring Self-Certifications.

Whether NERC remains focused on Compliance through the RAI effort (or expands it as suggested above), the IRC urges NERC to adhere to the commitment it made to FERC, and Industry, in the context of the "Compliance Enforcement Initiative" (the precursor to the RAI) to "develop a deliberate and methodical plan" to involve stakeholders.[2] *The IRC respectfully notes that, in the RAI, NERC has not yet provided Stakeholders with a clear and credible plan for how it would achieve the RAI goals, , the timeline within which it intends to establish and implement RAI activities, and the timeline in which the industry should be prepared to respond to the implementation of the RAI. NERC could greatly facilitate industry "buy-in" to the RAI if it would first focus its discussions with Stakeholders on realistic timelines and implementation plans for RAI program elements.*

B. Suggestions for RAI as Relates to CMEP Program

Most of the RAI work published thus far appears to be limited to new approaches to auditing (and does not discuss other CMEP monitoring tools). Some of the RAI work discusses how NERC and the Regional Entities manage CMEP-related documentation, but that work does not describe how it would benefit or impact the current obligations for both NERC and Regional Entities nor Registered Entities nor does it describe how the proposed activities would modify the actual or potential obligations entities have under the existing CMEP processes. While it appears the goal is to move toward a model that better allocates CMEP-resources to protect BES reliability, few details have been provided on how the RAI might simplify and focus the compliance process and the administration thereof (for all involved entities) -- particularly for minor issues.

With regard to the substance of the RAI, the IRC respectfully recommends that NERC adopt principles to guide its development of CMEP programs to support the RAI. These principles should include:

(A) Match regular assessments of what operating, planning or security issues are presenting the greatest risk to bulk power system reliability to those monitoring tools (Audit, Spot Check, Data submission) most appropriate to efficiently monitor the risks. Such an approach would address Commissioner LaFleur's goals that larger events are prevented by continuously finding and rooting out small problems.

- *The ERO and Industry would identify risks driven by action/omissions among a collective class of Registered Entities (potentially a large, yet unknown risk to BES) as well as the types of risks driven by any particular "individual entity".*

[2] *See North American Electric Reliability Corporation*, Motion for Leave to Answer and Answer of North American Electric Reliability Corporation, RC11-6, at p3 (Nov. 14, 2011)

- *Through effective use of each of the different monitoring tools (e.g., self-certification, spot check), the ERO can increase the amount of monitoring it does of entities' compliance without being overly burdensome to entities.*
- *The ERO should explicitly include in its RAI stakeholder outreach process the topic of how to most appropriately allocate compliance monitoring resources to current assessments of operating, planning or security risks.*

(b) *Move from a zero-defects approach toward supporting a self-correcting, self-reporting, continuous-learning organization. Streamline the front-end of the Enforcement Process so that there is a minimal commitment of resources for Registered Entities for those violations that are ministerial in nature.*[3] *In this regard, NERC needs to move ahead with this second phase of the FFT program at this time, independent of its schedule for developing and implementing the RAI program.*

- *E.g., for CIP-007 and PRC-005 (two standards with large number of ministerial violations), the ERO should develop criteria for when self-reports go to the full NOV, and when they can be disposed of as FFT or Spreadsheet NOPs, or when an entity can track and report to the region the entity's own identification, remediation, and enhanced monitoring of administrative violations at the next audit.*
- *In sum, the IRC respectfully recommends NERC work with the Regional Entities and the Compliance and Certification Committee (CCC) to develop a decision tree or similar job aid that can be used by front line compliance staff to triage and determine the proper initial disposition path of a PV. This should include the authority to document and resolve minor infractions.*

(c) *We recommend that NERC's Reliability Standards Advisory Service (RSAS) group's activities be coordinated with the Compliance & Certification Committee and the Transmission Forum. The RSAS is conducting "pilot programs" providing education on design and development of a Company's Internal Controls (reportedly one of the elements of RAI). If the RSAS coordinates its activities within the overall framework of the RAI, there will be increased likelihood of stakeholder buy-in and support for the overall RAI objectives.*

(d) *We recommend that the RAI initiative should necessarily address initiatives such as the Entity Impact Evaluation and Multi-Regional Registered Entity initiatives as the focus of such initiatives is to ensure the efficient, effective monitoring of Registered Entities.*

[3] The establishment of the spreadsheet NOP and FFT processes were useful enforcement steps. Even so, the value has been limited for the Registered Entities because significant time and resources are still needed to resolve minor infractions. Consider, by contrast, most law enforcement activities, where the front line police officer has the tools, training, and authority to determine the initial disposition path of a potential infraction. The officer can correct the issue on the spot (seat belts), issue a warning ticket (such as when the driver must get a tail lamp fixed), write a ticket (which typically allows for paying a fine with no other proceeding), or arrest the offender. Imagine the efficiency of our justice system if every potential offender needed to be arrested, arraigned, and stand trial or plea bargain. In effect, this is the general model of the ERO Compliance and Enforcement process.

Without a comprehensive, holistic approach, Registered Entities and Regional Entities could potentially be engaging in duplicative and possibly contradictory efforts. For example, having the same Registered Entity submit the same data to two or three Regional Entities, each of which then have to analyze the data, is duplicative and likely provides no benefit to the Bulk Electric System. Additionally, the potential that different Regional Entities may analyze data and derive distinctly different and possibly competing priorities that are then applicable to a Registered Entity operating in both Regions is problematic for both the Registered Entity and the Regions in which it operates and would also and likely provide no benefit to the Bulk Electric System. Accordingly, the RAI effort should encompass these initiatives or otherwise provide how, holistically, they will support the overall CMEP process under RAI.

3. Communications Protocols

Based on the balloting outcome of COM-003-1 and the ongoing importance of operator communications to the prevention of and response to system events, the Board is interested in the MRC's input on the anticipated path forward for development of and compliance with standards related to communications protocols. The following is a list of available resources: COM-001-2; COM-002-2a (with interpretation of definition of "directive"); COM-002-3 (not yet filed with FERC); COM-003-1 (the latest version); OC Guideline: System Operator Verbal Communication; FERC Order 693 (Paragraph 540 is the relevant directive for COM-003); 2003 Blackout Report (Recommendation 26 on page 59 of the pdf file is relevant for COM-003 and Order 693 Paragraph 540).

IRC's Input

The IRC continues to believe that the new versions of COM-001 and COM-002 are improvements that will support an 'Adequate Level of Reliability' and should be filed for approval without further delay.

The IRC also believes that NERC should discontinue any effort associated with COM-003.Industry comments and the results of the recent ballot on COM-003 are indications that industry believes there is no need for COM-003. The combination of revised COM-002, the previous industry approval of the COM-002 interpretation and the now available NERC Operation Committee Reliability Guideline for Verbal Communications is more than sufficient to promote effective communications and meet reliability goals.

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MIDWEST RELIABILITY ORGANIZATION

POLICY INPUT TO NERC BOARD OF TRUSTEES

January 30, 2013

Pursuant to the NERC Board of Trustee's (BOT) request for policy input from the NERC Member Representatives Committee for the upcoming February 6, 2013 meeting, the Midwest Reliability Organization (MRO) Board of Directors respectfully submits the following for consideration by the NERC Board of Trustees.

Standards Reform

In November 2012, the Board approved a resolution that defines the ERO's responsibility to develop clear, high-quality, technically excellent Reliability Standards and supports the ongoing improvement of the efficiency and timeliness of the standards development process. The MRC is encouraged to provide feedback on the sufficiency of the various reform efforts underway, which include, but are not limited to: the restructuring of NERC leadership and staff for standards development; implementation of the recommendations from the Standards Process Input Group; initiation of the Reliability Issues Steering Committee; proposed revisions to the Standard Processes Manual; completion of a new Standards Committee strategic work plan and charter; and development of the 2013-2017 Reliability Standards Development Plan.

MRO supports the NERC BOT's leadership to develop clear, high-quality, technically excellent Reliability Standards. In particular, we believe that the strategic work of the Reliability Issues Steering Committee (RISC) can be significant in focusing on the right priorities such as making the standards setting process more effective and shaping the Reliability Assurance Initiative (RAI) as we scope the ERO's work around risk.

MRO also supports the 2013-2015 Standards Development Plan approved by the NERC BOT at its November 2012 meeting. While this plan does not address completion of the fill-in-the-blank standards as a separate matter, the fill-in-the-blank standards are addressed as part of the Standards Committee's ongoing work based on risk and priorities. MRO is particularly pleased that the standards development project 2010-05.1 Phase 1 of Protection Systems: Misoperations, and project 2010-03 Modeling Data addressing the MOD standards, will be completed and submitted to the NERC BOT for approval in 2013. Both projects contain fill-in-the blank standards or references to fill-in-the-blank standards and are important to the reliable operations of the bulk electric system (BES). Protection system misoperations have been identified as causal factors in most cascading events. Consistent and accurate models are critical to the current and future reliability of the BES.

MRO strongly encourages NERC to separately track the completion of the fill-in-the blank standards and continue to complete the fill-in-the-blank standards as soon as possible as these

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standards have been lingering, open matters since inception of the ERO and as directed in FERC Order 693. NERC should also consider whether there is an opportunity to complete all of the fill-in-the-blank standards and obtain approval as a "turnkey package."

Communications Protocols

Based on the balloting outcome of COM-003-1 and the ongoing importance of operator communications to the prevention of and response to system events, the Board is interested in the MRC's input on the anticipated path forward for development of and compliance with standards related to communications protocols. The following is a list of available resources: COM-001-2; COM-002-2a (with interpretation of definition of "directive"); COM-002-3 (not yet filed with FERC); COM-003-1 (the latest version); OC Guideline: System Operator Verbal Communication; FERC Order 693 (Paragraph 540 is the relevant directive for COM-003); 2003 Blackout Report (Recommendation 26 on page 59 of the pdf file is relevant for COM-003 and Order 693 Paragraph 540).

MRO continues to believe that the original COM standards supported the reliable operations of the BES. The recent work on the COM standards has largely centered on managing compliance risk, not improving the reliable operations of the BES. By focusing the standards on directives issued during an emergency, we ignore the importance of the need for everyday directives to be clear, concise and definitive to support the reliable operation of the BES and avoid an emergency. First, MRO believes that assessing compliance with COM standards should be done by staff that has extensive experience in real-time operations so they can exercise professional judgment to determine compliance. NERC oversight should require the proper skill sets to conduct the work and assess compliance. Second, MRO supports the NERC Operating Committee as the technical stakeholder group to revise its "Guideline" to focus on clear, concise, and definitive communications and include examples as a way to guide industry and NERC/Regional Entity staff on the proper application of the standard. The focus should be on clear, concise, and definitive communications between operators. Trained, experienced transmission system operators can determine an entity's capability of proper emergency communications simply by listening to high voltage switching orders which should be clear, concise, and definitive and include three-part communication. The practices and controls implemented for these switching orders provide reasonable assurance of meeting compliance and lay the foundation to drive operational excellence.

Reliability Assurance Initiative

In November 2012, the MRC and Board received an initial presentation on the Reliability Assurance Initiative (formerly titled Compliance Enforcement Initiative), that outlined an approach to develop an enhanced approach to the ERO's compliance monitoring and enforcement program. Activities to be undertaken as part of the Initiative include the engagement of industry in the development of conceptual white papers that help to describe the

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attributes and elements necessary to achieve a mature end state for this program. The Board is interested in hearing the MRC's input on the current initiative to include the various change state element papers already underway (Change State Elements), and the recently revised schedule for submitting a filing with FERC.

The Regional Entities will be the front-line practitioners who implement the RAI and therefore they need to continue to be closely involved in the development of the RAI. NERC should work alongside the Regional Entities in developing the tools, procedures, and training to roll-out the RAI in a consistent, disciplined manner. Ultimately, the success of the RAI will depend on the development of the actual program, tools, and training. Because it's not yet clear whether the changes in our approach and practices will require a filing at FERC, MRO supports the postponement of the March filing addressing the RAI. NERC and the Regional Entities should form an implementation pilot project team, obtain qualified staff from NERC and Regional Entities, and begin to work on the end product with an eye towards a pilot project in the third or fourth quarter of 2013. The project team can provide periodic briefings to the MRC during the development period through the initiation of the pilot project. The Trades/MRC Input Group provided written comments and questions on the RAI on December 11, 2012. MRO believes these comments and questions are useful in developing the actual program.

Three-Year Strategic Plan

The advance MRC materials will include the ERO's proposed three-year strategic plan, as well as a copy of the draft criteria that has been developed by NERC management for considering whether an activity should be funded under Federal Power Act Section 215. The MRC is encouraged to provide feedback on both the three-year strategic plan itself, including the goals and deliverables set forth in the plan, as well as the application of the draft Section 215 criteria to the goals and deliverables set forth in the three-year plan.

MRO supports the scope of ERO activities to be grounded in the plain language and explicit intent of the legislation, which is to prevent uncontrolled, cascading events. MRO suggests that the criteria NERC developed around the scope of activities have a close proximity to the plain language and explicit intent of the legislation to assure the ERO-enterprise and industry are always focused on the goal.

As we enter the planning period for 2014, MRO believes NERC should develop an enterprise risk management program across NERC and the Regional Entities to establish a common view of ERO-enterprise risks which should feed into the strategic plan to foster more consistency across NERC and the Regional Entities.

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Bulk Electric System Implementation

FERC Order 773 was issued on December 20, 2012, initiating the implementation of the revised definition of Bulk Electric System. As the standard drafting team continues Phase 2 of the project to provide additional clarity to the definition and resolve technical justification issues, the MRC is asked to share their feedback on the implementation plan, the compliance obligations for newly identified elements, the preparation of databases used to account for assets included in the Bulk Electric System, and anything else that may be of interest regarding this unique project.

As an ERO enterprise, our fundamental purpose is to support the reliable operations of the BES. By defining the facilities included and excluded as part of the BES, we clearly define the facilities subject to the Reliability Standards. And now that we have defined the BES, we must turn our attention to registration and certification.

Like the BES definition, the importance of technically sound registration and certification practices are critical to the reliable operations of the BES. For example, currently, single generators are being registered as Balancing Authorities in some parts of North America. While this may resolve contractual and administrative issues, a single generator has no load or generation to balance other than its own; and therefore, registration as a Balancing Authority is contrary to the technical purpose of the function. Failing to properly register functions will create unnecessary costs and more important, may well create gaps in the reliable operations of the BES. Similarly, the joint FERC and NERC report on the Arizona-Southern California Outages[1] clearly points to issues around the certification rules and process for Reliability Coordinators and Transmission Operators. MRO urges NERC to build much more *technical* oversight in both registration and certification processes, rather than acting as an administrative conduit.

In closing, the MRO Board of Directors and staff wish to thank John Anderson for his leadership on the BOT which has taken the organization from a voluntary association to its current role today as the Electric Reliability Organization (ERO). We look forward to working with Fred Gorbet as he assumes the leadership role on the NERC BOT.

The MRO Board of Directors appreciates the opportunity to provide this policy input to the NERC BOT.

[1] See http://www.nerc.com/fileUploads/File/News/AZOutage_Report_01MAY12.pdf.

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NPCC Board of Directors Policy Input

to the February 6, 2013 NERC Member Representatives Committee
and February 7, 2013 NERC Board of Trustees Meetings

1. **Standards Reform**
   - NPCC recommends that a targeted "Paragraph 81 - Phase 2" effort be initiated to apply the filed technical criteria for removing redundant or unnecessary requirements to those reliability standards that are not scheduled for overall review until the later years of the Reliability Standards Development Plan.
   - NPCC supports the pilot implementation of the Cost Effective Analysis Process being applied to Project 2010-13.2-Phase 2 of the Relay Loadability-Generation.
   - NPCC supports the filing of the TPL footnote b standard revision to clarify, with due recognition given to Canadian Provincial jurisdictions, under what circumstances and extent non-consequential loss of load may be used in planning studies.
   - NPCC recommends the expeditious filing of CIP Version 5, and the reconciliation of outstanding Version 3, 4 and 5 implementation issues.
2. **Communications Protocols**
   - NPCC recommends the filing of the COM - 002 -3 standard interpretation, and industry use of the Operating Committee's Guideline document addressing three part communication, and supports a NERC Technical Conference to facilitate industry consensus on effective communication protocols.
3. **Reliability Assurance Initiative**
   - NPCC supports a staged approach to the Reliability Assurance Initiative development and focusing the March 2013 compliance filing on the experience of the FFT implementation.
   - NPCC supports NERC's continuing collaboration with the Regional Entities and industry to change the compliance enforcement philosophy from a "zero defects" one to an evaluation of registered entities' procedures and controls.
4. **Three-Year Strategic Plan**
   - NPCC supports the earlier scheduling and release of the Three-Year Strategic Plan as a significant step forward to facilitate consistency within the ERO, where possible.
   - NPCC supports the overall goals and objectives identified in the Three-Year Strategic Plan as being consistent with the draft Section 215 criteria.
5. **Bulk Electric System Implementation**
   - NPCC supports the BES Standard Drafting Team efforts to revise the BES Guidance document to reflect industry comments received and directives from the December 20th FERC Order, and recommends it be adopted by the NERC BOT prior to the effective date of the revised BES definition (July 1st).
   - NPCC recommends that the NERC BES Exception IT tool be available to process BES Exception requests by the effective date of the revised BES definition.
   - NPCC recommends that potential revisions to the definition, as a result of the clarification work in Phase 2 of the BES SDT project, not establish an implementation scenario that strands investment.

Approved by the NPCC Board of Directors
at its January 30, 2013 Meeting

Sector 4 Policy Input to NERC Board of Trustees
January 31, 2013

Pursuant to the NERC Board of Trustee's (BOT) request for policy input from the NERC Member Representatives Committee for the upcoming February 6, 2013 meeting, Sector 4 respectfully submits the following for consideration by the NERC Board of Trustees.

Standards Reform

Sector 4 supports the NERC Board of Trustees leadership and direction to develop clear, high quality, technically excellent Reliability Standards. In particular, we believe that the strategic work of the Reliability Issues Steering Committee (RISC) will be significant not only in focusing the standards setting process, but in shaping the Reliability Assurance Initiative (RAI). Moving forward with integrating the prioritization work of the RISC, we should take care to ensure coordination and support from the various committees and groups as changes in the priorities of existing work will likely occur.

Sector 4 is wary of procedural reforms that deviate from normal ANSI procedures in order to expedite the development of a given standards project. In general, Sector 4 is concerned that the desire to bypass established procedures through the use of Rule 321 or the new waiver provision in the Standards Process Manual (SPM) could result in a situation that is inconsistent with the principles underlying the fundamental framework of an ANSI-accredited organization. Therefore, Sector 4 asks the Board to use extreme caution when considering invoking these approaches, given the significant departure it represents from normal procedures and ANSI principles.

Canadian members submit and Sector 4 supports that, in consideration of the numerous jurisdictional issues that standards development must address, it would be appropriate that a Canadian perspective is considered early in the standard development process. Sector 4 Canadian members are willing to meet with NERC staff to work together to develop suggestions on how this can be achieved. A good and typical example of jurisdictional differences is the amendment in the language of the TPL standards footnotes that NERC has to implement following the FERC Order No. 762, which remanded a proposed TPL standard to NERC for modification. Canadian entities were forced to initiate a formal appeal, pursuant to provisions of the Standards Process Manual, arguing that the Standard Drafting Team (SDT) failed to adequately address their concerns. At its January 16-17 meeting, the Standards Committee (SC) considered and approved the proposed alternative wording to address the jurisdictional difference. Appropriate coordination at an earlier stage would have avoided having to reach an appeal submission.

Communications Protocols

Sector 4 appreciates and supports NERC efforts to facilitate consensus through the announcement of a technical conference to discuss associated concerns and potential paths forward on COM-003-1. An "expedited method" to deal with this issue is not appropriate and

should be only used in the rare situation where an urgent reliability gap is identified subsequent to the regular standard development process.

Reliability Assurance Initiative

Sector 4 supports the incorporation of risk management concepts into the ERO's work, especially as it relates to compliance monitoring and enforcement, and generally supports the white paper "Incorporating Risk Concepts into the Implementation of Compliance and Enforcement". We plan to provide further comments once NERC's draft informational filing to the Commission becomes available. We also request the BOT to ensure that any contemplated changes are consistent with the Canadian regulatory/legal framework.

Three-Year Strategic Plan

Sector 4 and other entities throughout North America are under huge pressures to manage costs and minimize rate impacts in light of their customer's economic challenges. This industry is facing cost pressures due to political and economic conditions, transition to renewable energy resources, green technology, smart grid and the need to replace aging infrastructure. In addition, compliance obligations are increasing and the new BES definition will have huge impacts for some entities. While reliable operations are foundational to our industry and electric consumers, we must ensure that we are spending resources appropriately. NERC is taking positive steps to prioritize standards development, manage risk, and eliminate administrative requirements in standards. Additionally, Sector 4 suggests that NERC and the Regional Entities conduct a sensitivity analysis of a 10-15% budget reduction to ensure that costs are contained by means of specific productivity gains. Similar input was provided last year and we have not yet seen such an assessment by NERC or The Regional Entities.

We believe after such an analysis, prioritization of NERC activities should be undertaken along with identification of shared responsibilities for reliability solutions among NERC, industry (such as Sector 4, NATF, EEI but not limited to), and other partnerships that can be achieved. This approach will ensure NERC is focusing on its core mission while allowing other entities to engage in broader issues affecting the electric utility industry.

Bulk Electric System Implementation

Sector 4 believes that the drafting team did an excellent job in proposing a new bright-line definition for elements 100 kV and above. Comments from several commissioners on the FERC approval of the definition are reflective of this. For many entities the 24 months implementation requirement will be challenging in several areas and NERC should develop a simple extension process. Otherwise, there could be unintended reliability risk to the BES since resources could be diverted from other key areas.

Sector 4 is also concerned with several directives as part of the FERC Order approving the definition. For example – FERC first establishing a 100 kV bright-line and then directing NERC

to remove this or local distribution demarcation from the "local network". As articulated by the drafting team, elements below 100 kV and/or Distribution elements necessary for the operation of interconnected BES can be designated BES through the exception process. If NERC addresses these FERC jurisdictional types of directives in international standards, then it must a) identify to FERC the delays in standard development due to FERC's directives and b) educate the SDT regarding FERC jurisdictional boundaries and to include provisions for non-jurisdictional entities (such as Canada and Mexico) for requirements on elements that are not necessary for the operation of interconnections.

Sector 4 appreciates the opportunity to comment and thanks the Board for their consideration. We look forward to discussing these matters further at the meeting San Diego.

SERC Board of Directors Policy Input to NERC
February 2013

The SERC Board of Directors appreciates the opportunity to provide policy input to NERC for the February 2013 Board of Trustees (BoT) and Member Representatives Committee meetings.

Trustees

First and foremost, the SERC Board acknowledges the service of Chairman Anderson, Trustee Bailey, and Trustee Berry, who are concluding their service on the NERC BoT. While all three trustees have faithfully served NERC during their respective tenures, Chairman Anderson, using unparalleled commitment and leadership, has artfully led the organization during a challenging transitional period. Chairman Anderson has been instrumental in keeping NERC focused on its mission and on implementing a successful electric reliability organization model. The SERC Board expresses its deep appreciation for Chairman Anderson, Trustee Berry, and Trustee Bailey, and wishes them the best in future endeavors.

Standards Reform

- While the SERC Board believes that primary responsibility for development of continental reliability standards rests with NERC rather than the regional entities, the SERC Board notes that many of SERC's delegated functions, particularly in the compliance and enforcement areas, require a set of high quality standards to be successfully carried out.
- Given the NERC community's passionate and numerous discussions on the number of ineffective requirements in the ERO reliability standards, the SERC Board is disappointed with the limited number of "Paragraph 81" requirements that are being presented to the NERC BoT for consideration to retire (BoT Agenda Item 9.a.ii). The NERC BoT is encouraged to review this Phase I experience to understand how implementation of the work plan and regular processes resulted in this meager result.
- Because the ERO reliability standards are a primary input for SERC's compliance and enforcement activities and because SERC desires for its staff and registered entity resources to work on items that impact reliability, NERC is encouraged to move expeditiously to Phase II of the Paragraph 81 activity as a major contributing activity to improving the quality of the ERO standards.
- Lastly, the SERC Board has a strong interest in furthering its understanding of the ERO's pursuit of performance and/or results based standards.

Communications Protocols

- SERC supports an approach that provides an appropriate balance between the need to address the Order 693 directive, the recommendations from the 2003 Blackout, and the input that has been provided by the industry during COM-003 development.
- Great care should be exercised to ensure any and all mandatory requirements are clearly measureable and enforceable.

Reliability Assurance Initiative (RAI)

- Successful design and implementation of RAI is critically important for achieving better balance between a reliability focus and a compliance/enforcement focus.
- SERC endorses and appreciates NERC's decision to take additional time to conceptualize the RAI.
- SERC stakeholders are anxious to see all the concept papers to understand the ideas being pursued and to support timely implementation.
- While stakeholders want to understand the broader objectives of the Reliability Assurance Initiative, NERC is encouraged to capture incremental improvements along the way. In familiar words, SERC advises, "Don't let the Perfect be the enemy of the Good."
- SERC also recognizes that all members of the NERC community will need to commit to working collaboratively to fully implement RAI in absence of unnecessary distraction.

MEMORANDUM

TO: Holly Mann, Secretary
NERC Member Representatives Committee

FROM: Tim J. Arlt
John DiStasio
Bill Gallagher
John Twitty

DATE: January 31, 2013

SUBJECT: Response to Request for Policy Input

The MRC's State and Municipal and Transmission Dependent Utility Sectors ("SM-TDUs") appreciate the opportunity to respond to the January 10, 2013 letter from NERC Board Chair John Q. Anderson to Ms. Carol Chinn, Chair-Elect of the NERC Member Representatives Committee ("MRC"), requesting policy input on topics to be discussed by the NERC MRC and the NERC Board of Trustees at the upcoming February 2013 meetings.

This response addresses each of the five topics raised in Mr. Anderson's letter: Standards Reform, Communications Protocols, the Reliability Assurance Initiative, NERC's Three-Year Strategic Plan and implementation of the Bulk Electric System Definition.

At the outset, each of us would like to express our heartfelt thanks to John Q. Anderson for his many years of service and leadership as a Trustee for the North American Electric Reliability Corporation, and for the last four years, as Chair of the Board of Trustees. His leadership, wise counsel and open-mindedness to the perspectives of all of NERC's many diverse stakeholders and governmental authorities have proved instrumental to every aspect of NERC's transition from a voluntary council of industry participants and regional organizations to an independent electric reliability organization charged by Congress and Canadian provincial authorities with ensuring the reliable operation and planning of the bulk power system in North America. Among other things, his tenure as Chair has seen a vastly improved relationship among NERC, FERC and stakeholders; a shifting focus from mere compliance to reliability and performance-based standards; and an overall more businesslike approach to the affairs of NERC. He has led NERC with calm, patience, superb judgment and humor, through innumerable trials large and small. He has our deep thanks.

I. Standards Reform

The SM-TDUs fully endorsed the standards policy resolution that was approved by the Board of Trustees at its November 2012 meeting. Many reform efforts are now underway or nearing completion, including the restructuring of NERC leadership and staff for standards development, implementation of the recommendations from the Standards Process Input Group, approval and initiation of the Reliability Issues Steering Committee, approval of revisions to the Standard Processes Manual, completion of a new Standards Committee strategic work plan and charter, and

development of the 2013-2017 Reliability Standards Development Plan. All of these efforts should all be allowed to move to implementation without further changes in policy direction, scope or governance beyond those presented for Board approval this February.

Our reasons for this stance are practical: the Board, NERC management and stakeholders devoted substantial resources to launching each of the initiatives outlined in your letter. Now it is time to allow the NERC standards program, the Standards Committee and the Reliability Issues Steering Committee to develop the new processes that are needed to actually carry out this change in direction. For example, ensuring that all new or revised standards are technically sound, clear and results-based is not a simple task, in light of the many standards projects that are already under development. The SC's Strategic Work Plan and 2013-2017 Reliability Standards Development Plan each adopt challenging goals for 2013 and 2014. SM-TDUs emphasize that the Paragraph 81 initiative to retire redundant or unnecessary reliability standards must not be allowed to falter or lose momentum.

SM-TDUs also support adoption of the RISC's recommendations at BOT Agenda Item 12, page 24:

> The RISC recommends that the Board adopt [the RISC's proposed] strategic prioritization and endorse the RISC's continued work on a gap analysis on the high-priority and then the medium-priority issues.
>
> In addition, the RISC recommends that the Board direct NERC to incorporate these priority rankings into the development of ERO business plans, and direct NERC Committees to incorporate these priority rankings into the development of their plans – including empowering committees to stop or defer lower priority work.
>
> We further suggest that the RISC be directed to work with NERC staff and Standing Committee leadership to create a results-driven Reliability Strategy development process that integrates with budget development and overall ERO planning (e.g., Standing Committee planning, department and employee goal setting).

We recommend that NERC incorporate the RISC's strategic prioritization effort into *all* of NERC's programs, not merely the standards program. However, this process should take place during planning for the 2014-2016 Business Plan and Budget process rather than as mid-course corrections to the current-year plan.

II. Communication Protocols

SM-TDUs continue to support the approach to "three-part" communication as required in approved standard COM-002 and proposed in draft standard COM-003. COM-002 requires the use of three-part communications during emergencies and in response to conditions that may lead to an Adverse Reliability Impact. In contrast, draft COM-003 adopts a programmatic approach to compliance that emphasizes registered entity self-identification and correction of performance deficiencies. This approach properly focuses utility operators on learning to use three-part communications for operating instructions during normal operations, thereby ensuring that clear and effective three-part communications are used during pre-emergency and emergency conditions.

However, most verbal communications between System Operators entail the exchange of routine operating condition information, not "operating instructions" to change the configuration of the BES. These routine information exchanges do not need to take place through three-part communication protocols to ensure that operators carry out their responsibilities. Put another way, it makes sense to require operators to use three-part communications during emergencies. It makes sense to train operators to use three-part communications for operating instructions issued during normal operations. However, it is not appropriate for a NERC standard to require operators to use three-part communications for routine communications under normal operating conditions or for the standard to require registered entities to document all of their routine operating communications. Doing so will create additional work without any benefit to the reliability of the Bulk Power System.

Industry stakeholders remain concerned with how proposed COM-003 will be enforced. SM-TDUs suggest that all CEOs work with their companies, sectors, NERC management and Regional Entities to obtain agreement on an acceptable set of communications standards and associated compliance elements, including Reliability Standard Audit Worksheets. SM-TDUs seek greater clarity on how NERC and Regional Entities will assess the quality and implementation of an entity's internal controls.

III. Reliability Assurance Initiative

SM-TDU's fully support the January 30, 2013 Joint Trade Association Policy Input on the Reliability Assurance Initiative ("RAI").[1] We will not repeat or summarize the Joint Trade Association Policy Input here, but do reiterate two points we have made on many occasions before: on behalf of our state-municipal and transmission dependent utility sector members, we urge NERC and the Board of Trustees to afford the RAI its highest priority. We also urge NERC to push ahead on the transition of Find, Fix and Track to its next stage: Find, Fix and Record. No other set of NERC initiatives have a greater potential to free up NERC, regional and industry resources for better uses than a more effective, risk-based compliance program.

IV. Three-Year Strategic Plan

SM-TDUs generally support the NERC Three-Year Strategic Plan for 2013-2015 and pledge to work with NERC to establish achievable, measurable ERO and RE goals and performance metrics for the plan. This goal and performance metric development process will be critically important to the success of the 2014 NERC Business Plan and Budget process that is now being initiated. As an initial matter, the Strategic Plan should be mapped against NERC's current program activities as well as the criteria for certification as the ERO. Also, the Strategic Plan does not set clear objectives for communication with stakeholders and reliance upon the subject matter expertise of industry through standard drafting teams and NERC's extensive committee structure. As a

[1] Joint Trade Association Response to January 10, 2013 Request for Policy Input from NERC Board Chairman John Q. Anderson on the Reliability Assurance Initiative (RAI). The Joint Trade Associations include the American Public Power Association, Edison Electric Institute, Electric Power Supply Association, Electricity Consumers Resource Council, the Large Public Power Council, National Rural Electric Cooperative Association and Transmission Access Policy Study Group.

related matter, SM-TDUs support the revised Section 215 Budget Criteria that were presented to the Board for approval during its January 30, 2013 meeting by conference call.

V. Bulk Electric System Definition

SM-TDUs continue to support FERC approval of the Phase One BES Definition as filed by NERC in January 2012, while recognizing that Commission Order No. 773 directed several changes in how NERC interprets the filed definition. The American Public Power Association, the Transmission Access Policy Study Group and other groups each sought rehearing of the Commission's final rule on a number of grounds. SM-TDUs are both surprised and disappointed that NERC did not take issue with the Commission's determination that it could lawfully direct NERC to interpret the BES Definition in ways that are clearly inconsistent with the plain meaning of the Definition, without remanding the Definition to NERC. Nonetheless, SM-TDUs recognize that unless a stay of effectiveness is issued by the Commission, many of our members may be forced to submit detailed exception requests to NERC, seeking clarity as to whether their distribution facilities are now deemed to be BES facilities. Other members may be forced to seek determinations directly from FERC that their facilities are "used in local distribution."

SM-TDUs also support efforts by the BES Drafting Team to complete and post a revised Guidance Document to assist industry stakeholders in the implementation of the BES Definition, as well as completion of Phase 2 of the BES Definition project.

Thank you for the opportunity to provide this input.

MEMORANDUM

TO: Holly Mann, Secretary
NERC Member Representatives Committee

FROM: Allen Mosher, Vice President, Policy Analysis & Reliability Standards, American Public Power Association
Bill Gaines, Director of Utilities and CEO, Tacoma Utilities, on behalf of the Large Public Power Council
John Twitty, Executive Director, Transmission Access Policy Study Group

DATE: January 31, 2013

SUBJECT: Response to Request for Policy Input

The American Public Power Association, the Large Public Power Council, and the Transmission Access Policy Study Group have reviewed and concur in the response submitted today by the State/Municipal and Transmission Dependent Utility Sectors to NERC Board Chair John Q. Anderson's January 10, 2013 letter requesting policy input in advance of the February 2013 NERC Board of Trustees meeting.

In addition, the American Public Power Association, the Large Public Power Council, and the Transmission Access Policy Study Group are sponsors of the Joint Trade Association Policy Input on the Reliability Assurance Initiative, dated January 30, 2013.



Joint Trade Association Response to January 10, 2013
Request for Policy Input from NERC Board Chairman John Q. Anderson
on the Reliability Assurance Initiative (RAI)

January 30, 2013

The Trade Associations[1] support the conclusion drawn in NERC Staff's conceptual White Paper that

> [i]t is not practical, effective or sustainable for the ERO Enterprise and Registered Entities to monitor and control all compliance to the same degree. Further, it is not practical, effective, nor sustainable for the ERO Enterprise and Registered Entities to treat all findings and discrepancies, as violations triggering the same degree of enforcement and evidentiary documentation. Where a violation does not pose a serious or higher risk to the reliability of the bulk power system, and the Registered Entity has a compliance program and internal controls that detect, assess, mitigates and self-reports the violation, the Regional Entity may decline to pursue an enforcement action. [2]

The Trade Associations further support the aims articulated in NERC's "Change State Element Paper No. 1 (Restyle the Compliance Monitoring Approach)" that:

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[1] This response is supported jointly by American Public Power Association, Edison Electric Institute, Electric Power Supply Association, ELCON, the Large Public Power Council, National Rural Electric Cooperative Association and Transmission Access Policy Study Group.

[2] http://www.nerc.com/files/Reliability_Assurance_Initiative_Risk_Concepts_White_Paper.pdf, at p. 2.

- "…the compliance monitoring approach will be restyled to be more explicitly shaped around the risk to reliability;"[3] and

- "Audits should be scoped to address the potential risk the entity poses to the BPS and the potential risk to comply with established reliability standards."[4]

While the Trade Associations appreciate the effort NERC staff has undertaken to elicit our input on the RAI, there is serious concern with steps taken, to date, to develop and implement the program. These concerns center on: (1) the potential for NERC's focus on the development of the RAI program to interfere with maturation of the Find-Fix-Track ("FFT") program; (2) the lack of clear direction governing registered entity and regional entity responsibilities; (3) the need for a realistic plan for developing and implementing the program, including the management of any necessary filings with FERC; and (4) the need for each regional entity to demonstrate their commitment to implement both programs in a timely and consistent manner. These issues are addressed below.

(1) Relationship to FFT

With its initial filing in support of the FFT program, NERC indicated that in a second implementation phase, it would work with its compliance and enforcement staff to authorize compliance field staff, auditors and investigators to make determinations regarding violations eligible for FFT treatment. In conditionally accepting NERC's initial September 2011 FFT proposal, FERC commented favorably on this second phase, paraphrasing NERC's proposed approach as follows:

> NERC explains that, in Phase II, both compliance staff and enforcement staff would determine the ultimate disposition of possible violations. NERC proposes that compliance field staff, auditors and investigators make such determinations in the course of compliance audits, spot checks and compliance investigations, and that there will be constant collaboration with NERC and Regional Entity enforcement staff.[5]

The Commission permitted NERC to move ahead with this phase of the program, subject to the submission of further information regarding necessary training programs and procedures assuring coordination between compliance and enforcement personnel, and protocols ensuring consistent outcomes.[6]

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[3] http://www.nerc.com/files/RAI%20Change%20State%20Element%20No%201%20-%20Restyle%20the%20Compliance%20Monitoring.pdf, at p. 2.

[4] *Id.*, at p. 9.

[5] 138 FERC ¶ 61,193 at P 24 (2012) (the "March 15 Order").

[6] *Id.* at PP 79-80.

The Trade Associations strongly encourage NERC, with the commitment and support of the regional entities, to move ahead with this second phase of the FFT program at this time, independent of its schedule for developing and implementing the RAI program. While the Trade Associations recognize some overlapping effort between the RAI and FFT initiatives with respect to training for compliance personnel, the Associations urge NERC to seize the opportunity that the March 15 Order presents now. Though the Trade Associations are hopeful that NERC will make progress in developing and ultimately implementing the RAI, the effort is undeniably complicated and may require some additional regulatory approval or acquiescence. With the regulatory hurdles for the second phase of the FFT program having been cleared, it would be a misjudgment to forego the immediate opportunity for further progress. Furthermore, additional success with respect to the second phase of the FFT effort may very well smooth the way for the incremental RAI effort.

(2) The Need for Clarity Regarding Registered Entity and Regional Entity Responsibilities Under the RAI

The Trade Associations are concerned that insufficient attention has been paid, to date, to the development of a clear statement of the impact the program will have on registered entities (including the identification of reliability benefits and cost savings), and the expectations of, and responsibilities imposed upon, registered entities. Our understanding is that the RAI will be designed to scale compliance oversight to the risk profile presented by a registered entity, and that such risk will be ascertained as a function of the strength of each entity's compliance program (including internal controls) and physical circumstances. Central questions regarding how registered entities will address these new criteria have yet to be answered, including: (1) how internal controls are defined and evaluated; (2) whether internal controls are relevant to all, or only a subset of, the reliability standards; (3) whether and how the criteria for evaluation of internal controls will vary based on the size of the registered entity; (4) how registered entities will document their internal controls and compliance programs; (5) how registered entities will document and represent their views of the physical risk profiles they present; (6) what role self-reports will have in the new regime; (7) how the RAI will manage the evaluation of entities whose business units span multiple regions; and (8) how NERC will oversee regional programs.

As well, the RAI documentation, to date, contains little information regarding the standards or protocols by which regional enforcement entities will evaluate registered entities under the RAI, and how those evaluations will factor into determinations regarding compliance oversight. Criteria for such evaluations, and their effect on compliance oversight should be clearly understood and the evaluations predictable, in order to ensure a degree of consistency between entities and among regions, and assure registered entities that the program is being administered fairly.

The Trade Associations have provided NERC Staff with outlines for two additional papers, addressed to the broad questions outlined above, to supplement development of the RAI. We ask for a commitment by NERC to work with the Trade Associations and other stakeholders in responding to this input as development of the RAI progresses.

(3) NERC Must Work With a Realistic Plan for Developing and Implementing the RAI.

By letter dated December 6, 2012, the Trade Associations urged NERC to step back from what appeared to be a commitment to file with FERC by March 15, 2013 a proposal to implement the RAI. The Trade Associations expressed general support for the RAI, and appreciation for NERC's interest in considering industry input,. However, the Trade Associations were also concerned that a self-imposed deadline for a filing by March 15 would short-circuit NERC's ability to receive and process all necessary input, and potentially undermine critical stakeholder support.

NERC Staff's background material for MRC Agenda Item 6(b) indicates that NERC has tabled the proposed March 15 deadline, responding to the Trade Association input. The Trade Associations appreciate NERC Staff's responsiveness on this point, and reiterate here the importance of not rushing the RAI toward a FERC filing before all needed input can be considered. The Trade Associations are fully prepared to work with NERC and the regions to provide constructive, timely input in order to assist NERC in developing a coherent package around which broad consensus can be reached. Toward that end, the Trade Associations urge NERC Staff to develop and adhere to a realistic plan for bringing the RAI to fruition, incorporating a workable schedule for eliciting thoughtful industry input, and outreach to FERC. An effective management plan for the RAI would describe the steps to be taken, timelines, and the sequence of activities. The plan would foster management discipline and accountability, provide transparency, and allow all parties to schedule their work efforts against multiple work tasks competing for limited time. As well, careful consideration must be given to determining which elements of the RAI, if any, call for FERC approval.

The Trade Associations also encourage NERC to consider the merit of moving ahead with the RAI in phases, perhaps through the consideration and analysis of pilot programs undertaken voluntarily, while permanent protocols are ironed out. The RAI is an ambitious program, calling for substantial coordination with the regional entities, reworking of existing compliance programs and training at all levels. Considering the program in phases may enable NERC, the regions and the industry to more carefully consider and accommodate this change in the compliance paradigm, if implemented pursuant to a concrete and realistic plan.

Above all, the Trade Associations urge NERC, following deliberate consideration, to place a priority on letting the compliance and enforcement program settle into a durable and repeatable set of processes and activities. While NERC's history of experimentation in the compliance and enforcement space reflects a healthy interest in innovation, it is important to recognize that there is a limit to the industry's and FERC's ability to process endless changes in these programs. With each innovation, NERC calls for the industry to reorganize its compliance efforts, with significant costs and inevitable inefficiencies. The costs include not only direct time and expenditures on personnel, but adverse reliability risks associated with continuous changes in process. NERC is nearing the point where it must get these programs right, and give the industry time to settle into managing a mature program.

(4) The Need for Regional Entity Commitment to Implementation of the FFT and RAI Programs.

Since the establishment of the ERO, stakeholders have made consistent implementation of compliance and enforcement programs by all of the regional entities a priority. As the FFT program has developed, there has been concern that not all the regional entities are equally committed to its full implementation. As we move forward with the next phases of FFT and the development and implementation of the RAI, it is essential that all regional entities demonstrate their commitment to the goals and consistent implementation of these programs.

Policy Input to NERC Board of Trustees
January 30, 2013

In response to the invitation of the Chair of the NERC Board of Trustees dated January 10, 2013, the WECC and Texas RE representatives to the Member Representatives Committee (MRC) offer the following comments for consideration.

Three-Year Strategic Plan: The policy input requested in the invitation indicated that:

> "The advance MRC materials will include the ERO's proposed three-year strategic plan, as well as a copy of the draft criteria that has been developed by NERC management for considering whether an activity should be funded under Federal Power Act Section 215. The MRC is encouraged to provide feedback on both the three-year strategic plan itself, including the goals and deliverables set forth in the plan, as well as the application of the draft Section 215 criteria to the goals and deliverables set forth in the three-year plan."

Comments:
WECC and Texas RE appreciate NERC's continuing efforts to improve strategic planning. We commend the significant progress made by the ERO Enterprise under NERC's leadership in producing a timely and meaningful product that informs our own regional Business Plans and Budgets. It is still a work in progress and ideally would have fewer and more focused goals, objectives, projects and measures. The NERC Board of Trustees should continue to work with NERC management to produce a realistic number of priorities and projects. The current document contains many worthy goals to aspire to that can be added in the future as the ERO Enterprise tackles a feasible number of highest-priority issues first.

Bulk Electric System Implementation: Input also was requested as follows:

> "FERC Order 773 was issued on December 20, 2012, initiating the implementation of the revised definition of Bulk Electric System. As the standard drafting team continues Phase 2 of the project to provide additional clarity to the definition and resolve technical justification issues, the MRC is asked to share their feedback on the implementation plan, the compliance obligations for newly identified elements,

the preparation of databases used to account for assets included in the Bulk Electric System, and anything else that may be of interest regarding this unique project. ‘

Comments:
Despite a great deal of time, effort and resources on the part of NERC and the Regions, at this time it appears likely that there will not be an automated tool ready for use by the Regions to manage the processes attendant to implementation. Since the issuance of the NOPR in June of last year, it has been clear that FERC was generally supportive of the filing and intended to move fairly quickly. As a result, a July 1, 2013 effective date for the new definition is not a surprise. While discussions are underway about ways to implement a scaled-down version by July 1, the concern that the automated tool will not be ready before implementation is indicative of problems with NERC’s Project Management Office’s (PMO) processes. The PMO has been working on developing a “cooperative model” for ERO Enterprise-wide projects, such as the Bulk Electric System Exception Process tool, which would define the roles and responsibilities of NERC and the Regions, as well as clarifying the process. The NERC Board should strongly encourage management to prioritize the development of the cooperative model, and associated governance and processes, so that future projects will be completed both timely and effectively.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda Item 9
Board of Trustees Meeting
February 7, 2013

Reliability Standards

Mark Lauby, Vice President and Director of Standards
Board of Trustees Meeting
February 7, 2013

RELIABILITY | ACCOUNTABILITY






Proposed Continent-Wide Standards

- BAL-003 – Frequency Response – **Adopt**
- Paragraph 81, Phase 1 – **Adopt 20 standards**
- TPL Table 1, Footnote b – **Adopt**
- Generator Verification – **Adopt 4 standards**

BAL-003-1 Frequency Response and Frequency Bias Setting

- Reliability Implications
  - For the first time, industry has agreed on a minimum obligation for operational frequency response
- Action
  - Adopt BAL-003-1 Frequency Response and Frequency Bias Setting and implementation plan

Paragraph 81, Phase 1

- Reliability Implications
  - Stepping stone to clear, concise, results-based standards
- Action
  - Adopt 20 reliability standards and implementation plans

TPL Table 1, Footnote b

- Reliability Implications
  - Establishes an industry agreed upon method to consider non-consequential load shed for planning purposes
- Action
  - Adopt TPL-001-2b and TPL-001-3 (TPL Table 1, Footnote b) and implementation plans

Generator Verification

- Reliability Implications
  - For the first time, unnecessary generator tripping is addressed by coordinating protection system settings
- Action: Adopt four standards and implementation plans
  - MOD-025-2 Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
  - MOD-026-1 Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
  - MOD-027-1 Verification of Models and Data for Turbine/Governor and Load Control of Active Power/Frequency Control Functions
  - PRC-019-1 Coordination of Generation Unit or Plant Capabilities, Voltage Controls, and Protection

Proposed Interpretations and Regional Standards

- Interpretation of TPL-003-0a and TPL-004-0 requested by the Planning Committee's System Protection and Control Subcommittee (SPCS)
- Interpretation of CIP-002-3 requested by Oklahoma Gas and Electric (OGE)
- IRO-006-WECC-2 – Qualified Transfer Path Unscheduled Flow Relief

Interpretation of TPL-003-0a and TPL-004-0

- Result
  - Both a stuck breaker or protection system failure must be evaluated to determine the most severe system impacts due to delayed clearing
- Action
  - Adopt Interpretation requested by the Planning Committee's SPCS on TPL-003-0a and TPL-004-0

Interpretation of CIP-002-3

- Result
  - Interpretation clarifies that critical asset criteria is facts and circumstance-driven, not exclusively technology-dependent
- Action
  - Adopt Interpretation requested by OGE of CIP-002-3

IRO-006-WECC-2 – Qualified Transfer Path Unscheduled Flow Relief

- Background
  - Updates WECC's Unscheduled Flow Reduction Guideline
- Action
  - Adopt IRO-006-WECC-2 – Qualified Transfer Path Unscheduled Flow Relief

Reports for Action or Information

- Midwest Reliability Organization's (MRO's) Regional Standards Development Procedure
- Analysis of revised TOP standards
- COM-003-1 – Operating Personnel Communications Protocols

Midwest Reliability Organization Regional Standards Development Procedure

- Background
  - Aligns with NERC's Standard Processes Manual
- Action
  - Adopt MRO's Regional Standards Development Procedure Version 5.0

Analysis of Revised TOP Standards

- Background
  - May 2012 – Board of Trustees adopted three revised TOP standards:
    - TOP-001-2 Transmission Operations
    - TOP-002-3 Operations Planning
    - TOP-003-2 Operational Reliability Data
  - Requested staff review standards to ensure no new reliability gaps
- Result
  - No new gaps in reliability created by new standards
  - Monitoring and analysis considerations addressed in a 2013 project



Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda Item 10
Board of Trustees Meeting
February 7, 2013

Standards Process Reform

Mark Lauby, Vice President and Director of Standards
Holly Hawkins, Assistant General Counsel
Laura Hussey, Director of Standards Development
Board of Trustees Meeting
February 7, 2013

RELIABILITY | ACCOUNTABILITY






Components of Reform

- Previous work
  - 2013-2015 Reliability Standards Development Plan
  - Standards Department reorganization
- Presented today
  - Strategic Plan, Work Plan and Charter
  - Revisions to NERC Standard Processes Manual (SPM)
  - Phase 1 of Paragraph 81
- Ongoing 2013
  - Address outstanding directives, five-year reviews
  - Application of Paragraph 81 and results-based principles
  - Roadmap development to transform standards

Status of Initial SPIG Recommendations

- Standards Process Input Group (SPIG) Recommendations
  - 1 – American National Standards Institute accreditation
  - 2 – Form Reliability Issues Steering Committee (RISC)
  - 3 – Government outreach
  - 4 – Standards product
  - 5 – Standards process and resources
- Status
  - All recommendations are being implemented

Standards Committee Strategic Plan and Work Plan

- Background
  - Strategic Plan – establishes vision, mission, guiding principles
  - Work Plan – tactical implementation of strategic plan
  - Both plans plus Standards Committee (SC) charter implement the November 2012 Board of Trustees' Resolution
- Action
  - Approve strategic plan and work plan

Standards Committee Charter

- Summary of changes
  - Accountable to the Board of Trustees
  - Long-term vision consistent with ERO's strategic and business plans
  - Responsible for developing comprehensive, results-based standards
  - Agile, properly skilled, and focused standard drafting teams
  - Change voting from 2/3 to simple majority, except SPM and Charter
- Action
  - Approve revisions to SC Charter

Standard Processes Manual Revisions

- Summary
  - Implement SPIG's recommendations on:
    - Drafting team composition
    - Collaboration with Compliance on Reliability Standard Audit Worksheets
    - Streamlined commenting and balloting
    - Treatment of negative votes without comments
  - Incorporate limited waiver provision
  - Periodic review modified from five years to ten years
  - Revisions comport with ANSI Essential Requirements
- Action
  - Approve revisions to NERC SPM

Standards Committee Officers

- Background
  - Replace current chair and vice chair through December 2013
  - Results:
    - Chair elect: Brian Murphy, NextEra
    - Vice Chair elect: Scott Miller, MEAG Power
- Action
  - Approve SC chair and vice chair
  - Appoint Brian Murphy to serve on RISC



Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda Item 12
Board of Trustees Meeting
February 7, 2013

RISC Recommendation on ERO Priorities

Chris Schwab, RISC Chair
VP – Chief Compliance and Risk Officer, Dominion
Board of Trustees Meeting
February 7, 2013

RELIABILITY | ACCOUNTABILITY

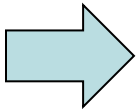





Prioritization Process

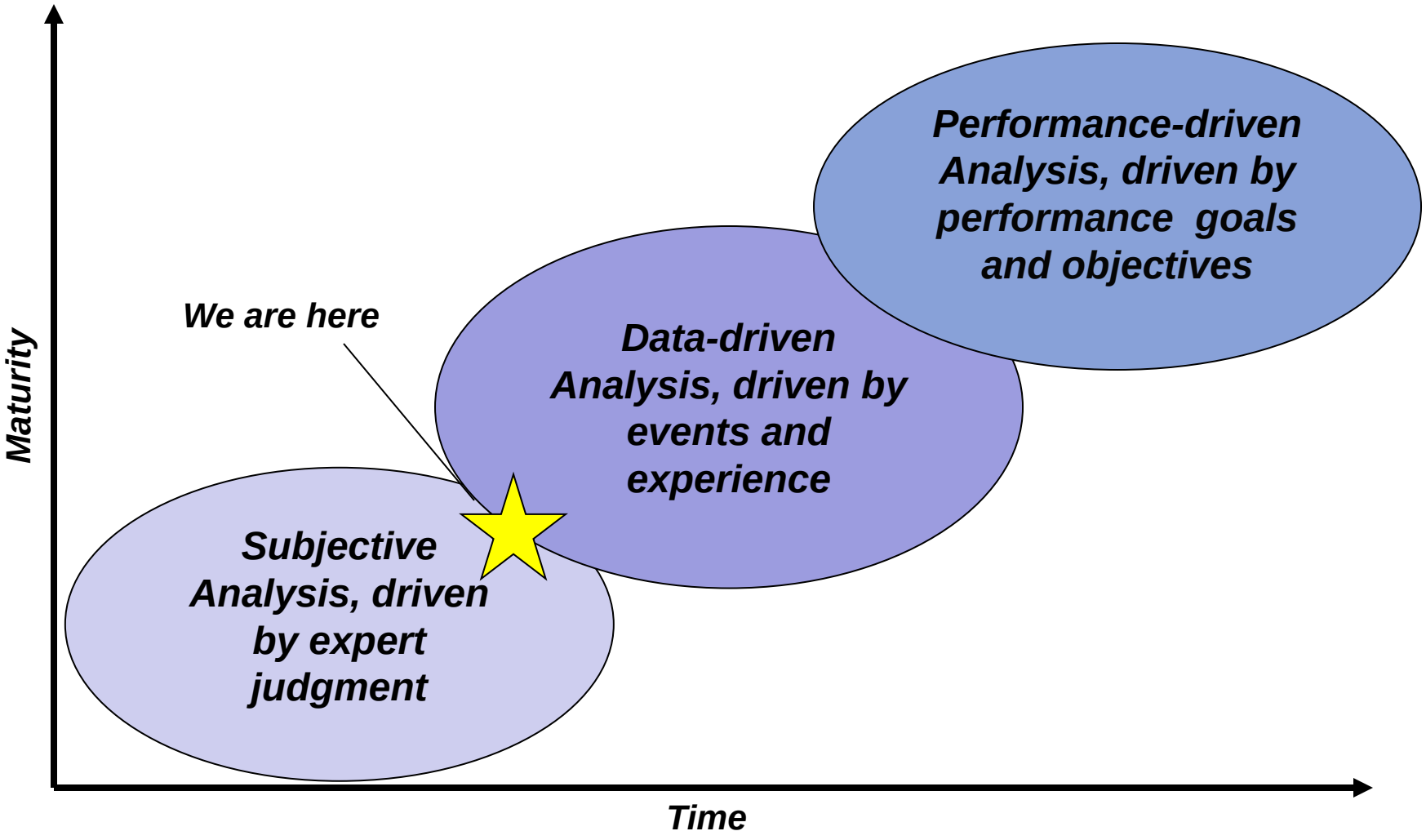
Reliability Issues Steering Committee

- Provides framework for focusing resources on critical BPS reliability issues
- Triages issues and provides front-end, high-level leadership
- Helps establish common understanding of issue scope, priority, and goals
- Recommends solutions, including other than the development of standards



Initial Strategic Prioritization	• NERC Staff identified all ERO activities related to reliability and grouped them into risk areas • Asked RISC members to evaluate: o Impact and probability? o Existing controls? o Gaps? o How to address gaps? o Post-control priority? • Results correlated with budget exercise

Process Maturation



Prioritization Results

HIGH PRIORITY
Issues that affect entire ERO

- **Highest resource allocation**
- **Perform complete gap analysis for every category**
- **Gaps defined and problem statement written with measurable metrics for success**
- **Consider addressing gaps with resources presently utilized for lower priority issues**
- **If that is not possible, justify incremental resources**

MEDIUM PRIORITY
Issues that need further definition or may be regional in nature

- **Further analyze to assess if there is a specific issue that needs to be addressed**
- **If there are specific issues that need to be addressed, fund from re-allocation of resources from lower priority issues**
- **Should not apply incremental resources to this level**

LOW PRIORITY

- **Monitor and incorporate in periodic review of priorities**
- **Use as base to re-allocate resources**

High Priority Issues

- Cyber Attack
- Workforce Capability and Human Error
- Protection Systems
- Monitoring and Situational Awareness

PERFORM COMPLETE GAP ANALYSIS

- *Are the existing efforts sufficient? Are all of the existing efforts needed?*
- *Ensure that any new effort is in NERC's scope or appropriately directed to the right organization.*
- *What gap was identified that the effort is meant to solve?*
- *What data is available to scope new activity?*
- *How will we measure performance? What metrics will define and track success?*
- *How will we fund the incremental project without increasing the budget? What resources currently directed to lower priority resources will be redirected toward these higher-priority issues?*
- *If a budget increase is necessary, justify the increase.*

Medium Priority Issues

- Operational Modeling and Model Inputs
- Equipment Maintenance and Management
- Coordinated Attack on Multiple Facilities
- Generator Availability
- Increased Dependence on Natural Gas Generation

FURTHER ANALYZE TO DETERMINE SPECIFIC ISSUE

- *What specific areas should we be focusing on?*
- *Ensure that any new effort is in NERC's scope or appropriately directed to the right organization.*
- *What is the scope of this issue?*
- *Are the existing efforts sufficient? Are all of the existing efforts needed?*
- *What gap was identified that the effort is meant to solve?*
- *What data is available to scope new activity?*
- *How will we measure performance?*
- *How will we fund the incremental project without increasing the budget? What resources currently directed to lower priority resources will be redirected toward these higher-priority issues?*
- *Activities in this area should not necessitate an increase in budget*

Low Priority Issues

- Generation Resource Adequacy
- Transmission Right of Way
- Geomagnetic Disturbance (GMD)
- Long Term Planning and Modeling
- Climate Change, Environmental Regulations, Changing Resource Mix due to Environmental or Other Market Conditions, Integration of Variable Gen
- Integration of New Technologies
- Extreme Weather/Acts of Nature
- Demand Response
- Localized Physical Attack
- Smart Grid
- Electro-Magnetic Pulse
- Post-Recession Demand Growth
- Pandemic

MONITOR

and incorporate in periodic review of priorities. Use as base to re-allocate resources to higher priority issues as needed

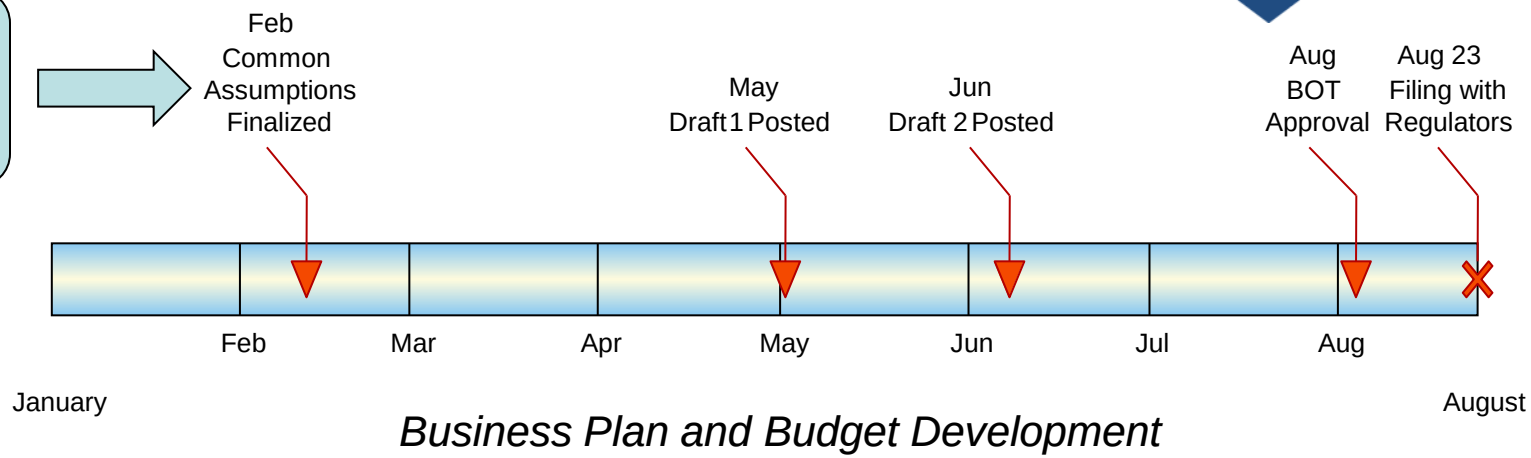
NOTE: *Although the RISC has rated GMD a low-priority item from a reliability risk perspective, this item may change in priority and/or need additional ERO resources allocated, based on future discussions or regulatory directives.*

Recommendations to Board

- Recommend that the Board adopt the strategic prioritization and direct NERC to incorporate these priority rankings into the development of ERO business plans.
- Recommend that the Board direct NERC's Committees to incorporate these priority rankings into their work plans – including empowering committees to stop or defer lower priority work.
- Recommend the Board direct the RISC work with NERC staff and Standing Committee leadership to create a results-driven Reliability Strategy development process that integrates with budget development and overall ERO planning.

Prioritization Must Drive Resource Planning

BOT-Approved RISC Strategic Prioritization



Business Plan and Budget Development

Strategy-Based Business Plan and Budget

3 Year RSDP

OC Strategic Plan

PC Strategic Plan

CIPC Strategic Plan

CCC Work Plan

NERC Goals

Reliability Standards Development Plan

Standing Committee Plans

Department and Employee Goals

Reliability Issue Nominations

Cold Weather Preparedness – October 2012 Meeting	
RISC Recommendation developed, being implemented by Operating Committee and NERC Staff	Resolved
WECC Planning Coordinator – October 2012 Meeting	
Response sent to submitter, advising of alternative courses	Out of Scope
Geomagnetic Disturbance – December 2012 Meeting	
RISC request sent to Operating Committee, Standard Committee, and Geomagnetic Disturbance Task Force; to be discussed further at January RISC meeting	In Progress
Critical Infrastructure Protection – December 2012 Meeting	
Response sent to submitter, identifying issue as out of scope	Out of Scope
Under-Voltage Load Shedding – January 2013 Meeting	
Response sent to submitter, advising of alternative course with PC	Out of Scope
Critical Energy Infrastructure Information – January 2013 Meeting	
Response sent to submitter, identifying issue as out of scope	Out of Scope



Questions ?

The White House

Office of the Press Secretary

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For Immediate Release February 12, 2013

Executive Order -- Improving Critical Infrastructure Cybersecurity

EXECUTIVE ORDER

- - - - - - -

IMPROVING CRITICAL INFRASTRUCTURE CYBERSECURITY

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered as follows:

Section 1. Policy. Repeated cyber intrusions into critical infrastructure demonstrate the need for improved cybersecurity. The cyber threat to critical infrastructure continues to grow and represents one of the most serious national security challenges we must confront. The national and economic security of the United States depends on the reliable functioning of the Nation's critical infrastructure in the face of such threats. It is the policy of the United States to enhance the security and resilience of the Nation's critical infrastructure and to maintain a cyber environment that encourages efficiency, innovation, and economic prosperity while promoting safety, security, business confidentiality, privacy, and civil liberties. We can achieve these goals through a partnership with the owners and operators of critical infrastructure to improve cybersecurity information sharing and collaboratively develop and implement risk-based standards.

Sec. 2. Critical Infrastructure. As used in this order, the term critical infrastructure means systems and assets, whether physical or virtual, so vital to the United States that the incapacity or destruction of such systems and assets would have a debilitating impact on security, national economic security, national public health or safety, or any combination of those matters.

Sec. 3. Policy Coordination. Policy coordination, guidance, dispute resolution, and periodic in-progress reviews for the functions and programs described and assigned herein shall be provided through the interagency process established in Presidential Policy Directive-1 of February 13, 2009 (Organization of the National Security Council System), or any successor.

Sec. 4. Cybersecurity Information Sharing. (a) It is the policy of the United States Government to increase the volume, timeliness, and quality of cyber threat information shared with U.S. private sector entities so that these entities may better protect and defend themselves against cyber threats. Within 120 days of the date of this order, the Attorney General, the Secretary of Homeland Security (the "Secretary"), and the Director of National Intelligence shall each issue instructions consistent with their authorities and with the requirements of section 12(c) of this order to ensure the timely production of unclassified reports of cyber threats to the U.S. homeland that identify a specific targeted entity. The instructions shall address the need to protect intelligence and law enforcement sources, methods, operations, and investigations.

(b) The Secretary and the Attorney General, in coordination with the Director of National Intelligence, shall establish a process that rapidly disseminates the reports produced pursuant to section 4(a) of this order to the targeted entity. Such process shall also, consistent with the need to protect national security information, include the dissemination of classified reports to critical infrastructure entities authorized to receive them. The Secretary



BLOG POSTS ON THIS ISSUE

February 13, 2013 6:39 PM EST

Improving the Security of the Nation's Critical Infrastructure

President Obama issued an Executive Order directing federal departments and agencies to use their existing authorities to provide better cybersecurity for the Nation, efforts that will by necessity involve increased collaboration with the private sector.

February 13, 2013 5:15 PM EST

Open for Questions: The State of the Union and the Economy

Alan Krueger, Chairman of the Council of Economic Advisers, answered questions from the public about President Obama's State of the Union Address in an "Open for Questions" session moderated by Yahoo! Finance. Check it out below.

February 13, 2013 4:55 PM EST

First Lady Michelle Obama hosts a "Beasts of the Southern Wild" Movie Workshop for Students



The stars of the Oscar-nominated drama joined Mrs. Obama to help teach students about the hard work required to create a beautiful movie.

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and the Attorney General, in coordination with the Director of National Intelligence, shall establish a system for tracking the production, dissemination, and disposition of these reports.

(c) To assist the owners and operators of critical infrastructure in protecting their systems from unauthorized access, exploitation, or harm, the Secretary, consistent with 6 U.S.C. 143 and in collaboration with the Secretary of Defense, shall, within 120 days of the date of this order, establish procedures to expand the Enhanced Cybersecurity Services program to all critical infrastructure sectors. This voluntary information sharing program will provide classified cyber threat and technical information from the Government to eligible critical infrastructure companies or commercial service providers that offer security services to critical infrastructure.

(d) The Secretary, as the Executive Agent for the Classified National Security Information Program created under Executive Order 13549 of August 18, 2010 (Classified National Security Information Program for State, Local, Tribal, and Private Sector Entities), shall expedite the processing of security clearances to appropriate personnel employed by critical infrastructure owners and operators, prioritizing the critical infrastructure identified in section 9 of this order.

(e) In order to maximize the utility of cyber threat information sharing with the private sector, the Secretary shall expand the use of programs that bring private sector subject-matter experts into Federal service on a temporary basis. These subject matter experts should provide advice regarding the content, structure, and types of information most useful to critical infrastructure owners and operators in reducing and mitigating cyber risks.

Sec. 5. Privacy and Civil Liberties Protections. (a) Agencies shall coordinate their activities under this order with their senior agency officials for privacy and civil liberties and ensure that privacy and civil liberties protections are incorporated into such activities. Such protections shall be based upon the Fair Information Practice Principles and other privacy and civil liberties policies, principles, and frameworks as they apply to each agency's activities.

(b) The Chief Privacy Officer and the Officer for Civil Rights and Civil Liberties of the Department of Homeland Security (DHS) shall assess the privacy and civil liberties risks of the functions and programs undertaken by DHS as called for in this order and shall recommend to the Secretary ways to minimize or mitigate such risks, in a publicly available report, to be released within 1 year of the date of this order. Senior agency privacy and civil liberties officials for other agencies engaged in activities under this order shall conduct assessments of their agency activities and provide those assessments to DHS for consideration and inclusion in the report. The report shall be reviewed on an annual basis and revised as necessary. The report may contain a classified annex if necessary. Assessments shall include evaluation of activities against the Fair Information Practice Principles and other applicable privacy and civil liberties policies, principles, and frameworks. Agencies shall consider the assessments and recommendations of the report in implementing privacy and civil liberties protections for agency activities.

(c) In producing the report required under subsection (b) of this section, the Chief Privacy Officer and the Officer for Civil Rights and Civil Liberties of DHS shall consult with the Privacy and Civil Liberties Oversight Board and coordinate with the Office of Management and Budget (OMB).

(d) Information submitted voluntarily in accordance with 6 U.S.C. 133 by private entities under this order shall be protected from disclosure to the fullest extent permitted by law.

Sec. 6. Consultative Process. The Secretary shall establish a consultative process to coordinate improvements to the cybersecurity of critical infrastructure. As part of the consultative process, the Secretary shall engage and consider the advice, on matters set forth in this order, of the Critical Infrastructure Partnership Advisory Council; Sector Coordinating Councils; critical infrastructure owners and operators; Sector-Specific Agencies; other relevant agencies; independent regulatory agencies; State, local, territorial, and tribal governments; universities; and outside experts.

Sec. 7. Baseline Framework to Reduce Cyber Risk to Critical Infrastructure. (a) The Secretary of Commerce shall direct the Director of the National Institute of Standards and Technology (the "Director") to lead the development of a framework to reduce cyber risks to critical infrastructure (the "Cybersecurity Framework"). The Cybersecurity Framework shall include a set of standards, methodologies, procedures, and processes that align policy, business, and technological approaches to address cyber risks. The Cybersecurity Framework shall incorporate voluntary consensus standards and industry best practices to the fullest extent possible. The Cybersecurity Framework shall be consistent with voluntary international standards when such international standards will advance the objectives of this order, and shall meet the requirements of the National Institute of Standards and Technology Act, as amended (15 U.S.C. 271 et seq.), the National Technology Transfer and Advancement Act of 1995 (Public Law 104-113), and OMB Circular A-119, as revised.

(b) The Cybersecurity Framework shall provide a prioritized, flexible, repeatable, performance-based, and cost-effective approach, including information security measures and controls, to help owners and operators of critical

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infrastructure identify, assess, and manage cyber risk. The Cybersecurity Framework shall focus on identifying cross-sector security standards and guidelines applicable to critical infrastructure. The Cybersecurity Framework will also identify areas for improvement that should be addressed through future collaboration with particular sectors and standards-developing organizations. To enable technical innovation and account for organizational differences, the Cybersecurity Framework will provide guidance that is technology neutral and that enables critical infrastructure sectors to benefit from a competitive market for products and services that meet the standards, methodologies, procedures, and processes developed to address cyber risks. The Cybersecurity Framework shall include guidance for measuring the performance of an entity in implementing the Cybersecurity Framework.

(c) The Cybersecurity Framework shall include methodologies to identify and mitigate impacts of the Cybersecurity Framework and associated information security measures or controls on business confidentiality, and to protect individual privacy and civil liberties.

(d) In developing the Cybersecurity Framework, the Director shall engage in an open public review and comment process. The Director shall also consult with the Secretary, the National Security Agency, Sector-Specific Agencies and other interested agencies including OMB, owners and operators of critical infrastructure, and other stakeholders through the consultative process established in section 6 of this order. The Secretary, the Director of National Intelligence, and the heads of other relevant agencies shall provide threat and vulnerability information and technical expertise to inform the development of the Cybersecurity Framework. The Secretary shall provide performance goals for the Cybersecurity Framework informed by work under section 9 of this order.

(e) Within 240 days of the date of this order, the Director shall publish a preliminary version of the Cybersecurity Framework (the "preliminary Framework"). Within 1 year of the date of this order, and after coordination with the Secretary to ensure suitability under section 8 of this order, the Director shall publish a final version of the Cybersecurity Framework (the "final Framework").

(f) Consistent with statutory responsibilities, the Director will ensure the Cybersecurity Framework and related guidance is reviewed and updated as necessary, taking into consideration technological changes, changes in cyber risks, operational feedback from owners and operators of critical infrastructure, experience from the implementation of section 8 of this order, and any other relevant factors.

Sec. 8. Voluntary Critical Infrastructure Cybersecurity Program. (a) The Secretary, in coordination with Sector-Specific Agencies, shall establish a voluntary program to support the adoption of the Cybersecurity Framework by owners and operators of critical infrastructure and any other interested entities (the "Program").

(b) Sector-Specific Agencies, in consultation with the Secretary and other interested agencies, shall coordinate with the Sector Coordinating Councils to review the Cybersecurity Framework and, if necessary, develop implementation guidance or supplemental materials to address sector-specific risks and operating environments.

(c) Sector-Specific Agencies shall report annually to the President, through the Secretary, on the extent to which owners and operators notified under section 9 of this order are participating in the Program.

(d) The Secretary shall coordinate establishment of a set of incentives designed to promote participation in the Program. Within 120 days of the date of this order, the Secretary and the Secretaries of the Treasury and Commerce each shall make recommendations separately to the President, through the Assistant to the President for Homeland Security and Counterterrorism and the Assistant to the President for Economic Affairs, that shall include analysis of the benefits and relative effectiveness of such incentives, and whether the incentives would require legislation or can be provided under existing law and authorities to participants in the Program.

(e) Within 120 days of the date of this order, the Secretary of Defense and the Administrator of General Services, in consultation with the Secretary and the Federal Acquisition Regulatory Council, shall make recommendations to the President, through the Assistant to the President for Homeland Security and Counterterrorism and the Assistant to the President for Economic Affairs, on the feasibility, security benefits, and relative merits of incorporating security standards into acquisition planning and contract administration. The report shall address what steps can be taken to harmonize and make consistent existing procurement requirements related to cybersecurity.

Sec. 9. Identification of Critical Infrastructure at Greatest Risk. (a) Within 150 days of the date of this order, the Secretary shall use a risk-based approach to identify critical infrastructure where a cybersecurity incident could reasonably result in catastrophic regional or national effects on public health or safety, economic security, or national security. In identifying critical infrastructure for this purpose, the Secretary shall use the consultative process established in section 6 of this order and draw upon the expertise of Sector-Specific Agencies. The Secretary shall apply consistent, objective criteria in identifying such critical infrastructure. The Secretary shall not identify any commercial information technology products or consumer information technology services under this section. The Secretary shall review and update the list of identified critical infrastructure under this section on an

annual basis, and provide such list to the President, through the Assistant to the President for Homeland Security and Counterterrorism and the Assistant to the President for Economic Affairs.

(b) Heads of Sector-Specific Agencies and other relevant agencies shall provide the Secretary with information necessary to carry out the responsibilities under this section. The Secretary shall develop a process for other relevant stakeholders to submit information to assist in making the identifications required in subsection (a) of this section.

(c) The Secretary, in coordination with Sector-Specific Agencies, shall confidentially notify owners and operators of critical infrastructure identified under subsection (a) of this section that they have been so identified, and ensure identified owners and operators are provided the basis for the determination. The Secretary shall establish a process through which owners and operators of critical infrastructure may submit relevant information and request reconsideration of identifications under subsection (a) of this section.

Sec. 10. Adoption of Framework. (a) Agencies with responsibility for regulating the security of critical infrastructure shall engage in a consultative process with DHS, OMB, and the National Security Staff to review the preliminary Cybersecurity Framework and determine if current cybersecurity regulatory requirements are sufficient given current and projected risks. In making such determination, these agencies shall consider the identification of critical infrastructure required under section 9 of this order. Within 90 days of the publication of the preliminary Framework, these agencies shall submit a report to the President, through the Assistant to the President for Homeland Security and Counterterrorism, the Director of OMB, and the Assistant to the President for Economic Affairs, that states whether or not the agency has clear authority to establish requirements based upon the Cybersecurity Framework to sufficiently address current and projected cyber risks to critical infrastructure, the existing authorities identified, and any additional authority required.

(b) If current regulatory requirements are deemed to be insufficient, within 90 days of publication of the final Framework, agencies identified in subsection (a) of this section shall propose prioritized, risk-based, efficient, and coordinated actions, consistent with Executive Order 12866 of September 30, 1993 (Regulatory Planning and Review), Executive Order 13563 of January 18, 2011 (Improving Regulation and Regulatory Review), and Executive Order 13609 of May 1, 2012 (Promoting International Regulatory Cooperation), to mitigate cyber risk.

(c) Within 2 years after publication of the final Framework, consistent with Executive Order 13563 and Executive Order 13610 of May 10, 2012 (Identifying and Reducing Regulatory Burdens), agencies identified in subsection (a) of this section shall, in consultation with owners and operators of critical infrastructure, report to OMB on any critical infrastructure subject to ineffective, conflicting, or excessively burdensome cybersecurity requirements. This report shall describe efforts made by agencies, and make recommendations for further actions, to minimize or eliminate such requirements.

(d) The Secretary shall coordinate the provision of technical assistance to agencies identified in subsection (a) of this section on the development of their cybersecurity workforce and programs.

(e) Independent regulatory agencies with responsibility for regulating the security of critical infrastructure are encouraged to engage in a consultative process with the Secretary, relevant Sector-Specific Agencies, and other affected parties to consider prioritized actions to mitigate cyber risks for critical infrastructure consistent with their authorities.

Sec. 11. Definitions. (a) "Agency" means any authority of the United States that is an "agency" under 44 U.S.C. 3502(1), other than those considered to be independent regulatory agencies, as defined in 44 U.S.C. 3502(5).

(b) "Critical Infrastructure Partnership Advisory Council" means the council established by DHS under 6 U.S.C. 451 to facilitate effective interaction and coordination of critical infrastructure protection activities among the Federal Government; the private sector; and State, local, territorial, and tribal governments.

(c) "Fair Information Practice Principles" means the eight principles set forth in Appendix A of the National Strategy for Trusted Identities in Cyberspace.

(d) "Independent regulatory agency" has the meaning given the term in 44 U.S.C. 3502(5).

(e) "Sector Coordinating Council" means a private sector coordinating council composed of representatives of owners and operators within a particular sector of critical infrastructure established by the National Infrastructure Protection Plan or any successor.

(f) "Sector-Specific Agency" has the meaning given the term in Presidential Policy Directive-21 of February 12, 2013 (Critical Infrastructure Security and Resilience), or any successor.

Sec. 12. General Provisions. (a) This order shall be implemented consistent with applicable law and subject to the availability of appropriations. Nothing in this order shall be construed to provide an agency with authority for regulating the security of critical infrastructure in addition to or to a greater extent than the authority the agency has under existing law. Nothing in this order shall be construed to alter or limit any authority or responsibility of an agency under existing law.

(b) Nothing in this order shall be construed to impair or otherwise affect the functions of the Director of OMB relating to budgetary, administrative, or legislative proposals.

(c) All actions taken pursuant to this order shall be consistent with requirements and authorities to protect intelligence and law enforcement sources and methods. Nothing in this order shall be interpreted to supersede measures established under authority of law to protect the security and integrity of specific activities and associations that are in direct support of intelligence and law enforcement operations.

(d) This order shall be implemented consistent with U.S. international obligations.

(e) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

BARACK OBAMA

From: Kimberly Mielcarek
To: Kimberly Mielcarek
Subject: NERC Announcement - Response on Cybersecurity Executive Order
Date: Wednesday, February 13, 2013 5:39:36 PM

Announcement

NERC Response on Cybersecurity Executive Order

Announcement | Executive Order

WASHINGTON, DC – Cybersecurity is an issue that NERC takes very seriously. Our mandatory, risk-based cyber standards and Electricity Sector Information Sharing and Analysis Center (ES-ISAC) provide a strong framework for protecting the bulk power system and sharing timely information with industry. We appreciate the emphasis the executive order places on working within existing public/private partnerships, including the Electricity Sub-Sector Coordinating Council (ESCC), which NERC chairs, to increase the flow of cyber and threat information between government and private industry. NERC, in carrying out its responsibilities as the electric reliability organization, looks forward to continuing its work with the Administration, Congress and the industry to further enhance the reliability and security of the North American bulk power system.

For more information or assistance, please contact Kimberly Mielcarek

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC News

November 2012

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NERC Activities in Quarters 1-3, 2012

Headlines

Board Adopts Five Standards, One Interpretation; Thanks Outgoing Staff, Chairs and Board Members

The North American Electric Reliability Corporation's (NERC) quarterly Board of Trustees meeting took place Wednesday in New Orleans. In attendance was Commissioner Cheryl LaFleur, from the Federal Energy Regulatory Commission; and special guest Rod West, executive vice president and chief administrative officer at Entergy, along with industry participants.

In her opening remarks, Commissioner LaFleur spoke to the recent notice of proposed rulemaking on geomagnetic disturbances, saying industry must have a "no regrets" approach to protecting the grid. The proposed rule gives industry flexibility to respond as it sees fit through standards, but the industry must respond.

NERC Board of Trustees Chair John Q. Anderson began the meeting by honoring David Nevius, senior vice president at NERC, for 33 years of service and outstanding contributions to NERC via a resolution. Among many things, Nevius was recognized for his role in developing the framework for the electric reliability organization, his work with the Regions and the Member Representatives Committee and spearheading event analysis on grid events.

NERC's President and Chief Executive Officer Gerry Cauley thanked FERC for approval of the NERC and regional budgets, and recognized Mike Bardee as the new head of FERC's Office of Electric Reliability and Joe McClelland as the head of FERC's new Office of Energy Infrastructure Security.

"The emerging roles, responsibilities and relationships with so many different agencies make a logical case for establishing this new office," Cauley said. "NERC looks forward continued coordination with FERC and this new office."

In moving forward, the electric reliability organization must continue its focused efforts on standards and compliance improvements. The meeting highlighted ongoing efforts of the Standard Process Improvement Group, the Reliability Issues Steering Committee, as well as the new reliability assurance initiative to focus compliance on risk management.

"The path that we previously selected for standards development and compliance will no longer get us, collectively, to where we want to be," Cauley said.

The board adopted five standards: COM-001-2 – *Communications*, COM-002-3 – *Communication and Coordination*, PRC-005-2 – *Protection System Maintenance*, EOP-004-2 – *Event Reporting,* and TOP-006-2 – *Transmission Real-Time Operations,* which was a rapid revision of an existing standard. The board also adopted an interpretation of BAL-002-0.

In other activities, the board adopted two Regional Standards: PRC-006-SPP-01 – *SPP Automatic Underfrequency Load Shedding*, and BAL-002-WECC-1 – *Contingency Reserve.* The board approved the withdrawal of MOD-025-RFC-01 – *Verification and Data Reporting of Generator Gross and Net Reactive Power Capability,* in response to RFC staff determination that no requirement exists for a regional standard. The board also endorsed the recommendations of the Standards Process Input Group for improving the effectiveness and efficiency of the NERC standards development process.

The board thanked Scott Helyer, vice president of Transmission at Tenaska, Inc., for his work as the outgoing chair of the Member Representatives Committee; and Allen Mosher, vice president of Policy Analysis and Reliability Standards at American Public Power Association, for his work as chair of the Standards Committee.

Also serving at their last full board meeting were Chair John Q. Anderson, and board members Tom Berry and Vicky Bailey, whose terms conclude at the end of the year. Fred Gorbet is board chair-elect. The next Board of Trustees meeting is scheduled for February 7 in San Diego.

Response to Passage of Critical Infrastructure Protection Version 5 Standards

The electricity industry passed Version 5 of the North American Electric Reliability Corporation's critical infrastructure protection standards with an overwhelming consensus earlier this week.

"The industry is to be commended for supporting the CIP Version 5 standards with high approval rates," said Gerry Cauley, president and chief executive officer of the North American Electric Reliability Corporation (NERC). "This effort represents significant prioritization from the industry focused on the importance of cybersecurity."

The Version 5 standards leverage lessons learned from previous CIP versions, providing for categorization of BES Cyber Systems commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the bulk electric system. The standards provide increased flexibility in implementing risk mitigation and security to individual entity operations based on function, connectivity, risk and impact.

NERC's Board of Trustees adopted Version 5 of the CIP standards on November 26. The standards now will be filed with the Federal Energy Regulatory Commission for final approval.

For more information on CIP Version 5, see **Standards article below.*

Careers at NERC

Meeting Planner Specialist
Location: Atlanta
Details

Compliance Enforcement Coordinator
Location: Washington, DC
Details

ES-ISAC Cybersecurity Specialist
Location: Washington, DC
Details

CIP Security Specialist
Location: Washington, DC
Details

CIP Compliance Auditor
Location: Washington, DC
Details

CIP Compliance Auditor
Location: Atlanta
Details

Senior Compliance Operations Auditor
Location: Atlanta
Details

Bulk Power System Awareness Engineer
Location: Atlanta
Details

Senior Reliability Engineer (Relay)
Location: Atlanta
Details

Engineer of Reliability Risk Controls
Location: Atlanta
Details

Standards Developer
Location: Atlanta
Details

Administrative Assistant-Reliability Risk Management
Location: Atlanta
Details

Reliability Risk Management

NERC Participates in SERC's Annual System Restoration Drill

SERC Reliability Corporation had their annual System Restoration Drill November 7-8 at Duke Energy headquarters in Charlotte, N.C. For the first time, NERC participated in the drill to add realism and provide a multi-echelon training opportunity for SERC and NERC staffs, allowing both to practice and refine their crisis response procedures.

Unlike recent drills where the restoration scenario has been initiated by a hurricane, this time an earthquake in western South Carolina was the initiating event that caused a widespread blackout, islanding and system separations. Significant GMD activity had been reported in the days leading up to the earthquake, which drove drill participants to work together to determine the true cause of the event while determining their specific restoration plans.

The drill had participation from all four reliability coordinators and balancing authorities, and transmission operators and owners covering the SERC region. While large blackouts, such as this scenario, are rare, it is important to the reliability of the bulk power system to maintain proficiency at quickly and effectively restoring large blackouts.

NERC Staff Facilitates Communications during Hurricane Sandy

Hurricane Sandy made landfall on October 29 near Atlantic City, N.J., and devastated portions of the Mid-Atlantic and Northeastern United States with its unprecedented 1,100-mile wide wind field. Remnants of the storm brought high winds and heavy rainfall across the Midwest, Southeast and Eastern Canada for several days. Sandy forced more than 260 bulk power system facilities out of service, and caused 8.5 million customer outages.

From October 30 through November 8, NERC's Reliability Risk Management department, in conjunction with staff from Reliability*First* Corporation, Northeast Power Coordinating Council and SERC Reliability Corporation, assessed the storm's impacts and the condition of the bulk power system and developed, maintained and shared an accurate wide-area view of the bulk power system.

Eight governmental agency update conference calls took place for key stakeholders including FERC, Department of Energy, Department of Homeland Security, Nuclear Regulatory Commission, Federal Emergency Management Agency and Canada National Energy Board; sixteen internal updates were issued for NERC staff updates.
Of note, RFC coordinated for PJM Interconnection representatives, and NPCC coordinated for New York ISO and ISO-New England representatives, in the government update calls to add value to the discussion and address technical questions from government agency staff.

Initial feedback from government agencies has been uniformly positive and appreciative of the timely, accurate and detailed information provided by the electric reliability organization.

NERC's RRM staff also used the experience to identify a number of enhancements to their internal procedures used for crisis response.

Standards

SPIG Recommendations Posted for Industry Comment and Successive Ballot for Standard Processes Manual Revisions

NERC posted the latest draft of Standard Processes Manual revisions on November 21 for industry comment and successive ballot through December 20. The revisions were developed by the Standards Committee Process Subcommittee and are intended to implement Standards Process Input Group (SPIG) recommendations from the April 2012 SPIG report.

An initial ballot of the second draft of the proposed revisions to the Standard Processes Manual concluded on October 12 and received a 63 percent approval. The Standards Committee Process Subcommittee and Standards Committee have reviewed comments

submitted during the associated comment period and made the following substantive changes in response:

- **VRFs, VSLs, Measures and RSAWs**: The majority of the comments recognized the burden that development of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) have on drafting teams and supported the development of potential alternatives. Comments also expressed support for drafting team participation in developing Reliability Standard Audit Worksheets (RSAWs). The development and implementation of both of these items will require collaboration among the Standards Committee, NERC standards staff, and NERC and regional compliance programs. Therefore, the Standards Committee Process Subcommittee is actively working with NERC and regional enforcement staff to establish a consensus on the concepts for alternatives to VRFs and VSLs. In the same vein, NERC's compliance program is working with regions and stakeholders to develop and implement the Reliability Assurance Initiative, and as this effort evolves, the Standards Committee and NERC standards staff will leverage opportunities to align drafting teams and compliance staff to ensure that the intent of drafting teams is captured in approaches to monitoring compliance.

  While these concepts are further developed, Measures, VRFs and VSLs will continue to be drafted by the drafting teams, and a non-binding poll of VRFs and VSLs will continue to be conducted consistent with current process.
- **Treatment of "no" votes during a final ballot:** A concern was identified about how negative ballots cast in a final ballot would be treated since there is no obligation in the current Standard Processes Manual to accept comments during a recirculation ballot, and in the proposed revisions to the Standard Processes Manual there is no comment period associated with a final ballot. To address this concern, language has been added to section 4.11 to clarify that all "no" votes submitted in a final ballot will count toward determination of both the quorum and consensus. A new footnote 24 has also been inserted in section 4.11, which reads: *The Final Ballot is used to confirm consensus achieved during the Formal Comment and Ballot stage. Ballot Pool members voting negative on the Final Ballot will be deemed to have commented or supported the comments of other groups during prior Formal Comment periods.*
- **Section 16.0 Waiver Provision:** In response to stakeholder concerns regarding transparency, openness and due process protections, the Standards Committee Process Subcommittee incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. The Standards Committee Process Subcommittee also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight and Technology Committee.

When the comment and ballot period concludes, the Standards Committee Process Subcommittee will review all comments received and determine what revisions are necessary to finalize the Standard Processes Manual. If no significant changes are made, the Standard Processes Manual will be posted for a final recirculation ballot and, if approved by the stakeholder body, presented to the NERC Board of Trustees for approval.

All project-related documents are posted on the SPM project page and a webinar to review the changes is scheduled for 11 a.m. Eastern December 6.

The Standards Committee, its subcommittees and NERC staff are grateful for the industry participation and input to develop Standard Processes Manual revisions that result in efficient use of industry resources to develop high-quality, results-based standards in a timely manner. Collectively, these

proposed changes create a number of efficiencies that will be beneficial to drafting teams, NERC staff and all stakeholder participants in the standard development process, but NERC staff will continue to work toward a leaner, more efficient standards process. To that end, at its November 7 meeting in New Orleans, NERC's Board of Trustees adopted a four-part resolution (item 7ei of the posted agenda package) to move forward in improvements to the standards development process with increased accountability in standards development, modified resourcing of standards development teams, better work flow management, and enhanced work plans to aggressively pursue work that is directly related to reliability risks.
NERC will keep stakeholders informed and encourage participation as it pursues these additional improvements.

CIP Version 5 Standards Adopted by NERC Board of Trustees

Ten CIP standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1), an associated implementation plan, and a set of new and revised NERC Glossary terms were adopted by the NERC Board of Trustees in a conference call on November 26.

The standards and associated documents were approved with at least a 78 percent approval rating in recirculation ballots that ended on November 5, and nine of 12 ballots passed with more than 90 percent approval. The non-binding poll for the associated VRFs and VSLs for all 10 CIP standards concluded on November 13 with an 83.82 percent approval.

These standards represent a significant milestone in the industry's continuing emphasis on the importance of robust, reliability-related cyber security standards for the bulk power industry and they represent significant progress in mitigating cyber risks to the Bulk Electric System (BES).

The Project 2008-06 Cyber Security Order 706 standard drafting team was charged with addressing all remaining standards-related issues from FERC Order No. 706 in this phase. The recently approved NERC Version 5 CIP Reliability Standards provide a cyber security framework for the categorization and protection of Bulk Electric System (BES) cyber systems to support the reliable operation of the BES.

These standards recognize the differing roles of each entity in the operation of the BES, the criticality and vulnerability of the cyber systems needed to support BES reliability, and the risks to which they are exposed. Key strategic advancements in CIP Version 5 include consideration and incorporation of implementation and audit lessons from past versions, flexibility for entities to tailor security in a manner best suited to their own operations, and a transition from the "in or out" classification of Critical Assets and their associated Critical Cyber Assets to a "Low-Medium-High" impact-based categorization of BES Cyber Systems.

NERC and the drafting team thank all industry participants for their feedback and dedicated work throughout this process.

NERC Standards and Compliance 101 Webinar Posted

The NERC Standards and Compliance 101 webinar and slide deck from the October 23-25 Standards and Compliance Workshop in Atlanta have been posted to NERC's webinar page, where they will be available until the next workshop in Spring 2013.

The 90-minute presentation provides a brief overview of NERC and in-depth information on NERC's standards and compliance programs. It is designed to give individuals new to NERC a primer on NERC as a whole, its standards and compliance programs and processes, and opportunities for stakeholder participation. **Note:** The webinar was recorded in October 2012 and the information included is subject to change.

For any follow-up questions related to standards, contact Mallory Huggins. For follow-up questions related to compliance, contact Matt Gibbons.

CIP Interpretation Drafting Team Thanked

NERC would like to thank members and observers of the CIP Interpretation drafting team for their exemplary work in 2012. In particular, NERC would like to recognize the leadership and guidance of co-chairs Tim Conway from NIPSCO and Scott Miller from MEAG.

Of the eight outstanding projects in 2012, three have been filed with FERC, one is in initial ballot, three are in a 30-day formal comment period, and one is under active development.
The drafting team's next meeting is from 1-4 p.m. December 13 in Atlanta. The team's projects can be found on the drafting team's page.

Upcoming Standards Webinars

- Project 2007-02: Operating Personnel Communications Protocols (COM-003) Industry Webinar – 1:30-3:30 p.m. Eastern November 27 (Register)
- Project 2010-13.2: Phase 2 of Relay Loadability: Generation (PRC-025) Industry Webinar –2-4 p.m. Eastern December 13 (Register)

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination
Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

Project 2007-12 Frequency Response
Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

Filings

NERC Filings to FERC

(click on the link for full filing)

November 21, 2012

Petition for Approval of Proposed Reliability Standard VAR-002-2b

NERC submits a petition for approval of VAR-002-2b— Generator Operation for Maintaining Network Voltage Schedules, approval of the proposed Reliability Standard, the associated implementation plan, Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and retirement of the currently effective Reliability Standard VAR-002-1.1b. *Docket No. RD13-2-000*

November 26, 2012

Comments of NERC in Response to NOPR on PRC-006-NPCC-01

NERC submits comments in response to FERC's September 20, 2012 Notice of Proposed Rulemaking regarding the proposed regional Reliability Standard PRC-006-NPCC-1 (Automatic Underfrequency Load Shedding). *Docket No. RM12-12-000*

NERC Filings in Canada, click here

(click on the link above for full filing)

NERC 3rd Quarter 2012 Application for Approval of Reliability Standards (Nova Scotia)

NERC submitted its Third Quarter 2012 Application for Approval of Reliability Standards to the Nova Scotia Utility and Review Board. This filing requested that the standards approved by FERC in the 3rd Quarter 2012 become effective in the province of Nova Scotia according to the December 2006 MOU between NERC and the NSUARB. This filing is made each quarter.

Quarterly Update

NERC has been actively working to deliver key results linked to the Corporate Strategic Goals during the first two quarters of 2012. The following list of electric reliability organization (ERO) activities spotlight two areas: reliability initiatives addressing emerging reliability risks, and activities striving to improve bulk power system reliability. For questions, contact Mike Moon, senior director of Reliability Risk Management.

Quarter 1 – 2012 (January – March)

Compliance Enforcement

- NERC staff spoke at a webinar conducted by the Edison Electric Institute, January 19
- NERC staff spoke at a panel presentation in the National Association of Regulatory Utility Commissioners' winter meeting, February 5
- CEI information update webinar, February
- ERO auditor workshop, February
- NERC staff spoke at a meeting of the Northwest Public Power Association, March 1
- NERC staff spoke at the North American Generator Forum webinar, March 27

Critical Infrastructure

- Cyber Risk Preparedness Assessment Exercise with undisclosed Entity, February 21
- Electricity 101 for Federal Partners. NERC hosted workshop to discuss response, recovery and risk to the BPS, March 21
- National Level Exercise 2012 DHS "tabletop" exercise, ES-ISAC engaged to describe unfolding cyber risk, March 25
- ES-ISAC workshop with the Royal Canadian Mounted Police to discuss threats, vulnerabilities, and risk to BPS, March 27

Reliability Assessment and Performance Analysis

- Transmission System Information Networks (TSIN) move to new website location hosted by NAESB, February
- Technical report released: Loss of Reactive Power, Voltage Instability Most Likely Outcome from GMD, February
- Event Driven Index report approved by NERC's Planning Committee, March

Reliability Risk Management

- Published six Lessons Learned from events on the bulk power system
- Hosted a webinar on the Southwest cold snap recommendations, January 23
- Gave presentation on Southwest cold snap recommendations at Plugging into Natural Gas conference in Portland, Ore., January 25
- Hosted a webinar on the ERO Event Analysis Process Document, March 15
- Hosted a webinar on FAC Alert Recommendations, March 20
- Conducted Improving Human Performance on the Grid conference, March 27-29

Standards

- Hosted Order 754 - Data Request webinar, January 5
- Hosted Order 754 - Data Request - The Study of Single Point of Failure webinar, January 20
- Hosted February 2011 Cold Snap Event Recommendations webinar, January 23

Quarter 2- 2012 (April – June)

Compliance Enforcement

- NERC staff presented during the Energy Bar Association's Compliance and Enforcement Committee and Georgetown University Law Center's Energy Enforcers and Defenders Forum, April 2
- NERC staff presented at the Annual Conference of the National Hydropower Association, April 17
- NERC staff presented at the EEI Reliability Executive Advisory Committee, April 25
- NERC staff presented at the Energy Bar Association's annual meeting, April 26
- NERC staff presented at the NPCC Compliance workshop, May

Compliance Operations

- Hosted the Standards and Compliance Workshop in San Diego, April
- Released the 2011 Annual CMEP report
- Finalized the 2013 Annual Implementation plan.
- Worked with industry to refine risk-based compliance monitoring, including finalizing entity impact evaluation for industry comment, Compliance and Certification Committee working group and Registered Entity focus groups; and integrated consideration of internal controls into standards to move away from zero-tolerance standards.

Critical Infrastructure

- Sufficiency Review Program (SRP)/CIP V4-V5 Outreach Session with Suez to discuss Risk-Based Assessment Methodologies and Critical Assets, May 7
- NERC/NIST/DOE published *Electricity Sub-sector Cyber Security Risk Management Process Guideline*, May 23
- National Level Exercise 2012 DHS exercise, ES-ISAC engaged to describe potential risk (in scenario) to bulk power system, and exercise (draft) NERC Crisis Response Plan June 4
- Critical Infrastructure Protection Committee (CIPC)- brief from DOE highlighting Risk Management and the White House Electricity Sector Cyber Security Capability Maturity Model (ES-C2M2), June 20

Reliability Assessment and Performance Analysis

- NERC, EPRI release open source code to analyze geomagnetically induced currents, April
- NERC participated in FERC technical conference on geomagnetic disturbances, April
    - NERC files Geomagnetic Disturbances Impact to the Bulk Power System with FERC for technical conference
- Web-based Generator Availability Data System to support data collection, April
- Development of new Reliability Risk Controls program, April
- State of Reliability report offers historical reference on bulk power system trends, May
- Web-based spare equipment database collection begins operation, May
- NERC releases two reports focused on high-impact, low-frequency risks: severe impact resiliency and cyber attack, May
- 2012 Summer Reliability Assessment delivered, May
- In conjunction with NERC Standards, hosted two technical conferences on frequency response, May
- Hosted Model Validation workshop, May
- Developed preliminary Reliability Risk Register and initial risk identification, May
- Developed 2012 Pilot Probabilistic Assessment for Long-Term Reliability Assessments, June
- Reviewed prior Reliability Risk Controls program; reevaluated concepts and developed new Reliability Risk Analysis and Control program, June
- Developed internal Reliability Risk Analysis and Control vision document, June
- Revised preliminary Reliability Risk Register, June

Reliability Risk Management

- Published Industry advisory on Preventable EMS and SCADA events, April 10
- Published joint FERC/NERC report on the September 8, 2011 Southwest Blackout Event, May 1
- Published joint FERC/NERC report on the October 29-20, 2011 Northeast Snowstorm, May 31
- Published seven Lessons Learned from events on the Bulk Power System

Standards

- Hosted the Standards and Compliance workshop in San Diego, April

- Hosted draft CIP Standards Version 5 webinar, April 10
- Developed definition of Adequate Level of Reliability, May 23
- Developed draft standards - COM-003-1 and COM-002-3, June 7
- Posted Order No. 754 - Data Request - The Study of Single Point of Failure - Draft 2, June 7
- Revised NERC Standards Processes Manual to Implement SPIG, June 25

Quarter 3- 2012 (July – September)

Compliance Enforcement and Operations

- Hosted Compliance Enforcement Initiative industry webinar, July 11
- ERO Auditor Workshop, September 20
- Industry Workshop, September 21
- NERC Staff presented at 17 Regional Entity Industry Compliance
- Completed two ERO CEA staff training workshops
  - Completed two industry Compliance Seminars
- Completed four lead auditor training (including specialized training for Certification Team Leads)
- Completed two Compliance Investigations process training sessions for NERC and Region staff (February, September 2012)
- Provided a day-long training session of the NERC CI process to first meeting of the newly established Canadian Federal-Provincial-Territorial Electricity Working Group Enforcement Sub-Group staff in Toronto in October 2012
- Earl Shockley and Ken Lotterhos also provided a three-hour overview of the ERO Enforcement Process, NERC's evolving approach to compliance, and planned CEI White Paper to Canadian Federal-Provincial-Territorial Electricity Working Group Enforcement Sub-Group staff in October 2012. This briefing was done the day following the Canadian CI training session indicated above.
- Earl Shockley–
  Represented NERC at the hearings conducted by the California State legislature review of the September 8, 2011 Southwest Blackout

  Represented NERC at the Cold Snap panels conducted by FERC in October 2012 in Texas and New Mexico
- Completed the 2013 CMEP Implementation Plan
- All Registration Letter templates posted on NERC website
- Certification Letter templates covering the entire Certification Process submitted to ORCS and Regions for review and comments. This promotes both consistency and transparency
- Formalized the Certification Review process for certified entities that have reviewable changes to their operational or structural characteristics.
- Compliance Analysis Reports (CARs)
  - Compliance Analysis Report: CIP-005
- Compliance Application Notices (CANs)
  - CAN-0008: PRC-005 R2: Basis for First Maintenance and Testing Date (Revised)
  - CAN-0011: PRC-005 R2: Interval Start Date for New Equipment (Revised)
  - CAN-0012: Completion of Periodic Activity Requirements During Implementation Plan (Revised)
  - CAN-0043: PRC-005: Protection System Maintenance and Testing Evidence (Revised)

Critical Infrastructure

- Completed three Sufficiency Review Program (SRP)/CIP V4-V5 Outreach Sessions (July 18, August 28, September 11); four total SRPs completed; six additional SRPs scheduled
- Conducted Aurora briefings as part of the SRPs; completed bi-annual Aurora update report and submitted to FERC, August 14, 2012

- Conducted a Cyber Risk Preparedness Assessment, June 29, 2012
- Began piloting threat indicators search tool for ES-ISAC analytics and a new system for tracking incident reports submitted to the ES-ISAC
- Contributed to technical aspects of CIP Standards in preparation for posting and ballot; meetings on July 10, August 14, and other calls
- Finalized draft of Crisis Action Plan with other NERC department representatives
- Grid Security Conference 2012: over 220 registered attendees by September 30; 28 speakers invited and confirmed; three training sessions scheduled
- Reviewed the Department of Energy Cybersecurity for Energy Delivery Systems programs and projects for relevancy and applicability to the Electricity Sub-sector, July 24
- Participated in CCWG Meeting, August 9
- Hosted ERO Auditor workshop and CIP Auditor Breakout Workshop in Atlanta, September 18-20
- Developed Cyber Vulnerability Assessment presentation with Encari for CIPC and posted to NERC site
- Spoke to an EPRI/Generator Forum conference on CIP Standards, July 11
- CIP Compliance and Monitoring:
  - Participated on six CIP Compliance Audits and provided compliance guidance to regions
    - East Kentucky Power Cooperative (SERC), Lexington, KY: July 16-August 3
    - Grand River Dam Authority (SPP RE), Locust Grove, OK: August 27-30; October 1-12
    - First Energy (RFC), Fairmont, WV: September 24-28
  - Presented CIP FFT Guidance to Regions at ENSWG
  - Presented V3-V4 Transition Plan to CCWG and worked closely with industry to address "bright-line" transition issues
  - Presented Internal Controls Framework at ERO Compliance Auditor Training, September 18-20
  - Presented at SERC's CIP Compliance Workshop
  - Presented at RFC's Compliance Workshop
  - Worked with the Regions' Technical Feasibility Exception (TFE) Managers to prepare the TFE annual report that was filed with FERC on September 28
  - Led the TFE Managers' meeting in Atlanta, September 20
  - Worked with the Regions and NERC Legal to develop proposed revisions that streamline the Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards (Appendix 4D to NERC's Rules of Procedure)
  - Participated in the quarterly CCWG meeting at NPCC in New York, August 8-9
  - Attended ASIS/ISC(2) security conference in Philadelphia, September 10-13
- Critical Infrastructure Protection Committee (CIPC):
  - Conducted a CIPC Workshops for industry education/training, September 18
  - Supported the Compliance Ops and CANS initiatives through the Compliance and Enforcement Input WG
  - Completed a CIPC review with HITF on of the Coordinated Action Plan to assign tasks for addressing High Impact Low Frequency Events, September 18

Reliability Assessment and Performance Analysis

- Assessment of Extended Los of Space-Based Positioning, Navigation and Timing
  - ESCC Review: July 17, 2012
  - http://www.nerc.com/docs/escc/Assessment%20of%20the%20extended%20loss%20of%20space-based%20positioning,%20navigation%20and%20timing.pdf
- IVGTF Task 1-3: *Interconnection Requirements for Variable Generation*
  - PC Approval, September
  - Website Release, September 28
- RISC Charter approved by the Board of Trustees, August 2012
- FERC Order 754 Data Request for the Interpretation of NERC Standard TPL-002-0a for PacifiCorp
  - Released to Industry on schedule, September 1, 2012
  - Link: https://www.nerc.net/Order754/Default.aspx
- Disseminated Governor Survey data to regions for comparison with power flow and dynamics model
- Collaborative effort with North American Transmission Forum (NATF) on instructional materials for transmission owners (TOs) and generator owners (GOs) on generator dynamics modeling.

Reliability Risk Management / Training

- Hosted Facility Ratings Alert Recommendation Webinar, October 3
- Published Alerts:
  - Alert A-2012-09-12-01 (Shamoon) was published on September 12
  - Alert A-2012-10-04-01 (Telvent network intrusion) was published on October 4
  - NERC's Communication Update: New 24-Hour Emergency Hotline Phone/Email Contact Update and Compliant Hotline Information
- Presentation of Best Practices from the Texas Cold Snap Event from EAS to OC, September 18
- WECC Trainers Workshop in San Diego, July 25
- Cause Analysis Course Atlanta, July 31
- Published NERC Cause Coding Assignment Process, July 31
- Cause Analysis and Data Workshop Atlanta, August 1-2
- MISO's Emergency Operating Plan Coordination Workshop in Minneapolis/St. Paul, August 7
- NPCC Cause Analysis Course in New York, August 9
- ATC Cause Analysis Course and HP Update in Milwaukee, Wis., August 13-14
- MISO's Emergency Operating Plan Coordination Workshop in Carmel, Ind., August 15
- EPRI Power Switching Safety and Reliability Conference in Seattle, August 27-28
- Cause Analysis Course MRO in Minneapolis/St. Paul, September, 12-14
- OC/PC/CIPC in St. Louis, September 17-19
- EA supported RAPA with the 2012-13 Winter Reliability Assessment Data Request
- Posted four Lessons Learned from the Southwest cold snap on, September 12

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC News

December 2012

Headlines

NERC's Response to FERC Approval of Bulk Electric System Definition

Canada

NEB Issues General Order on Standards

Reliability Assessment and Performance Analysis

NERC Educates Japanese Contingent on ERO Structure, Activities

Standards

Board of Trustees Adopts Standards Development Plan, Other Items

FERC Approves Revised Definition of Bulk Electric System

Standard Processes Manual Revisions Achieve Approval in Successive Ballot

Order 754 Upcoming Events

Role of Technical Committees in Transforming Reliability Standards

Save the Dates: NERC's 2013 Standards and Compliance Workshops

Three New Standards Developers Join NERC

Standard Drafting Team Vacancies

NERC Filings

Documents Filed with FERC and/or Canada during the Month

Careers

NERC Seeks Talented Professionals

Headlines

NERC's Response to FERC Approval of Bulk Electric System Definition

The North American Electric Reliability Corporation (NERC) is pleased with the Federal Energy Regulatory Commission's (FERC) action on the Bulk Electric System Definition (on December 20), and looks forward to reviewing the final order. As noted by FERC, this complex issue was completed in two years and demonstrates cooperation and coordination between NERC, FERC and the industry. NERC remains committed to developing effective standards in a timely manner to ensure the reliability of the bulk power system. [FERC release][LaFleur statement]

Canada

NEB Issues General Order on Standards

The National Energy Board of Canada issues a General Order for Electricity Reliability Standards on December 6 that gives all nine Canadian jurisdictions authority to make reliability standards mandatory and enforceable. This completes a process begun in 2002, with Ontario becoming the first jurisdiction to adopt NERC standards as mandatory.

While the provincial structures vary considerably, the significant objective of having a framework of common, mandatory reliability standards has now been achieved between the United States and Canada.

Also significant was a meeting hosted by the Ontario Independent System Operator in October. The meeting was the first of Canadian jurisdictional authorities exercising compliance and enforcement duties. Established as a subgroup of the Federal/Provincial/Territorial Electricity Working Group, its inaugural session included training provided by NERC on the conduct of investigations.

Reliability Assessment and Performance Analysis



NERC Educates Japanese Contingent on ERO Structure, Activities

A group of Japanese power engineers visited NERC's headquarters in Atlanta on December 18 as part of a Power Systems and Energy Course (PSEC) sponsored by GE Energy.

The group visited NERC in an effort to learn about the reliability of the North American power system and about NERC's history. The group's goal is to advance the deregulation of Japan's power system and to possibly create an electric reliability organization in their country.

Participants represented different companies from the Japanese power system. RAPA Vice President and Director Herb Schrayshuen greeted the guests and gave an overview of NERC and its Standards process, while John Moura, associate director of Reliability Assessment, gave a presentation on the reliability and accountability of NERC.

There was much discussion between participants, with the meeting concluding with a tour of NERC's situation awareness room.

Standards

Board of Trustees Adopts Standards Development Plan, Other Items

NERC's Board of Trustees approved the *Reliability Standards Development Plan 2013-2015* on December 19. Developed by NERC staff in conjunction with members of the Standards Committee, the plan represents a revision of NERC's approach to managing the standards development workload. The plan establishes the goal of transitioning the current body of standards to a set of clear, concise standards that ensure the reliability of the bulk power system, while bringing NERC up-to-date on its obligations to address regulatory directives and conduct five-year reviews of standards. Meeting the objectives of the plan requires a disciplined project management approach and review of current processes, including streamlining the standards development process, equipping standards drafting teams, and developing project management plans.

The Board also adopted BAL-001-1: Real Power Balancing Control Performance (a WECC Regional variance of BAL-001-0.1a), BAL-004-WECC-02: Automatic Time Error Control, and proposed revisions to a set of outstanding VRFs and VSLs.

The Board directed NERC to file the plan, the BAL standards, and the revised VRFs and VSLs with applicable regulatory authorities.

FERC Approves Revised Definition of Bulk Electric System

The Federal Energy Regulatory Commission approved a revised definition of Bulk Electric System (BES) through an order on December 20, along with associated revisions to NERC's Rules of Procedure, which create an exception process to add elements to or remove elements from the BES definition, an application form titled "Detailed Information to Support an Exception Request," and an implementation plan. The definition establishes a bright-line threshold that includes all facilities operated at or above 100kV and ensures consistency across all Regions in distinguishing between BES and non-BES elements and facilities.

A second phase of the BES definition project was initiated to develop appropriate technical justification for refinements to the definition that were suggested by stakeholders during Phase I, and to refine the definition as technically justified. More information about Phase II is available on the project page.

Standard Processes Manual Revisions Achieve Approval in Successive Ballot

A successive ballot for the Standard Processes Manual revisions proposed in order to implement Standards Process Input Group recommendations concluded on December 20. The latest revisions – which focused on refining changes with respect to Measures and Reliability Standard Audit Worksheets, the treatment of "no" votes during a final ballot, and the Section 16.0 waiver provision – earned 84 percent approval from the ballot body.

The Standards Committee Process subcommittee subteams will review all comments and determine which revisions are necessary to finalize the SPM. If no significant changes are made, the manual will be posted for a recirculation ballot and, if approved by the stakeholder body, presented to the NERC Board for approval. Additional documentation is available on the project page.

Order 754 Upcoming Events

NERC is launching a new application to support the Order 754 data request. Transmission Planners who submit data in response to the data request have an opportunity to register in January 2013. In February 2013, registered Transmission Planners will have the ability to access the new application to submit data for the collection periods. Watch for webinar dates and times in January to learn more about the registration and data entry process.

The data request was developed in accordance with the NERC Rules of Procedure, Section 1600 — Request for Data or Information and was approved by the NERC Board on August 16, and is available on the

Order 754 project page. Transmission Planners are encouraged to periodically check the project page for information and for appropriate data submittal links, when made available. Entities with questions may contact NERC at DataRequest754@nerc.net.

Role of Technical Committees in Transforming Reliability Standards

NERC's Operating, Planning, and Critical Infrastructure Protection Committees and their respective subcommittees and working groups have traditionally provided NERC with valuable technical and hands-on expertise. NERC appreciates all the time spent by committee members and participants in supporting Reliability Standards activities in 2012.

The successful implementation of NERC's *Reliability Standard Development Plan 2013-2015* depends on the continued hard work of committee participants. While NERC's approach to implementation of the plan calls for significant engagement of these industry-based technical committees, this engagement is not new; historically, the engagement of the committees has been central to NERC's mission and contributed to the documents that provided the foundation for today's reliability standards.

It is vital for NERC's standard development process to be rooted in industry expertise and practical technical experiences. The industry technical brain trust for planning, operations, and critical infrastructure protection is embodied in the leaders that participate in NERC's technical committees. Increased engagement between the Standards Committee and these other important technical committees will ensure that reliability standards are technically sound, while building industry consensus as NERC accelerates the transformation of the current standards to a body of world-class standards that ensures the reliability of the bulk power system.

Save the Dates: NERC's 2013 Standards and Compliance Workshops

NERC will host two Reliability Standards and Compliance Workshops this year: March 19-21 in St. Louis and September 24-26 in Atlanta. Both will offer a remote option for stakeholders unable to attend in person. Additional information about the March workshop will be issued in January.

Three New Standards Developers Join NERC

In the October 2012 issue of NERC News, NERC announced the restructuring of the Standards Department to form three teams of standard developers focused on transforming to a world-class, results-based standards body of standards that ensure the reliability of the bulk power system. Since October, NERC's Standards department has added three new standards developers to support these teams:

Mark Olson joined NERC in October. Mark recently concluded a career as an officer in the U.S. Navy, where he served in various positions related to the operations and management of surface ships and naval personnel. He has a master's degree in electrical engineering from the Naval Postgraduate School and a bachelor's degree from the U.S. Naval Academy.

Erika Chanzes joined NERC in November. Previously, she worked as a quality assurance specialist for Carley Corporation, a company specializing in the development of training solutions for the Department of Defense. Erika has a bachelor's degree in English and writing from Rollins College.

Soo Jin Kim joined NERC in December. Prior to joining NERC, Soo Jin was an associate at Troutman Sanders LLP in Washington, DC, in their Federal Regulation of Electricity and Gas Practice group. Soo Jin has a bachelor's degree in economics and English from the University of Georgia and J.D. from American University.

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for the following vacant appointment may submit a self-nomination form to sarcomm@nerc.com. More instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination
Seeking an individual from a Canadian entity who has experience in coordination of protection systems (new installations and revisions).

Filings

NERC Filings to FERC
(click on the link for full filing)

December 11, 2012
Reply Comments of NERC in response to NOPR on Regional Reliability Standard PRC-006-NPCC-1
NERC provides reply comments in response to the comments submitted on November 26, 2012, on FERC's September 20, 2012, Notice of Proposed Rulemaking ("NOPR") regarding the proposed regional Reliability Standard PRC- 006-NPCC-1 (Automatic Underfrequency Load Shedding). *Docket No. RM12-12-000*

December 21, 2012
Comments of NERC in response to NOPR on Transmission Vegetation Management Standard FAC-003-2
NERC submits comments in response to the October 18, 2012 Notice of Proposed Rulemaking proposing to approve Reliability Standard FAC-003-2. *Docket No. RM12-4-000*

December 31, 2012
Petition for Approval of Proposed Reliability Standard EOP-004-2 - Event Reporting
NERC submits a petition for approval of standard EOP-004-2 - Event Reporting. The proposed Reliability Standard provides a comprehensive approach to reporting disturbances and events that have the potential to impact the reliability of the Bulk Electric System in accordance with several Commission directives. *Docket No. RD13-_-000*

Informational Filing of NERC of Reliability Standards Development Plan 2013-2015
NERC submits the Reliability Standards Development Plan: 2013-2015 (RSDP). The RSDP will: 1. Serve as a management tool to guide and coordinate the development of Reliability Standards and provide benchmarks for assessing progress; 2. Serve as a communications tool for coordinating standards development work with applicable governmental agencies in the United States and Canada and for engaging stakeholders in Reliability Standards development activities; and 3. Provide a basis for developing annual plans and budgets for the NERC Reliability Standards program. *Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000*

NERC Filings in Canada, click here
(click on the link above for full filing)

There were no Canadian filings this month.

Careers at NERC

Meeting Planner Specialist
Location: Atlanta
Details

Bulk Power System Awareness Engineer
Location: Atlanta
Details

Compliance Enforcement Coordinator
Location: Washington, DC
Details

Senior Compliance Operations Auditor
Location: Atlanta
Details

ES-ISAC Cybersecurity Specialist
Location: Washington, DC
Details

CIP Security Specialist
Location: Washington, DC
Details

CIP Compliance Auditor
Location: Washington, DC
Details

CIP Compliance Auditor
Location: Atlanta
Details

Senior Reliability Engineer (Relay)
Location: Atlanta
Details

Senior Web Developer
Location: Atlanta
Details

Engineer of Reliability Risk Controls
Location: Atlanta
Details

Senior Performance and Analysis Engineer
Location: Atlanta
Details

Senior System Analysis and Performance Engineer
Location: Atlanta
Details

Standards Developer
Location: Atlanta
Details

Administrative Assistant-Reliability Risk Management
Location: Atlanta
Details

Continuing Education Program Coordinator
Location: Atlanta
Details

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC News

January 2013

Headlines

FERC Approves Settlement on NERC 2012 Performance Audit

NERC Names New Chief Operating Officer, Vice President for Reliability Assessment and Performance Analysis

Reliability Risk Management

NERC Launches New Version of Situation Awareness Tool

Enhancements made to System Operator Certification and Continuing Ed Database

NERC Filings

Documents Filed with FERC and/or Canada during the Month

Careers

NERC Seeks Talented Professionals

Standards

Stakeholders Approve BAL-003-1

Register for Webinar on Generator Relay Loadability

Piloting the Cost Effective Analysis Process

Paragraph 81 Recirculation Ballot Results and Next Steps

Update on Strategic Improvements to Standards Development

Update on Order No. 754 Status

Standards Committee Accepting Nominations for Special Election

Register for NERC's Spring 2013 Standards and Compliance Workshop

Register Now for the Communications in Operations Conference

Two New Standards Developers Join the Standards Department

Standard Drafting Team Vacancies

2012 ERO Update

NERC Activities in 2012

Headlines

FERC Approves Settlement on NERC 2012 Performance Audit

The Federal Energy Regulatory Commission (FERC) approved a settlement between its Office of Enforcement and the North American Electric Reliability Corporation (NERC) on January 16 that resolved all issues related to the findings and recommendations in Enforcement's 2012 performance audit of the electric reliability organization.

"This settlement will help us at the Commission, and the industry through NERC, move on with the important work of overseeing the reliability of the nation's bulk electric system," FERC Chairman Jon Wellinghoff said. "Implementing these improvements will help to keep the focus on reliability."

"We are pleased to have been able to reach agreement with the Commission on the audit recommendations," said Gerry Cauley, president and chief executive officer at NERC. "As a learning organization, NERC appreciates the value of an external audit in improving the electric reliability organization's internal processes and procedures. A strong and effective ERO supports our overall mission of ensuring the reliability of the bulk power system."

The performance audit, commenced in August 2011 and conducted by Enforcement's Division of Audits, evaluated NERC's budget formulation, administration and execution, focusing on the costs and resources used to achieve its program objectives. The May 4, 2012 final audit report made findings of fact and 42 recommendations in 11 broad areas, including the NERC budget process, compensation and expenses, and NERC's role as the Electricity Sector Information Sharing and Analysis Center. NERC subsequently contested the audit report's findings and recommendations.

Under the settlement, Enforcement and NERC resolve all outstanding contested recommendations, which related to, among other things, unbudgeted expenditures, the granularity of NERC budget filings, and employee time and expense tracking. The settlement also sets forth a procedure for confirming progress and implementation of audit recommendations. [Settlement] [LaFleur statement]

NERC Names New Chief Operating Officer, Vice President for Reliability Assessment and Performance Analysis

The North American Electric Reliability Corporation (NERC) is pleased to announce that Mark Rossi joined NERC as senior vice president and chief operating officer on January 3, and Tom Burgess joins NERC as vice president and director of Reliability Assessment and Performance Analysis on January 16.

As chief operating officer, Rossi will provide strategic vision, planning, leadership, and oversight of NERC's reliability performance groups, including Standards, Compliance Operations, Reliability Risk Management, Reliability Assessment and Performance Analysis, and Critical Infrastructure.

"Mark brings a unique blend of vision, leadership and consensus-building to NERC that will be a tremendous asset to the electric reliability organization," said Gerry Cauley, president and chief executive officer at NERC. "His industry knowledge will be invaluable in fulfilling our mission of ensuring the reliability of the bulk power system."

Burgess will oversee NERC's Reliability Assessment and Performance Analysis group, which conducts periodic, independent assessments of the reliability and adequacy of the North American bulk power system. In addition, the department identifies and tracks key reliability measurements, conducts analysis of risk trends and works with industry on strategic and tactical approaches to address existing and emerging risks to bulk power system reliability.

"Tom has worked in the energy industry for more than 40 years, participating in many NERC efforts, including serving on the Member Representatives Committee and as a former chair of the NERC Planning Committee. His knowledge of the energy industry, as

well as NERC, brings an experienced leader to one of our most significant efforts," Cauley said. "Tom is a known and trusted adviser to NERC and I look forward to him joining our management team."

Prior to joining NERC, Rossi served as a partner in Accenture's Global Utilities Practice, providing strategic consulting, technology solutions and outsourcing services to Fortune 500 companies. Previously, he was executive vice president at Gestalt, LLC, where he led the company's Energy and Utility practice, and also managed Gestalt's merger with Accenture. During his career, Rossi has led teams that worked on a number of key electric industry issues, including transmission planning and expansion policy, cost allocation, and market design, working with a number of different industry participants and stakeholder processes.

"I am honored to join NERC's talented team and look forward to working with industry stakeholders in our common mission to ensure the reliability of the bulk power system," Rossi said. "The organization is at a key transition point in its history and has identified several strategic initiatives to move towards a risk-based approach to ensuring reliability. I look forward to working with industry to move these efforts ahead so they deliver the potential value they have for improving reliability."

Most recently, Burgess worked at FirstEnergy Corporation, serving as Executive Director, Integrated System Planning and Development. He was responsible for developing strategic plans that maximize value for the transmission and generation business segment, as well as developing integrated planning strategies that optimize transmission and generation. Prior to joining FirstEnergy, he worked for the Ohio Edison Company and the Pennsylvania Power Company, serving in numerous engineering, planning, regulatory and transmission policy positions.

"This is a tremendous opportunity to help lead and shape the future direction of NERC's reliability assessment and performance program," Burgess said. "I am excited about the opportunity to lead such a talented team, both at NERC and across North America."

Reliability Risk Management

NERC Launches New Version of Situation Awareness Tool

The North American Electric Reliability Corporation (NERC) successfully transitioned its situation awareness tool to an updated version in November. The updated software gives industry the ability to monitor and identify in advance conditions that could impact the reliability of the North American bulk power system.

Called Situation Awareness for the FERC, NERC and Regional Entities, Version 2 (SAFNR v2), the tool provides real-time, integrated visibility of generation facilities 500 MW and above, and transmission facilities 200kV and above for Reliability Coordinators, and NERC and FERC situation awareness staff. All 11 U.S. Regional Coordinators are streaming live, operational data on the system.

"This tool gives the electric reliability organization a shared, wide-area view of conditions and emerging reliability events across regions and the interconnections; and the ability help facilitate effective communications among Reliability Coordinators and government agencies," said Mike Moon, senior director for Reliability Risk Management. "Having the ability to monitor conditions as they change on the grid is fundamental to understanding the nature of significant reliability events, and for the continuous improvement of the reliability of the North American bulk power system."

Culminating more than two years of development, SAFNR v2 replaced a tool suite implemented in 2009 that displayed limited data and used individual display formats rather than an integrated view. Additional features expected to be implemented in 2013 include load forecasts and links to more detailed information on current system conditions.

Enhancements made to System Operator Certification and Continuing Ed Database

Efforts to upgrade the System Operator Certification and Continuing Education database (SOCCED) (https://socced.nerc.mcgware.com/Login.aspx) was completed. Phase I enhancements were made to the login page and a new user interface was created for System Operator accounts. Phase II, which will address the provider side of the database, will begin later in the year.

For an instructional video of the upgraded system, copy the following link into your browser: http://www.screencast.com/t/lgztXhziCD3. Send any questions or feedback to NERC.System.Operator.Certification@nerc.net or NERC.Continuing.Education@nerc.net.

Filings

NERC Filings to FERC

(click on the link for full filing)

January 4, 2013

Errata to Petition for Approval of Proposed Reliability Standard EOP-004-2 - Event Reporting

NERC submits an erratum making a minor correction to Exhibit B - Reliability Standard EOP-004-2. *Docket No. RD13-3-000*

January 7, 2013

Comments of NERC in Response to Request for Comments and Notice of Technical Conference on Coordination between Natural Gas and Electricity Markets

NERC submits comments in response to the Federal Energy Regulatory Commission's Notice of Request for Comments and Technical Conference on the Coordination between Natural Gas and Electricity Markets. *Docket No. AD12-12-000*

January 17, 2013

Reply Comments of NERC in Response to Notice of Proposed Rulemaking on Reliability Standards for Geomagnetic Disturbances

NERC submits comments in response to comments submitted in response to the Notice of Proposed Rulemaking on Reliability Standards for Geomagnetic Disturbances. *Docket No. RM12-22-000*

January 22, 2013

Request of NERC for Clarification on Order No. 773 - Revision to ERO Definition of Bulk Electric System and Rules of Procedure

NERC submits a request for clarification on Revisions to the Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure in Order No. 773 issued by FERC on December 20, 2012. *Docket Nos. RM12-6-000 and RM12-7-000*

Comments in Support of WECC's Motion for Designation of Certain Commission Staff as Non-Decisional

NERC submits comments in support of WECC's January 14, 2013 Motion for Designation of Certain Commission Staff as Non-Decisional. *Docket Nos. RD13-1-000 and EL13-1-000*

January 23, 2013

Reply Comments of NERC on Petition for Approval of Reliability Standard VAR-002-2b

NERC submits Reply Comments in response to comments submitted on NERC's Petition for Approval of Proposed Reliability Standard VAR-002-2b concerning the Violation Severity Level for Requirement R2. *Docket No. RD13-2-000*

Quarterly Report of NERC on Status of Development of BAL-003 - Frequency Response and Bias - 4Q2012

NERC submits its 4th Quarter 2012 Quarterly Report of NERC on Status of Development of BAL-003 - Frequency Response and Bias. *Docket Nos. RM06-16-010 and RM06-16-011*

January 31, 2013

Petition of NERC for Approval of CIP Version 5 Reliability Standards

NERC submits a Petition for approval of Critical Infrastructure Protection Reliability Standards Version 5. Docket No. RD13-_-___ Filing Parts: [Petition and Exhibits A-E] [Exhibit F (Part 1 of 2)] [Exhibit F (Part 2of 2)] [Exhibits G-H]

Informational Report on the Analysis of NERC Standards Process Results for Fourth Quarter 2012

NERC submits an informational report on the analysis of NERC Standards Process Results for the Fourth Quarter 2012 in compliance with an order issued by FERC on January 18, 2007 and a subsequent order on September 16, 2010. *Docket Nos. RR06-1-000, RR09-7-000*

NERC Filings in Canada, click here

(click on the link above for full filing)

January 11, 2013

Notice of Filing of NERC of Proposed Reliability Standard EOP-004-2 - Event Reporting

NERC submits a notice of filing of standard EOP-004-2 - Event Reporting. The proposed Reliability Standard provides a comprehensive approach to reporting disturbances and events that have the potential to impact the reliability of the Bulk Electric System in accordance with several Commission directives.

Notice of Filing of NERC 2013-2015 Reliability Standards Development Plan

NERC submits the notice of filing of the Reliability Standards Development Plan: 2013-2015 (RSDP). The RSDP will: 1. Serve as a management tool to guide and coordinate the development of Reliability Standards and provide benchmarks for assessing progress; 2. Serve as a communications tool for coordinating standards development work with applicable governmental agencies in the United States and Canada and for engaging stakeholders in Reliability Standards development activities; and 3. Provide a basis for developing annual plans and budgets for the NERC Reliability Standards program.

Careers at NERC

Meeting Planner Specialist
Location: Atlanta
Details

Bulk Power System Awareness Engineer
Location: Atlanta
Details

Compliance Enforcement Engineer
Location: Washington, DC
Details

ES-ISAC Cybersecurity Specialist
Location: Washington, DC
Details

CIP Security Specialist
Location: Washington, DC
Details

CIP Compliance Auditor
Location: Washington, DC
Details

CIP Compliance Auditor
Location: Atlanta
Details

Senior Web Developer
Location: Atlanta
Details

Attorney
Location: Washington, DC
Details

Engineer of Reliability Risk Controls
Location: Atlanta
Details

Senior Performance and Analysis Engineer
Location: Atlanta
Details

Senior System Analysis and Performance Engineer
Location: Atlanta
Details

Standards Developer
Location: Atlanta
Details

Continuing Education Program Coordinator
Location: Atlanta
Details

Standards

Stakeholders Approve BAL-003-1

Reliability Standard BAL-003-1—Frequency Response and Frequency Bias Setting was approved in a recirculation ballot in December 2012. It will be presented to the NERC Board of Trustees for adoption in February 2013.

The approval of BAL-003-1 is the result of collaboration among NERC's Standards and Reliability Assessment and Performance Analysis staffs and a dedicated team of industry experts (listed in Appendix A in the Frequency Response Initiative Report).

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 in the reliable operation of the bulk electric system. This is particularly true 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 widespread blackouts.

There is evidence of continuing decline in frequency response in the three interconnections in the past 10 years, but no confirmed reason for the decline. The approved standard establishes a minimum frequency response obligation for each Balancing Authority; provides a uniform calculation of frequency response and frequency bias settings that transition to values closer to natural frequency response; and encourages coordinated automatic generation control operation.

Register for Webinar on Generator Relay Loadability

The Project 2010-13.2: Phase 2 of Relay Loadability: Generation standard drafting team is planning an industry webinar at 2 p.m. Eastern February 13. This webinar will focus on draft 2 of PRC-025-1: Generator Relay Loadability, which is posted for a 45-day formal comment period. (For more on the Cost Effective Analysis posted as part of this project, see the following article.) This standard is applicable to each Generator Owner, but due to the drafting team's related Standard Authorization Request (SAR) regarding PRC-023-2: Transmission Relay Loadability, other entities such as Distribution Providers, Transmission Owners, and Planning Authorities also may be interested in the webinar.

The drafting team made noteworthy improvements to the proposed draft 2 of PRC-025-1 based on stakeholder comments, which include clarifications to the standard's Purpose, Applicability, Measures, and Attachment 1: Relay Settings. Additionally, the drafting team divided the Guideline and Technical Basis section into its own document to reduce the number of pages in the standard. Stakeholder comments also revealed a potential overlap between the current PRC-023-2 and proposed PRC-025-1 standards. With the approval of the Standards Committee, the drafting team posted a Standard Authorization Request detailing the need for a modification to PRC-023-2 to create a clear demarcation between the two standards.

All stakeholders interested in attending the webinar may register through the event listing on the NERC calendar.

Piloting the Cost Effective Analysis Process

In October 2012, the Standards Committee approved the Cost Effective Analysis Process for NERC ERO Standards (CEAP), along with an implementation white paper, that authorized existing standard development projects to serve as pilot projects for the process. The CEAP was initially developed in the Northeast Power Coordinating Council-region as an evaluation tool for their regional standards under development. Based on the success of the process in the region, it was presented to the Standards Committee for adoption as an evaluation tool for continent-wide standards.

The process is made up of two phases. The Cost Impact Analysis is conducted during the SAR stage of the standards development and provides an opportunity to identify implementation costs prior to standards development. The second phase is the Cost Effective Analysis and is typically conducted later in the development process, allowing commenters to propose alternative methods to achieve the standards reliability objectives more efficiently. Upon completion of both phases of the CEAP, a report will be developed and posted alongside a standard that is posted for comment and ballot, allowing industry to make a more informed choice about that standard.

In coordination with NERC staff and the Standards Committee, the CEAP development team identified PRC-025-1: Phase 2 of Relay Loadability: Generation as the standard development project to pilot the CEAP. Accordingly, questions related to the CEA phase of the CEAP have been developed and included with the documents posted for PRC-025-1.

Responses to CEAP survey questions will be confidentially aggregated and provided to the standard drafting team for consideration in their

development effort. The draft of PRC-025-1: Phase 2 of Relay Loadability: Generation and the CEAP survey questions are posted through March 11. Comment forms and other information are available on the project page.

Paragraph 81 Recirculation Ballot Results and Next Steps

A recirculation ballot for Project 2013-02: Paragraph 81 concluded on January 17 with 95 percent approval for the 20 standards with 36 requirements proposed for retirement under the project. The Ballot Results page provides a link to the detailed results; more information about the project is available on the project page. The requirements proposed for retirement will be presented to the Board of Trustees and then filed with the appropriate regulatory authorities.

The Paragraph 81 project was initiated in response to paragraph 81 in a March 15, 2012 FERC Order on NERC's Find, Fix and Track process that asked NERC to retire or modify FERC-approved standard requirements that, as FERC noted, "provide little protection to the reliable operations of the BES," are redundant or unnecessary, or whose retirement would increase the efficiency of the ERO's compliance programs.

The standards and requirements that were presented for recirculation ballot met the criteria set forth in the Paragraph 81 Standard Authorization Request and were not believed to require extensive technical research. Along with the identification of these candidates for retirement, the Paragraph 81 team identified standard requirements that need additional technical research before retirement or modification.

Originally, work on these additional requirements was envisioned as a formal second phase of the Paragraph 81 project, but after further consideration, the team determined that it would be more efficient to incorporate consideration of Paragraph 81 criteria into future standards projects instead. As described in the 2013-2015 Reliability Standards Development Plan, all active and future standards projects will include application of the Paragraph 81 concepts. This results in the continuation of the essential Paragraph 81 effort in a way that makes best use of limited industry resources.

Update on Strategic Improvements to Standards Development

A revision of NERC's approach to managing the standards development workload was documented in the *Reliability Standards Development Plan 2013-2015* (Plan), approved by NERC's Board in December 2012. The Plan establishes the goal of transforming the current body of standards to a set of clear, concise results-based standards that ensure the reliability of the bulk power system, while bringing NERC up-to-date on its obligations to address regulatory directives and conduct five-year reviews of standards.

As 2013 begins, NERC continues its efforts to improve its processes in a transparent way by implementing changes to the *Standards Processes Manual* (which was approved by stakeholders in a recirculation ballot that ended on January 28). Further, the Standards Committee approved a new strategic plan and charter to be presented to NERC's Board in February, along with a new chair, Brian Murphy, and vice chair, Scott Miller. Implementation of both the *Standards Processes Manual* and the Standards Committee's guiding documents include an emphasis on smaller, more agile, and better trained drafting teams, along with a focus on informal development and consensus building before a standard is posted for the first time.

As these changes get underway, NERC staff and the Standards Committee Communications and Planning Subcommittee will reach out industry-wide to ensure that the changes and their rationale are clear. If you are interested in hearing from NERC staff or a Standards Committee representative at an upcoming event, contact Mallory Huggins.

Update on Order No. 754 Status

The six-month mark in the 24-month period for Transmission Planners working on the Order No. 754 data request is approaching. Each Transmission Planner in the United States must provide NERC a

status report of the percentage of work completed by March 4. Canadian Transmission Planners who previously acknowledged the data request also are requested to provide a status report to ensure a complete record. Information about submitting this status report is available on the Order No. 754 project page. NERC posted a revision to the Requests for Clarifications and Responses document (January 30).

NERC Transmission Planners submitting information for the data request may register and begin submitting data when the data submittal portal is available. NERC will announce an educational webinar to demonstrate the data entry process soon.

The data request was developed in accordance with the NERC Rules of Procedure, Section 1600 — Request for Data or Information and was approved by the NERC Board on August 16, 2012. Transmission Planners are encouraged to periodically check the project page for information and for appropriate data submittal links. Entities with questions may contact NERC at DataRequest754@nerc.net or contact the project manager, Scott Barfield-McGinnis.

Standards Committee Accepting Nominations for Special Election

Several of the ten industry segments that make up the Standards Committee have vacancies due to resignations, the election of a new chair and vice chair, and a vacancy not filled in the last election. Nominations are being accepted through February 25 in preparation for a special election to fill vacancies in Segment 2 – Regional Transmission Organizations and Independent System Operators; Segment 5 – Electric Generators; Segment 6 – Electricity Brokers, Aggregators, and Marketers; and Segment 8 – Small Electricity End Users.

Anyone may submit a nomination; however, the nominee must be from an entity registered in the particular segment for which the nomination is received. Instructions are provided in the Election of Members of the NERC Standards Committee Procedure and nomination forms are posted on the Standards Committee Election webpage.

More information about the vacancies and a nomination form are available on NERC's website.

Register for NERC's Spring 2013 Standards and Compliance Workshop

Registration is now open for NERC's Spring 2013 Standards and Compliance workshop. The workshop will be March 19-21 at the Hyatt Regency at the Arch in St. Louis. A remote option for stakeholders unable to attend in person will be available. Registration and details are posted on the NERC calendar, and an agenda will be issued soon.

NERC will also host a workshop September 24-26 Atlanta.

Register Now for the Communications in Operations Conference

NERC is hosting a Communications in Operations Conference on February 14-15. The goal is to work toward consensus regarding Reliability Standard COM-003-1: Operating Personnel Communications Protocols, which addresses normal communications, as directed by FERC. Interested stakeholders can find more information, including in-person and webinar registration, in the posted announcement.

Two New Standards Developers Join the Standards Department

In the past month, NERC's Standards two new standards developers to manage or assist with standard development projects:

Jordan Mallory is a standards developer specialist reporting to Val Agnew. Prior to joining the standards group, she was an administrative assistant supporting Compliance Operations, Reliability Risk Management, and the Operating Committee. Prior to joining NERC, Mallory was a senior administrative assistant at MEAG Power. She currently is working on a managerial science and accounting degree from Georgia State University.

Sean Cavote is a standards developer reporting to Laura Hussey. Prior to joining NERC, he was with NiSource in Indianapolis, where he was a senior FERC

attorney. Cavote's prior experience was with Van Ness Feldman in Washington, D.C., as an associate energy attorney, and with United Dynamics in Louisville, Ky., as a power generation consultant. Cavote has a bachelor's degree in political science from the University of Louisville and a juris doctorate from the George Washington University Law School.

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for the following vacant appointment may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination
Seeking an individual from a Canadian entity who has experience in coordination of protection systems (new installations and revisions).

2012 ERO Update

During 2012, NERC actively worked to deliver key results linked to the Corporate Strategic Goals. The following list of electric reliability organization (ERO) activities spotlight two areas: reliability initiatives addressing emerging reliability risks, and activities striving to improve bulk power system reliability. For questions, contact Mike Moon, senior director of Reliability Risk Management.

Quarter 1 – 2012 (January – March)

Compliance Enforcement

- NERC staff spoke at a webinar conducted by the Edison Electric Institute, January 19
- NERC staff spoke at a panel presentation in the National Association of Regulatory Utility Commissioners' winter meeting, February 5
- CEI information update webinar, February
- ERO auditor workshop, February
- NERC staff spoke at a meeting of the Northwest Public Power Association, March 1
- NERC staff spoke at the North American Generator Forum webinar, March 27

Critical Infrastructure

- Cyber Risk Preparedness Assessment Exercise with undisclosed Entity, February 21
- Electricity 101 for Federal Partners. NERC hosted workshop to discuss response, recovery and risk to the BPS, March 21
- National Level Exercise 2012 DHS "tabletop" exercise, ES-ISAC engaged to describe unfolding cyber risk, March 25
- ES-ISAC workshop with the Royal Canadian Mounted Police to discuss threats, vulnerabilities, and risk to BPS, March 27

Reliability Assessment and Performance Analysis

- Transmission System Information Networks (TSIN) move to new website location hosted by NAESB, February
- Technical report released: Loss of Reactive Power, Voltage Instability Most Likely Outcome from GMD, February
- Event Driven Index report approved by NERC's Planning Committee, March

Reliability Risk Management

- Published six Lessons Learned from events on the bulk power system
- Hosted a webinar on the Southwest cold snap recommendations, January 23
- Gave presentation on Southwest cold snap recommendations at Plugging into Natural Gas conference in Portland, Ore., January 25
- Hosted a webinar on the ERO Event Analysis Process Document, March 15
- Hosted a webinar on FAC Alert Recommendations, March 20
- Conducted Improving Human Performance on the Grid conference, March 27-29

Standards

- Hosted Order 754 - Data Request webinar, January 5
- Hosted Order 754 - Data Request - The Study of Single Point of Failure webinar, January 20
- Hosted February 2011 Cold Snap Event Recommendations webinar, January 23

Quarter 2- 2012 (April – June)

Compliance Enforcement

- NERC staff presented during the Energy Bar Association's Compliance and Enforcement Committee and Georgetown University Law Center's Energy Enforcers and Defenders Forum, April 2
- NERC staff presented at the Annual Conference of the National Hydropower Association, April 17
- NERC staff presented at the EEI Reliability Executive Advisory Committee, April 25
- NERC staff presented at the Energy Bar Association's annual meeting, April 26
- NERC staff presented at the NPCC Compliance workshop, May

Compliance Operations

- Hosted the Standards and Compliance Workshop in San Diego, April
- Released the 2011 Annual CMEP report
- Finalized the 2013 Annual Implementation plan.
- Worked with industry to refine risk-based compliance monitoring, including finalizing entity impact evaluation for industry comment, Compliance and Certification Committee working group and Registered Entity focus groups; and integrated consideration of internal controls into standards to move away from zero-tolerance standards.

Critical Infrastructure

- Sufficiency Review Program (SRP)/CIP V4-V5 Outreach Session with Suez to discuss Risk-Based Assessment Methodologies and Critical Assets, May 7
- NERC/NIST/DOE published *Electricity Sub-sector Cyber Security Risk Management Process Guideline*, May 23
- National Level Exercise 2012 DHS exercise, ES-ISAC engaged to describe potential risk (in scenario) to bulk power system, and exercise (draft) NERC Crisis Response Plan June 4
- Critical Infrastructure Protection Committee (CIPC)- brief from DOE highlighting Risk Management and the White House Electricity Sector Cyber Security Capability Maturity Model (ES-C2M2), June 20

Reliability Assessment and Performance Analysis

- NERC, EPRI release open source code to analyze geomagnetically induced currents, April
- NERC participated in FERC technical conference on geomagnetic disturbances, April
    - NERC files Geomagnetic Disturbances Impact to the Bulk Power System with FERC for technical conference
- Web-based Generator Availability Data System to support data collection, April
- Development of new Reliability Risk Controls program, April
- State of Reliability report offers historical reference on bulk power system trends, May
- Web-based spare equipment database collection begins operation, May
- NERC releases two reports focused on high-impact, low-frequency risks: severe impact resiliency and cyber attack, May
- 2012 Summer Reliability Assessment delivered, May
- In conjunction with NERC Standards, hosted two technical conferences on frequency response, May
- Hosted Model Validation workshop, May
- Developed preliminary Reliability Risk Register and initial risk identification, May
- Developed 2012 Pilot Probabilistic Assessment for Long-Term Reliability Assessments, June
- Reviewed prior Reliability Risk Controls program; reevaluated concepts and developed new Reliability Risk Analysis and Control program, June
- Developed internal Reliability Risk Analysis and Control vision document, June
- Revised preliminary Reliability Risk Register, June

Reliability Risk Management

- Published Industry advisory on Preventable EMS and SCADA events, April 10
- Published joint FERC/NERC report on the September 8, 2011 Southwest Blackout Event, May 1
- Published joint FERC/NERC report on the October 29-20, 2011 Northeast Snowstorm, May 31
- Published seven Lessons Learned from events on the Bulk Power System

Standards

- Hosted the Standards and Compliance workshop in San Diego, April
- Hosted draft CIP Standards Version 5 webinar, April 10
- Developed definition of Adequate Level of Reliability, May 23
- Developed draft standards - COM-003-1 and COM-002-3, June 7
- Posted Order No. 754 - Data Request - The Study of Single Point of Failure - Draft 2, June 7
- Revised NERC Standards Processes Manual to Implement SPIG, June 25

Quarter 3- 2012 (July – September)

Compliance Enforcement and Operations

- Hosted Compliance Enforcement Initiative industry webinar, July 11
- ERO Auditor Workshop, September 20
- Industry Workshop, September 21
- NERC Staff presented at 17 Regional Entity Industry Compliance
- Completed two ERO CEA staff training workshops
  - Completed two industry Compliance Seminars
- Completed four lead auditor training (including specialized training for Certification Team Leads)
- Completed two Compliance Investigations process training sessions for NERC and Region staff (February, September 2012)
- Provided a day-long training session of the NERC CI process to first meeting of the newly established Canadian Federal-Provincial-Territorial Electricity Working Group Enforcement Sub-Group staff in Toronto in October 2012
- Earl Shockley and Ken Lotterhos also provided a three hour overview of the ERO Enforcement Process, NERC's evolving approach to compliance, and planned CEI White Paper to Canadian Federal-Provincial-Territorial Electricity Working Group Enforcement Sub-Group staff in October 2012. This briefing was done the day following the Canadian CI training session indicated above.
- Earl Shockley–
  - Represented NERC at the hearings conducted by the California State legislature review of the September 8, 2011 Southwest Blackout
  - Represented NERC at the Cold Snap panels conducted by FERC in October 2012 in Texas and New Mexico
- Completed the 2013 CMEP Implementation Plan
- All Registration Letter templates posted on NERC website
- Certification Letter templates covering the entire Certification Process submitted to ORCS and Regions for review and comments. This promotes both consistency and transparency
- Formalized the Certification Review process for certified entities that have reviewable changes to their operational or structural characteristics.
- Compliance Analysis Reports (CARs)
  - Compliance Analysis Report: CIP-005
- Compliance Application Notices (CANs)
  - CAN-0008: PRC-005 R2: Basis for First Maintenance and Testing Date (Revised)
  - CAN-0011: PRC-005 R2: Interval Start Date for New Equipment (Revised)
  - CAN-0012: Completion of Periodic Activity Requirements During Implementation Plan (Revised)

- CAN-0043: PRC-005: Protection System Maintenance and Testing Evidence (Revised)

Critical Infrastructure

- Completed three Sufficiency Review Program (SRP)/CIP V4-V5 Outreach Sessions (July 18, August 28, September 11); four total SRPs completed; six additional SRPs scheduled
- Conducted Aurora briefings as part of the SRPs; completed bi-annual Aurora update report and submitted to FERC, August 14
- Conducted a Cyber Risk Preparedness Assessment, June 29
- Began piloting threat indicators search tool for ES-ISAC analytics and a new system for tracking incident reports submitted to the ES-ISAC
- Contributed to technical aspects of CIP Standards in preparation for posting and ballot; meetings on July 10, August 14, and other calls
- Finalized draft of Crisis Action Plan with other NERC department representatives
- Grid Security Conference 2012: over 220 registered attendees by September 30; 28 speakers invited and confirmed; three training sessions scheduled
- Reviewed the Department of Energy Cybersecurity for Energy Delivery Systems programs and projects for relevancy and applicability to the Electricity Sub-sector, July 24
- Participated in CCWG Meeting, August 9
- Hosted ERO Auditor workshop and CIP Auditor Breakout Workshop in Atlanta, September 18-20
- Developed Cyber Vulnerability Assessment presentation with Encari for CIPC and posted to NERC site
- Spoke to an EPRI/Generator Forum conference on CIP Standards, July 11
- CIP Compliance and Monitoring:
  - Participated on six CIP Compliance Audits and provided compliance guidance to regions
    - East Kentucky Power Cooperative (SERC), Lexington, KY: July 16-August 3
    - Grand River Dam Authority (SPP RE), Locust Grove, OK: August 27-30; October 1-12
    - First Energy (RFC), Fairmont, WV: September 24-28
  - Presented CIP FFT Guidance to Regions at ENSWG
  - Presented V3-V4 Transition Plan to CCWG and worked closely with industry to address "bright-line" transition issues
  - Presented Internal Controls Framework at ERO Compliance Auditor Training, September 18-20
  - Presented at SERC's CIP Compliance Workshop
  - Presented at RFC's Compliance Workshop
  - Worked with the Regions' Technical Feasibility Exception (TFE) Managers to prepare the TFE annual report that was filed with FERC on September 28
  - Led the TFE Managers' meeting in Atlanta, September 20
  - Worked with the Regions and NERC Legal to develop proposed revisions that streamline the Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards (Appendix 4D to NERC's Rules of Procedure)
  - Participated in the quarterly CCWG meeting at NPCC in New York, August 8-9
  - Attended ASIS/ISC(2) security conference in Philadelphia, September 10-13
- Critical Infrastructure Protection Committee (CIPC):
  - Conducted a CIPC Workshops for industry education/training, September 18
  - Supported the Compliance Ops and CANS initiatives through the Compliance and Enforcement Input WG

- Completed a CIPC review with HITF on of the Coordinated Action Plan to assign tasks for addressing High Impact Low Frequency Events, September 18

Reliability Assessment and Performance Analysis

- Assessment of Extended Los of Space-Based Positioning, Navigation and Timing
  - ESCC Review: July 17, 2012
  - http://www.nerc.com/docs/escc/Assessment%20of%20the%20extended%20loss%20of%20space-based%20positioning,%20navigation%20and%20timing.pdf
- IVGTF Task 1-3: *Interconnection Requirements for Variable Generation*
  - PC Approval, September 2012
  - Website Release, September 28, 2012
- RISC Charter approved by the Board of Trustees, August 2012
- FERC Order 754 Data Request for the Interpretation of NERC Standard TPL-002-0a for PacifiCorp
  - Released to Industry on schedule, September 1, 2012
  - Link: https://www.nerc.net/Order754/Default.aspx
- Disseminated Governor Survey data to regions for comparison with power flow and dynamics model
- Collaborative effort with North American Transmission Forum (NATF) on instructional materials for transmission owners (TOs) and generator owners (GOs) on generator dynamics modeling.

Reliability Risk Management / Training

- Hosted Facility Ratings Alert Recommendation Webinar, October 3, 2012
- Published Alerts:
  - Alert A-2012-09-12-01 (Shamoon) was published on September 12
  - Alert A-2012-10-04-01 (Telvent network intrusion) was published on October 4
  - NERC's Communication Update: New 24-Hour Emergency Hotline Phone/Email Contact Update and Compliant Hotline Information
- Presentation of Best Practices from the Texas Cold Snap Event from EAS to OC, September 18, 2012
- WECC Trainers Workshop in San Diego, July 25
- Cause Analysis Course Atlanta, GA, July 31
- Published NERC Cause Coding Assignment Process , July 31
- Cause Analysis and Data Workshop Atlanta, GA, August 1-2
- MISO's Emergency Operating Plan Coordination Workshop in Minneapolis/St. Paul, August 7
- NPCC Cause Analysis Course in New York City, NY, August 9
- ATC Cause Analysis Course and HP Update in Milwaukee, WI, August 13-14
- MISO's Emergency Operating Plan Coordination Workshop in Carmel, IN, August 15
- EPRI Power Switching Safety & Reliability Conference in Seattle, Washington, August 27-28
- Cause Analysis Course MRO in Minneapolis/St. Paul, September, 12-14
- OC/PC/CIPC in St. Louis, September 17-19
- EA supported RAPA with the 2012-13 Winter Reliability Assessment Data Request
- Posted four Lesson Learned from the Southwest cold snap on, September 12

Quarter 4- 2012 (October – December)

Compliance Enforcement and Operations

- Standards and Compliance Workshop, October 24-25
- CEI Training for Investigators, November 7
- Quarterly Update on Enforcement Statistics to Compliance and Certification Committee, December 6
- Filed three Notices of Penalty on sets of violations representing serious risks to BPS reliability

- Provided an all day training session of the NERC Compliance Investigation (CI) process at the first meeting of the Canadian Federal-Provincial-Territorial Electricity Working Group Enforcement Sub-Group staff in Toronto
- Earl Shockley and Ken Lotterhos also provided a three hour overview of the ERO Enforcement Process, NERC's evolving approach to compliance, and planned RAI White Paper to Canadian Federal-Provincial-Territorial Electricity Working Group Enforcement Sub-Group
- Completed the Standards and Compliance workshop for the industry in Atlanta
- NERC Staff presented at seven (7) Regional Entity Industry Compliance Workshops
- Completed one lead auditor training (including specialized training for Certification Team Leads and Crucial Conversation)
- Represented NERC at the Cold Snap panels conducted by FERC in October 2012 in Texas and New Mexico
- Completed and posted the revised 2013 CMEP Implementation Plan for the ERO Enterprise [LINK]
- All Registration Letter templates completed and in use
- Certification Letter templates covering the entire Certification Process submitted to ORCS and Regions for review and comments. This promotes both consistency and transparency
- Formalized the Certification Review process for certified entities that have reviewable changes to their operational or structural characteristics
- Compliance Application Notices (CANs)
  - CAN-0008: PRC-005 R2: Basis for First Maintenance and Testing Date (Revised)
  - CAN-0011: PRC-005 R2: Interval Start Date for New Equipment (Revised)
  - CAN-0012: Completion of Periodic Activity Requirements During Implementation Plan (Revised)
  - CAN-0043: PRC-005: Protection System Maintenance and Testing Evidence (Revised)
- Report completed on the Reliability Risk Outcomes – Corporate Goal #9
- Executive summary report completed on the Reliability Standard Advisory Service (RSA) and its process report – Corporate Goal #10
- Posted the three (3) ERO Case Studies in one report [LINK] – Corporate Goal #11A
- Completed two (2) RE audit oversight engagements in the fourth quarter
- Develop Risk based compliance monitoring approaches. Reliability Assurance Initiative (RAI) whitepaper drafts have been posted for industry comments [LINK] – Corporate Goal #12
- ERO CEA staff training completed for 100% of the RE auditors and investigators [LINK]. Training materials posted [LINK] – Corporate Goal #26B

Critical Infrastructure

- Hosted a webinar focused on Distributed Denial of Service, October 12
- Hosted NERC's 2nd Annual Grid Security Conference, San Diego, October 16-18
- Sufficiency Review of Registered Entity, October 23-25
- Coordinated Hurricane Sandy response efforts with other sectors, Washington, DC, October 28-November 10
- Presented at the Utility Services Conference, Shrewsbury, MA, November 8
- Sufficiency Review of Registered Entity, November 13-14
- Canadian Classified Brief, Ottawa Canada, November 29
- Participated in the Resilient Constellation Exercise Series National Stakeholder Seminar and Workshop, Washington, DC, December 7
- Hosted the Critical Infrastructure Protection Committee meeting, Atlanta, December 11-13
- Participated in the National Association of Regulatory Utility Commissioners Catastrophic

Response Executive Table Top, New York, NY, December 13
- Finalized the Crisis Action Plan (CAP); facilitated CAP Executive Table Top and Overview, Washington, DC, and Atlanta, GA, December 20
- Conducted CRPA/C2M2 integrated activity, including one CRPA in fourth quarter and support for C2M2 development effort

Reliability Assessment and Performance Analysis
- Issued the Frequency Responsive Initiative Report
- Obtained PC and BOT support for TADs data gathering improvements
- Held the First Reliability Issues Information Conference to support input to the RISC on November 28, 2012 in Washington, D.C.
- Issued the 2012-13 Winter Assessment
- Issued the LTRA

Standards
- Hosted Transmission Planning Standards: Footnote "b", October 18
- Hosted Definition of Bulk Electric System: Bulk Electric System Guidance Document, October 18
- Hosted Project 2009-01 Disturbance Sabotage and Reporting, October 22
- Hosted NERC Standards and Compliance Workshop in Atlanta, October 23-25
- Hosted Project 2007-02 Draft Standard COM-003-1 Industry Webinar, November 27
- Hosted NERC Standard Processes Manual Revisions to Implement SPIG Recommendations Industry Webinar, December 6
- Hosted Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-025-1 Generator Relay Loadability, December 13

Reliability Risk Management / Training
- Cause Analysis Training at four Regions (WECC, TRE, SPP and SERC) 155 people attending the training
- 255 events available, 246 reports are closed and 202 were cause coded

Subject matter expert confirmed EMS information issues from April Alert confirmed to be correct

From: NERC Standards Announcements (Do Not Reply)
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - December 3-9, 2012
Date: Monday, December 03, 2012 8:53:01 AM

Standards Bulletin

December 3-9, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- Interpretation 2012-INT-02: Interpretation of TPL-003-0a and TPL-004-0 for SPCS – Open November 26 – December 5, 2012 (Initial Ballot)
- Project 2013-02: Paragraph 81 – Open November 30 – December 10, 2012 (Initial Ballot)
- Project 2007-02: Operating Personnel Communications Protocols (COM-003) – Open December 4-13, 2012 (Successive Ballot)
- Project 2007-06: System Protection Coordination (PRC-001 and PRC-027) – Open December 7-17, 2012 (Successive Ballot)

Posted for Comment (comment periods close at 8 p.m. Eastern)

- Interpretation 2012-INT-02: Interpretation of TPL-003-0a and TPL-004-0 for SPCS – Open October 22 – December 5, 2012 (Comment Form)
- Interpretation 2012-INT-04: Interpretation of CIP-007 for ITC – Open November 9 – December 10, 2012 (Comment Form)
- Interpretation 2012-INT-06: Interpretation of CIP-003 for Consumers Energy – Open November 9 – December 10, 2012 (Comment Form)
- Project 2013-02: Paragraph 81 – Open October 25 – December 10, 2012 (Comment Form)
- Project 2007-02: Operating Personnel Communications Protocols (COM-003) – Open November 14 – December 13, 2012 (Comment Form)
- Project 2007-06: System Protection Coordination (PRC-001 and PRC-027) – Open November 16 –December 17, 2012 (Comment Form)
- Interpretation 2012-INT-05: Interpretation of CIP-002-3 for OGE – Open November 6 – December 20, 2012 (Comment Form)
- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open November 21 – December 20, 2012 (Comment Form)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 14, 2013 (Comment Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Interpretation 2012-INT-05: Interpretation of CIP-002-3 for OGE – Open November 6 – December 5, 2012 (Join Ballot Pool)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 14, 2013 (Join Ballot Pool)

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- Interpretation 2012-INT-05: Interpretation of CIP-002-3 for OGE – Open December 11-20,

2012 (Initial Ballot)

- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open December 11-20, 2012 (Successive Ballot)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open January 4-14, 2013 (Initial Ballot and Non-binding Poll)

Standard Drafting Team Vacancies and Nominations

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

Upcoming Standards (and Standards-Related) Webinars

- Standard Processes Manual Revisions to Implement SPIG Recommendations Industry Webinar – 11 a.m.-12 p.m. Eastern on December 6, 2012 (Register)
- Winter Preparation for Severe Cold Weather Industry Webinar – 2:30-4 p.m. on December 10, 2012 (Register)
- Project 2010-13.2: Phase 2 of Relay Loadability: Generation (PRC-025) Industry Webinar –2-4 p.m. Eastern on December 13, 2012 (Register)

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Bulletin: December 10-16, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2013-02: Paragraph 81 – Open November 30 – December 10, 2012 (Initial Ballot)
- Project 2007-02: Operating Personnel Communications Protocols (COM-003) – Open December 4-13, 2012 (Successive Ballot)
- Project 2007-06: System Protection Coordination (PRC-001 and PRC-027) – Open December 7-17, 2012 (Successive Ballot)
- Interpretation 2012-INT-05: Interpretation of CIP-002-3 for OGE – Open December 11-20, 2012 (Initial Ballot)
- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open December 11-20, 2012 (Successive Ballot)

Posted for Comment (comment periods close at 8 p.m. Eastern)

- Interpretation 2012-INT-04: Interpretation of CIP-007 for ITC – Open November 9 – December 10, 2012 (Comment Form)
- Interpretation 2012-INT-06: Interpretation of CIP-003 for Consumers Energy – Open November 9 – December 10, 2012 (Comment Form)
- Project 2013-02: Paragraph 81 – Open October 25 – December 10, 2012 (Comment Form)
- Project 2007-02: Operating Personnel Communications Protocols (COM-003) – Open November 14 – December 13, 2012 (Comment Form)
- Project 2007-06: System Protection Coordination (PRC-001 and PRC-027) – Open November 16 – December 17, 2012 (Comment Form)
- Interpretation 2012-INT-05: Interpretation of CIP-002-3 for OGE – Open November 6 – December 20, 2012 (Comment Form)
- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open November 21 – December 20, 2012 (Comment Form)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 14, 2013 (Comment Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 3, 2013 (Join Ballot Pool)

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open January 4-14, 2013 (Initial Ballot and Non-binding Poll)

BOT Adoptions and NERC Website Updates

On November 26, 2012, the NERC Board of Trustees adopted Reliability Standards CIP-002-5 - Cyber Security — BES Cyber System Categorization, CIP-003-5 - Cyber Security — Security Management Controls, CIP-004-5 - Cyber Security — Personnel & Training, CIP-005-5 - Cyber Security — Electronic Security Perimeter(s), CIP-006-5 - Cyber Security — Physical Security of BES Cyber Systems, CIP-007-5 - Cyber Security — System Security Management, CIP-008-5 - Cyber Security — Incident Reporting and Response Planning, CIP-009-5 - Cyber Security — Recovery Plans for BES, CIP-010-1 - Cyber Security — Configuration Change Management and Vulnerability Assessments and CIP-011-1 - Cyber Security — Information Protection.

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF Matrix on NERC's website have been updated accordingly.

Standard Drafting Team Vacancies and Nominations

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

Upcoming Standards (and Standards-Related) Webinars

- Winter Preparation for Severe Cold Weather Industry Webinar – December 10, 2012 from 2:30-4:00 p.m. (Register)
- Project 2010-13.2: Phase 2 of Relay Loadability: Generation (PRC-025) Industry Webinar – December 13, 2012 from 2:00-4:00 p.m. Eastern (Register)

Geomagnetic Disturbance Resource Page Made Available

NERC has created a Geomagnetic Disturbance Resource page to compile resources for stakeholders preparing comments on FERC's October 18, 2012 Notice of Proposed Rulemaking on Reliability Standards for Geomagnetic Disturbances (Docket No. RM12-22-000). The page can be found on the Standards Under Development page under "Projects Under Consideration for Development."

From: NERC Standards Announcements (Do Not Reply)
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - December 17-23, 2012
Date: Monday, December 17, 2012 9:08:57 AM

Standards Bulletin

December 17-23, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2007-06: System Protection Coordination (PRC-001 and PRC-027) – Open December 7-17, 2012 (Successive Ballot)

- Interpretation 2012-INT-05: Interpretation of CIP-002-3 for OGE – Open December 11-20, 2012 (Initial Ballot)

- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open December 11-20, 2012 (Successive Ballot)

- Project 2007-09: Generator Verification (MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-1) – Open December 12-21, 2012 (Recirculation Ballot)

- Project 2007-12: Frequency Response (BAL-003-1) – Open December 12-21, 2012 (Recirculation Ballot)

Posted for Comment (comment periods close at 8 p.m. Eastern)

- Project 2007-06: System Protection Coordination (PRC-001 and PRC-027) – Open November 16 –December 17, 2012 (Comment Form)
- Interpretation 2012-INT-05: Interpretation of CIP-002-3 for OGE – Open November 6 – December 20, 2012 (Comment Form)
- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open November 21 – December 20, 2012 (Comment Form)
- Project 2007-09: Generator Verification (PRC-024-1) – Open December 12, 2013 – January 11, 2013 (Comment Form)
- Project 2010-11: TPL Table 1, Footnote 'b' – Open December 10, 2012 – January 11, 2013 (Comment Form)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 14, 2013 (Comment Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 3, 2013 (Join Ballot Pool)

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2007-09: Generator Verification (PRC-024-1) – Open January 2-11, 2013 (Successive Ballot and Non-binding Poll)
- Project 2010-11: TPL Table 1, Footnote 'b' – Open January 2-11, 2013 (Successive Ballot)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open January 4-14, 2013 (Initial Ballot and Non-binding Poll)

Final Revisions to Outstanding VRFs and VSLs Posted

Final revisions (or additional justification) and a consideration of comments form for a set of outstanding VRFs and VSLs have been posted to the project page. If adopted by the Board of Trustees on December 19, the revisions will be filed with applicable regulatory authorities by February 2013

FERC Approvals and NERC Website Updates

On December 12, 2012, FERC issued a letter order approving the interpretation of CIP-004. As a result of this approval, the interpretation was appended to CIP-004-3a: Cyber Security – Personnel Training, which is currently enforceable, along with CIP-004-4a- Cyber Security – Personnel Training, which will be enforceable on April 1, 2014.

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF and VSL Matrices on NERC's website have been updated accordingly.

Standard Drafting Team Vacancies and Nominations

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

Upcoming Standards Webinars

- Project 2010-11: TPL Table 1 Order, Footnote 'b' Industry Webinar – January 8, 2013 from 1:00-3:00 p.m. Eastern (Register)

OTHER ITEMS

Reliability Assurance Initiative: Concept White Paper Posted for Industry Comment

The Reliability Assurance Initiative is for identifying (and implementing where appropriate) changes that enhance the effectiveness of the Electric Reliability Organization (ERO) compliance and enforcement program to avoid cascading events and the resulting major loss of load. Activities include drafting six conceptual white papers that describe the desired end state and change state elements necessary to achieve the attributes of compliance of a mature ERO. The white papers and the corresponding input and feedback to these papers will be included in a formal filing to FERC targeted for March 2013.

To date, three white papers have been posted to the Reliability Assurance Initiative web page for industry comment and feedback. It is recommended that all Regional Entities and registered entities check the NERC website regularly to ensure the latest version of each paper is being used.

Entity comments and responses to posted questions should be submitted to: RAIcomments@nerc.net.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Standards Bulletin

December 24-30, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

STANDARDS ITEMS

Posted for Comment (comment periods close at 8 p.m. Eastern)

- Project 2007-09: Generator Verification (PRC-024-1) – Open December 12, 2013 – January 11, 2013 (Comment Form)
- Project 2010-11: TPL Table 1, Footnote 'b' – Open December 10, 2012 – January 11, 2013 (Comment Form)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 14, 2013 (Comment Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 3, 2013 (Join Ballot Pool)

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2007-09: Generator Verification (PRC-024-1) – Open January 2-11, 2013 (Successive Ballot and Non-binding Poll)
- Project 2010-11: TPL Table 1, Footnote 'b' – Open January 2-11, 2013 (Successive Ballot)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open January 4-14, 2013 (Initial Ballot and Non-binding Poll)

NERC Board of Trustees Adoptions and NERC Website Updates

On December 19, 2012, the NERC Board of Trustees adopted the following Standards: BAL-001-1: Real Power Balancing Control Performance (a WECC Regional variance of BAL-001-0.1a), and BAL-004-WECC-02: Automatic Time Error Control. The Board also adopted proposed revisions to outstanding VRFs and VSLs and the 2013-2015 Reliability Standards Development Plan (RSDP).

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF Matrix on NERC's website have been updated accordingly.

Standards Drafting Team Vacancies and Nominations

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

Upcoming Standards Webinars

- Project 2010-11: TPL Table 1 Order, Footnote 'b' Industry Webinar – January 8, 2013 from 1:00-3:00 p.m. Eastern (Register)

OTHER ITEMS

Reliability Assurance Initiative Concept White Papers Posed for Industry Comment

The Reliability Assurance Initiative is for identifying (and implementing where appropriate) changes that enhance the effectiveness of the Electric Reliability Organization (ERO) compliance and enforcement program to avoid cascading events and the resulting major loss of load. Activities include drafting six conceptual white papers that describe the desired end state and change state elements necessary to achieve the attributes of compliance of a mature ERO. The white papers and the corresponding input and feedback to these papers will be included in a formal filing to FERC targeted for March 2013.

To date, three white papers have been posted to the Reliability Assurance Initiative web page for industry comment and feedback. It is recommended that all Regional Entities and registered entities check the NERC website regularly to ensure the latest version of each paper is being used. Entity comments and responses to posted questions should be submitted to: RAIcomments@nerc.net.

Draft Reliability Guideline Posted for Industry Comment

The North American Electric Reliability Corporation Operating Committee is seeking industry comments on the Draft Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices. Entity comments should be submitted on the posted comment form by February 4, 2013 to reliabilityguidelinecomments@nerc.net.

From: NERC Standards Announcements (Do Not Reply)
To: Wendy Muller
Subject: NERC Standards Bulletin: December 31, 2012 - January 6, 2013
Date: Monday, December 31, 2012 7:08:33 AM

Standards Bulletin

December 31, 2012 – January 6, 2013

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent Board of Trustees adoptions, FERC approvals, and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2007-09: Generator Verification (PRC-024-1) – Open January 2-11, 2013 (Successive Ballot and Non-binding Poll)
- Project 2010-11: TPL Table 1, Footnote 'b' – Open January 2-11, 2013 (Successive Ballot)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open January 4-14, 2013 (Initial Ballot and Non-binding Poll)

Posted for Comment (comment periods close at 8 p.m. Eastern)

- Project 2007-09: Generator Verification (PRC-024-1) – Open December 12, 2013 – January 11, 2013 (Comment Form)
- Project 2010-11: TPL Table 1, Footnote 'b' – Open December 10, 2012 – January 11, 2013 (Comment Form)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 14, 2013 (Comment Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 3, 2013 (Join Ballot Pool)

Standards Drafting Team Vacancies and Nominations

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self-nomination form to sarcomm@nerc.com.

Upcoming Standards Webinars

- Project 2010-11: TPL Table 1 Order, Footnote 'b' Industry Webinar – January 8, 2013 from 1:00-3:00 p.m. Eastern (Register)

OTHER ITEMS

Reliability Assurance Initiative Concept White Papers Posed for Industry Comment

The Reliability Assurance Initiative is for identifying (and implementing where appropriate) changes that enhance the effectiveness of the Electric Reliability Organization (ERO) compliance and enforcement program to avoid cascading events and the resulting major loss of load. Activities include drafting six conceptual white papers that describe the desired end state and change state elements necessary to achieve the attributes of compliance of a mature ERO. The white papers and the corresponding input and feedback to these papers will be included in a formal filing to FERC targeted for March 2013.

To date, three white papers have been posted to the Reliability Assurance Initiative web page for industry comment and feedback. It is recommended that all Regional Entities and registered entities check the NERC website regularly to ensure the latest version of each paper is being used. Entity comments and responses to posted questions should be submitted to: RAIcomments@nerc.net.

Draft Reliability Guideline Posted for Industry Comment

The North American Electric Reliability Corporation Operating Committee is seeking industry comments on the Draft Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices. Entity comments should be submitted on the posted comment form by February 4, 2013 to reliabilityguidelinecomments@nerc.net.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Standards Bulletin

January 7-13, 2013

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent Board of Trustees adoptions, FERC approvals, and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin.

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STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2007-09: Generator Verification (PRC-024-1) – Open January 2-11, 2013 (Successive Ballot and Non-binding Poll)
- Project 2010-11: TPL Table 1, Footnote 'b' – Open January 2-11, 2013 (Successive Ballot)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open January 4-14, 2013 (Initial Ballot and Non-binding Poll)

Posted for Comment (comment periods close at 8 p.m. Eastern)

- Project 2007-09: Generator Verification (PRC-024-1) – Open December 12, 2013 – January 11, 2013 (Comment Form)
- Project 2010-11: TPL Table 1, Footnote 'b' – Open December 10, 2012 – January 11, 2013 (Comment Form)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 14, 2013 (Comment Form)

Standards Drafting Team Vacancies and Nominations

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

Upcoming Standards Webinars

- Project 2010-11: TPL Table 1 Order, Footnote 'b' Industry Webinar – January 8, 2013 from 1:00-3:00 p.m. Eastern (Register)

Save the Dates for NERC's Standards and Compliance Workshops

- March 19-21, 2013 in St. Louis
- September 24-26, 2013 in Atlanta

OTHER ITEMS

Reliability Assurance Initiative Concept White Papers Posed for Industry Comment

The Reliability Assurance Initiative is for identifying (and implementing where appropriate) changes that enhance the effectiveness of the Electric Reliability Organization (ERO) compliance and enforcement program to avoid cascading events and the resulting major loss of load. Activities include drafting six conceptual white papers that describe the desired end state and change state elements necessary to achieve the attributes of compliance of a mature ERO. The white papers and the corresponding input and feedback to these papers will be included in a formal filing to FERC targeted for March 2013.

To date, three white papers have been posted to the Reliability Assurance Initiative web page for industry comment and feedback. It is recommended that all Regional Entities and registered entities check the NERC website regularly to ensure the latest version of each paper is being used. Entity comments and responses to posted questions should be submitted to: RAIcomments@nerc.net.

Draft Reliability Guideline Posted for Industry Comment

The North American Electric Reliability Corporation Operating Committee is seeking industry comments on the Draft Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices. Entity comments should be submitted on the posted comment form by February 4, 2013 to reliabilityguidelinecomments@nerc.net.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Bulletin

January 14-20, 2013

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent Board of Trustees adoptions, FERC approvals, and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin. The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

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STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open January 4-14, 2013 (Initial Ballot and Non-binding Poll)
- Project 2013-02: Paragraph 81 – Open January 8-17, 2013 (Recirculation Ballot)

Posted for Comment (comment periods close at 8 p.m. Eastern)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-012-1) – Open November 30, 2012 – January 14, 2013 (Comment Form)

FERC Approvals and NERC Website Updates

On December 20, 2012, FERC issued an Order approving PRC-006-SERC-01- Automatic Underfrequency Load Shedding Requirements, an Order approving PRC-006-SERC-01- Automatic Underfrequency Load Shedding Requirements, and an Order approving revisions to the Bulk Electric System definition (now incorporated into NERC's Glossary of Terms). The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF and VSL Matrices on NERC's website have been updated accordingly.

Standards Drafting Team Vacancies and Nominations

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

Save the Dates for NERC's Standards and Compliance Workshops

- March 19-21, 2013 in St. Louis
- September 24-26, 2013 in Atlanta

OTHER ITEMS

Reliability Assurance Initiative Concept White Papers Posed for Industry Comment

The Reliability Assurance Initiative is for identifying (and implementing where appropriate) changes that enhance the effectiveness of the Electric Reliability Organization (ERO) compliance and enforcement program to avoid cascading events and the resulting major loss of load. Activities include drafting six conceptual white papers that describe the desired end state and change state elements necessary to achieve the attributes of compliance of a mature ERO. The white papers and the corresponding input and feedback to these papers will be included in a formal filing to FERC targeted for March 2013.

To date, three white papers have been posted to the Reliability Assurance Initiative web page for industry comment and feedback. It is recommended that all Regional Entities and registered entities check the NERC website regularly to ensure the latest version of each paper is being used. Entity comments and responses to posted questions should be submitted to: RAIcomments@nerc.net.

Draft Reliability Guideline Posted for Industry Comment

The North American Electric Reliability Corporation Operating Committee is seeking industry comments on the Draft Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices. Entity comments should be submitted on the posted comment form by February 4, 2013 to reliabilityguidelinecomments@nerc.net.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Bulletin

January 22-27, 2013

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent Board of Trustees adoptions, FERC approvals, and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin. The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- Interpretation 2012-INT-05: Interpretation of CIP-002-3 for OGE – Open January 14-23, 2013 (Recirculation Ballot)
- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open January 18-28, 2013 (Recirculation Ballot)
- Project 2010-11: TPL Table 1 Order (TPL-002-2b, footnote 'b' and TPL-001-3, footnote 12) – Open January 22-31, 2013 (Recirculation Ballot)
  - This recirculation ballot includes a substantive change to TPL-002-2b (formerly referred to as TPL-002-1c), footnote b and TPL-001-3 (formerly referred to as TPL-001-2a), footnote 12 to address applicability to registered entities in Canada and Mexico. The change adds text to the footnotes and Attachment 1 that addresses jurisdictional differences – specifically, that the 75 MW limit on planned, non-consequential load loss included in the footnotes and Attachment would not apply to Canadian or Mexican registered entities. The inclusion of this substantive change during a recirculation ballot was approved by the Standards Committee as a deviation from the Standard Processes Manual to provide NERC with an opportunity to meet a February 2013 deadline from the Federal Energy Regulatory Commission.
  - Please also note that NERC has identified that the drafting team was given incorrect guidance on the proper numbering of the standards to account for the revision to be consistent with the NERC Standards Numbering Convention. The standards versions have been updated to reflect the appropriate numbering convention and are now identified as TPL-002-2b and TPL-001-3.
- Interpretation 2012-INT-02: TPL-003-0a and TPL-004-0 for SPCS – Open January 22-31, 2013 (Recirculation Ballot)

Posted for Comment (comment periods close at 8 p.m. ET)

- Project 2010-05.1: Protection Systems: Phase 1 Misoperations (PRC-004-3) – Open January 22-February 20, 2013 (Comment Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. ET)

- None

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2010-05.1: Protection Systems: Phase 1 Misoperations (PRC-004-3) – Open February 11-20, 2013 (Successive Ballot)

Standards Drafting Team Vacancies and Nominations

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

Upcoming Events

- Communications in Operations Conference, Atlanta, GA – February 14-15, 2013 (Register)
- Save the Dates for NERC's 2013 Standards and Compliance Workshops
  - March 19-21, 2013 in St. Louis
  - September 24-26, 2013 in Atlanta

OTHER ITEMS

Reliability Assurance Initiative Concept White Papers Posed for Industry Comment

The Reliability Assurance Initiative is for identifying (and implementing where appropriate) changes that enhance the effectiveness of the Electric Reliability Organization (ERO) compliance and enforcement program to avoid cascading events and the resulting major loss of load. Activities include drafting five conceptual white papers ("The Need for Change" and four key change state element papers) that describe the desired end state and change state elements necessary to achieve the attributes of compliance of a mature ERO.

To date, three white papers have been posted to the Reliability Assurance Initiative web page for industry comment and feedback. It is recommended that all Regional Entities and registered entities check the NERC website regularly to ensure the latest version of each paper is being used. Entity comments and responses to posted questions should be submitted to: RAIcomments@nerc.net.

Draft Reliability Guideline Posted for Industry Comment

The North American Electric Reliability Corporation Operating Committee is seeking industry comments on the Draft Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry

Practices. Entity comments should be submitted on the posted comment form by February 4, 2013 to reliabilityguidelinecomments@nerc.net.

Upcoming Events

- Reliability Standard Advisory Service: PER-005-1 Lessons Learned – March 6, 2013, 1-2 p.m. Eastern (Register)
  - The NERC Reliability Standard Advisory Service (RSA) program is designed to detect and highlight industry difficulties with new reliability standards, and to develop and improve internal compliance approaches prior to each reliability standard's mandatory enforcement date. PER-005-1 was selected as the reliability standard in the initial RSA based on the requirement and unique characteristics of using a systematic approach to establish a training program.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Bulletin

January 28 – February 3, 2013

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent Board of Trustees adoptions, FERC approvals, and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin. The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

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STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open January 18-28, 2013 (Recirculation Ballot)
- Project 2010-11: TPL Table 1 Order (TPL-002-2b, footnote 'b' and TPL-001-3, footnote 12) – Open January 22-31, 2013 (Recirculation Ballot)
- Interpretation 2012-INT-02: TPL-003-0a and TPL-004-0 for SPCS – Open January 22-31, 2013 (Recirculation Ballot)

Posted for Comment (comment periods close at 8 p.m. Eastern)

- Project 2010-05.1: Protection Systems: Phase 1 Misoperations (PRC-004-3) – Open January 22-February 20, 2013 (Comment Form)
- Project 2007-09: Generator Verification (PRC-024-1) – January 25-Feburary 25, 2013 (Comment Form)
- Project 2010-13.2: Phase 2 of Relay Loadability: Generation – Open March 1-11, 2013
  - PRC-025-1 (Comment Form)
  - Cost Effective Analysis (Comment Form; see CEAP web page for background)
  - Supplemental SAR (Comment Form)
  - RSAW (Draft RSAW and Feedback Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Project 2010-13.2: Phase 2 of Relay Loadability: Generation – Open January 25-February 25, 2013 (Ballot Pool)

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2010-05.1: Protection Systems: Phase 1 Misoperations (PRC-004-3) – Open February 11-20, 2013 (Successive Ballot)
- Project 2007-09: Generator Verification (PRC-024-1) – Open February 15-35, 2013 (Successive Ballot)
- Project 2010-13.2: Phase 2 of Relay Loadability: Generation – Open March 1-11, 2013 (Initial Ballot)

Ballot Results

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Standards Drafting Team Vacancies and Nominations

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

Standards Committee Accepting Nominations for Special Election

Several of the ten industry segments that make up the Standards Committee have vacancies. Nominations are being accepted through February 25, 2013 in preparation for a special election to fill vacancies in Segment 2 – Regional Transmission Organizations and Independent System Operators, Segment 5 – Electric Generators, Segment 6 – Electricity Brokers, Aggregators, and Marketers, and Segment 8 – Small Electricity End Users. Further information about the vacancies and a nomination form are available on NERC's website.

Upcoming Events

- Communications in Operations Conference, Atlanta, GA – February 14-15, 2013 (Register)
- Save the Dates for NERC's 2013 Standards and Compliance Workshops
  - March 19-21, 2013 in St. Louis
  - September 24-26, 2013 in Atlanta

OTHER ITEMS

Reliability Assurance Initiative Concept White Papers Posted for Industry Comment

The Reliability Assurance Initiative is for identifying (and implementing where appropriate) changes that enhance the effectiveness of the Electric Reliability Organization (ERO) compliance and enforcement program to avoid cascading events and the resulting major loss of load. Activities include drafting five conceptual white papers ("The Need for Change" and four key change state element papers) that describe the desired end state and change state elements necessary to achieve the attributes of compliance of a mature ERO.

To date, three white papers have been posted to the Reliability Assurance Initiative web page for industry comment and feedback. It is recommended that all Regional Entities and registered entities check the NERC website regularly to ensure the latest version of each paper is being used. Entity comments and responses to posted questions should be submitted to: RAIcomments@nerc.net.

Draft Reliability Guideline Posted for Industry Comment

The North American Electric Reliability Corporation Operating Committee is seeking industry comments on the Draft Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices. Entity comments should be submitted on the posted comment form by February 4, 2013 to reliabilityguidelinecomments@nerc.net.

Upcoming Events

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    - The NERC Reliability Standard Advisory Service (RSA) program is designed to detect and highlight industry difficulties with new reliability standards, and to develop and improve internal compliance approaches prior to each reliability standard's mandatory enforcement date. PER-005-1 was selected as the reliability standard in the initial RSA based on the requirement and unique characteristics of using a systematic approach to establish a training program.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Bulletin

February 4-10, 2013

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STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- None.

Posted for Comment (comment periods close at 8 p.m. Eastern)

- Project 2010-05.1: Protection Systems: Phase 1 Misoperations (PRC-004-3) – Open January 22-February 20, 2013 (Comment Form)
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Upcoming Events
- Project 2010-13.2: Phase 2 of Relay Loadability: Generation – February 13, 2013, 2-4 p.m. Eastern (Register)
- Communications in Operations Conference, Atlanta, GA – February 14-15, 2013 (Register)
- Reliability Standard Advisory Service: PER-005-1 Lessons Learned – March 6, 2013, 1-2 p.m. Eastern (Register)
- Spring Standards and Compliance Workshop, St. Louis, MO – March 19-21, 2013 (Register)

OTHER ITEMS

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Order 754 Data Request Status Report Due March 4, 2013
Each Transmission Planner in the United States that acknowledged that it will be submitting data (last September 2012) has been notified and is required to provide a six-month status report. Canadian Transmission Planners are encouraged to provide a progress status report so that NERC will be able to make a complete account of the activities associated with the data request. Details are available on the project page.

Reliability Assurance Initiative Concept White Papers Posted for Industry Comment

To date, three white papers have been posted to the Reliability Assurance Initiative web page for industry comment and feedback. It is recommended that all Regional Entities and registered entities check the NERC website regularly to ensure the latest version of each paper is being used. Entity comments and responses to posted questions should be submitted to: RAIcomments@nerc.net.

From: NERC Standards Announcements (Do Not Reply)
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - February 11 - 18, 2013
Date: Tuesday, February 12, 2013 5:37:37 PM

Standards Bulletin
February 11 – 18, 2013

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent Board of Trustees adoptions, FERC approvals, and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting and Mallory Huggins with feedback on this bulletin. The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

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STANDARDS ITEMS

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- Project 2007-09: Generator Verification (PRC-024-1) – January 25-Feburary 25, 2013 (Comment Form)
- Rapid Revision Procedure Document – Open February 5-March 6, 2013 (Comment Form)
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    - Supplemental SAR (Comment Form)
    - RSAW (Draft RSAW and Feedback Form)
- Interpretation 2012-INT-04: Interpretation of CIP-007 for ITC – Open February 6-March 22,

2013 (Initial Ballot)

- Interpretation 2012-INT-06: Interpretation of CIP-003 for Consumers Energy – Open February 6-March 22, 2013 (Initial Ballot)

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- Project 2010-13.2: Phase 2 of Relay Loadability: Generation – Open January 25-February 25, 2013 (Join Ballot Pool)
- Interpretation 2012-INT-04: Interpretation of CIP-007 for ITC – Open February 6-March 7, 2013 (Join Ballot Pool)
- Interpretation 2012-INT-06: Interpretation of CIP-003 for Consumers Energy – Open February 6-March 7, 2013 (Join Ballot Pool)

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- Project 2010-13.2: Phase 2 of Relay Loadability: Generation – Open March 1-11, 2013 (Initial Ballot)
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Standards Committee Accepting Nominations for Special Election through February 25, 2013

The Standards Committee currently has vacancies for representatives for Industry Segments 2, 5, 6, and 8. Further information about the vacancies and a nomination form are available on NERC's website.

Upcoming Events

- Project 2010-13.2: Phase 2 of Relay Loadability: Generation – February 13, 2013, 2-4 p.m. Eastern (Register)
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For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You have received this email because you are a registered representative in the Registered Ballot Body.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

December 1, 2012

Members, Reliability Coordinating Committee
and
Members, Task Force on Coordination of Operation
Members, Task Force on Coordination of Planning
Members, Task Force on Infrastructure Security and Technology
Members, Task Force on System Protection
Members, Task Force on System Studies

Re: Minutes of the September 12, 2012 RCC Meeting

Sir / Madam:

Attached are the minutes of the September 12, 2012 meeting of the NPCC Reliability Coordinating Committee, as approved at the November 27, 2012 meeting.

Sincerely,

Phil Fedora

Philip A. Fedora
Assistant Vice President-Reliability Services

cc: NPCC Staff

NORTHEAST POWER COORDINATING COUNCIL
Reliability Coordinating Committee Minutes
September 12, 2012

Mr. Gates called the meeting of the Reliability Coordinating Committee (RCC), held at the New York Times Square Residence Inn by the Marriott on September 12, 2012 to order at 10:00 am.

Attendance

Officers of the Reliability Coordinating Committee

Donald L. Gates, Chair	ISO-New England
Alden Briggs, Co-Vice Chair	New Brunswick System Operator (via phone)
Michael Schiavone, Co-Vice Chair	National Grid USA

Sector 1 - Transmission Owners

Central Hudson Gas & Electric Corp.	Tom Duffy & Frank Pace (Alternate)
Central Maine Power Company	David Conroy (Alternate)
Consolidated Edison Company of New York, Inc.	Peter Yost (Alternate)
Hydro One Networks Inc.	Paul Tremblay (via phone)
Long Island Power Authority	(proxy to Anie Philip)
National Grid USA	Michael Schiavone
New Brunswick Power Transmission Corporation	Randy MacDonald – Alternate (via phone)
New York Power Authority	Michael Parisi – Alternate (via phone)
New York State Electric & Gas Corp.	Ray Kinney – (via phone)
Northeast Utilities	Brad Bentley
Nova Scotia Power Incorporated	David Stanford - Alternate
Rochester Gas & Electric Corporation	John Allen (via phone)
Vermont Transco	Paul Renaud

Sector 2 – Reliability Coordinators

Hydro-Québec TransÉnergie	Pierre Paquet
Independent Electricity System Operator	Barbara Constantinescu
ISO-New England, Inc.	Donald L. Gates
New Brunswick System Operator	Alden Briggs (via phone)
New York Independent System Operator	Dana Walters - Alternate

Sector 3 – Transmission Dependent Utilities, Distribution Companies and Load Serving Entities

Hydro-Québec Distribution	Stephane Dufrense
Long Island Power Authority	Anie Philip - Alternate
New York Power Authority	(proxy to Mike Parisi – via phone)
Northeast Utilities	Dwayne Basler

Sector 4 Generation Owners

Dominion Energy Marking, Inc.	Mike Garton (via phone)
Dynegy, Inc.	Jim Watson (via phone)
Entergy Nuclear Northeast	Tom Czerniewski (via phone)
Long Island Power Authority	(proxy to Anie Philip)
New York Power Authority	(proxy to Mike Parisi – via phone)
NextEra Energy Resources	(via written proxy)
Ontario Power Generation, Inc.	(via written proxy)

Sector 5 – Marketers, Brokers, and Aggregators

Constellation Energy Commodities Group, Inc.	(via written proxy)
Hydro-Quebec Energy Marketing, Inc.	(proxy to Scott Luethaser)
Hydro Québec Energy Services (US) Inc.	Scott Leuthaser – Alternate (via phone)
Long Island Power Authority	(proxy to Anie Philip)
New York Power Authority	(proxy to Mike Parisi)
PPL EnergyPlus LLC	Bradley Weghorst (via phone)
Utility Services	Brian Evans-Mongeon

Sector 6 – State and provincial Regulatory and/or Governmental Authorities

New York Power Authority	(proxy to Mike Parisi)
New York State Department of Public Service	Ed Schrom

Sector 7 – Sub-Regional Reliability Councils, Customers, other Regional Entities and Interested Entities

New York State Reliability Council, LLC	Roger Clayton (via phone)

NPCC Staff

Jack Alvarez	Senior Engineer
Sal Buffamante	Assistant Vice President of Compliance Audits & Investigations
Gerry Dunbar	Manager, Reliability Criteria
Javier Echevarria	Information Technology Specialist
Phil Fedora	Assistant Vice President, Reliability Services
Brian Hogue (via phone)	Information Systems & Security Management
Stan Kopman	Assistant Vice President of Compliance Registration & Enforcement
Quoc Le	Manager, System Planning & Protection

NORTHEAST POWER COORDINATING COUNCIL
Reliability Coordinating Committee Minutes
September 12, 2012

John Mosier, Jr.	Assistant Vice President of System Operations
Lee Pedowicz	Manager, Reliability Standards
Frantz Roc	Manager, Information Technologies
Paul Roman	Manager, Operations Planning
Edward A. Schwerdt	President & Chief Executive Officer

Guests

Brad Bentley	Chair, Task Force on Coordination of Planning
David Daley	Chair, Task Force on Coordination of Operation
Paul DiFilippo (via phone)	Vice Chair, Task Force on System Protection
Gregory Goodrich	Chair, Task Force on Infrastructure Security & Technology
Michael Potishnak (via phone)	ISO-New England
Daren Verner (via phone)	Chair, Task Force on System Protection
Isen Widjaja (via phone)	Chair, SS-38 Working Group

Quorum Statement

Mr. Fedora indicated that a quorum had been achieved, by member attendance, proxy or alternate designation. He also noted having received the following written proxies:

Sector 4 – Generator Owners
Allen Schriver – NextEra Energy Resources
David Ramkalawan – Ontario Power Generation, Inc. (received during the meeting)

Sector 5 – Marketers, Brokers and Aggregators
Glen McCartney – Constellation Energy Commodities Group, Inc.

Antitrust Guidelines for NPCC Meetings

Mr. Fedora reviewed the NPCC Antitrust Guidelines in the Agenda package, and suggested contacting NPCC Inc.'s Assistant Secretary, Andrianne S. Payson, at (212) 424-8218 for further information.

President & CEO Report

Mr. Schwerdt reported that NERC, via a letter request dated June 5, 2012 tasked each of the Regional Entities to assess the actions being taken by registered entities within their

respective footprints to address applicable lessons learned from the joint FERC-NERC report on the Southwest Outage of September 8, 2011. The NERC request was divided into Next-Day and Real-Time Operating issues in the areas of next-day planning, situational awareness, Interconnection Reliability Operating Limits (IROL), protection systems and reclosing, and also Longer-term and Seasonal Planning issues, including planning processes and modeling.

He stated that NPCC's August 30, 2012 transmittal to NERC of thorough and thoughtful assessments conducted by the Task Forces, (included in today's agenda package), represents the most impressive body of work of any of the Regional Entities, and congratulated and thanked the Task Forces for continuing NPCC's culture of excellence. NERC is currently in the process of creating an overall summary document of the industry response, which will be made available to the membership once released.

With respect to WECC's specific responses to the recommendations, he highlighted the following from WECC's recent press release: "WECC has expanded its sharing of next-day studies to improve Situation Awareness; it has identified and calculated IROLs (for the first time); a preliminary analysis of sub-100 kV elements that can impact the BES is being conducted; and WECC has initiated a review of all Remedial Action Schemes. In addition, and arguably most importantly, a fundamental assessment of the WECC corporate structure is underway that will most likely lead to the organizational separation of the Regional Entity and the Reliability Coordinator responsibilities, and a significant strengthening of the RC function in WECC by June of next year."

He further reported that over 60 sets of comments were submitted by the September 4, 2012 deadline in response to the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking indicating its intent to approve both the NERC filed definition for Bulk Electric System, as well as the associated proposed Rules of Procedure changes. NERC utilized the original standard drafting and rules of procedure teams to both interpret FERC's example system configurations, and to clarify any ambiguities in the rules, demonstrating the robustness of the inclusion and exclusion criteria, and the flexibility of the exception process. NPCC joined with all other Regional Entities in general support of the definition and in a commitment to work within the exception process to address any Regional differences within the U.S. systems.

General themes within the other comments included: continued broad general support for the definition within the U.S. with a 24 month implementation period; a consensus that FERC should not be involved in nominating BES facilities; a desire for third party roles in the exception process; significant cost concerns if the bright-line were to be lowered to include sub-100 kV facilities; consensus on including blackstart resources that are identified in restoration plans, but not cranking paths; and numerous and various

recommendations offering clarifications to both the inclusions and exclusions. In addition, comments from Ontario, Quebec and some other entities continue to support a performance based methodology as being more appropriate for determining BES elements, and recommend a cost-benefit analysis prior to the issuance of a FERC order. Current estimates point to a possible FERC BES Order sometime in the 4th Quarter of 2012.

Chair Report

Meeting Agenda

Mr. Gates stated there were no changes to the Agenda provided in the Agenda Package.

The RCC then approved the Agenda.

Development of 2013-2014 Task Force/RCC Work Plans

Mr. Gates reminded the Task Forces of the need to develop their respective 2013-2014 Work Plans for consideration at the next RCC meeting. Following review and approval of their respective plans, the RCC will then approve their proposed 2013-2014 Work Plan.

Nominating Committee

Mr. Gates reminded the RCC that Mr. Briggs would succeeded him as RCC Chair in 2013. He asked for volunteers to form a Nominating Committee to recommend a candidate (or candidates) for Co-Vice Chair for consideration at the November RCC meeting and subsequent NPCC BOD approval. Messrs. Duffy and Ms. Constantinescu volunteered to serve on the Nominating Committing.

Mr. Gates indicated that Mr. Fedora would help to coordinate their efforts. He encouraged anyone interested in the RCC Co-Vice Chair position to contact the Nominating Committee. Mr. Fedora then reviewed the RCC procedures concerning the selection and representation for the RCC Co-Vice Chairs.

2013 RCC Meeting Dates

- ✓ Wednesday, February 27, 2013 – New York City Location - TBA
- ✓ Wednesday, June 5, 2013 – New York City Location - TBA
- ✓ Wednesday, September 11, 2013 – New York City Location - TBA
- ✓ Tuesday, December 3, 2013 – Boston Location – TBA

CIP-002 Version 4 Notifications

Mr. Goodrich explained that the Task Force on Infrastructure Security & Technology has requested assistance from the other Task Forces on CIP-002 version 4 notifications, as described in the Agenda package.

Consent Agenda

The Reliability Coordinating Committee approved the following Consent Agenda items:

June 13, 2012 Meeting Minutes

The Draft-For-Approval Minutes of the June13, 2012 Reliability Coordinating Committee were approved, with minor corrections noted.

RCC Membership Changes

The following change to RCC representations were approved at the June 26, 2012 NPCC Board meeting:

Sector 5, Markerters, Brokers and Aggregators

- ✓ Ms. Elizabeth (Becky) A. Davis of PPL EnergyPlus as an alternate, replacing Mr. Mark Heimbach.

The following change to RCC representations will be sought at the September 12, 2012 NPCC Board meeting:

Sector 4, Generator Owners

- ✓ Ms. Polina Adelson of Long Island Power Authority as an alternate.

Task Force Roster Changes

The following changes to Task Force and Working Group memberships were approved:

Task Force on System Protection

- ✓ Mr. David Mahlmann as a member and Mr. Edwin Cano as the alternate, both of the New York Independent System Operator.
- ✓ Mr. David Bertagnolli replaces Mr. David Forrest as a member, both of ISO-NE.

Task Force on Coordination of Planning

- ✓ Mr. Hung Huynh of Nova Scotia Power, Inc. replaces Mr. Andrew Webb as the alternate.

NPCC Control Perfomance Working Group (CO-1)

- ✓ Mr. Jonathan Pollock succeeds Mr. Alan MacNaughton as the member and Mr. Brad Greer succeeds Mr. Dave Daley as the alternate, both of the New Brunswick System Operator.

Inter-Area Dynamic Analysis Working Group (SS-38)

- ✓ Mr. Shounak Abhyankar and Mr. Anish Joshi as the alternates, both of ISO New England, Inc.

A-10 Implementation Plan Update
Approved as provided in the Agenda Package.

New York 2012 Interim Area Transmission Review
Approved as provided in the Agenda Package.

NPCC 2013 Long Range Adequacy Overview Scope & Schedule
Approved as provided in the Agenda Package.

NPCC Document C-17 - *"Procedures for Monitoring and Reporting Critical Operating Tool Failures"*
Approved as provided in the Agenda Package.

Reliability Coordinating Committee Actions

Retirement of Millstone SLOD Type I Special Protection System (SPS) #23
Mr. Bentley provided an overview of Northeast Utilities plans to remove the above-referenced SPS from service, and referred to the supporting materials provided in the Agenda package. Although the NPCC Special Protection Systems Directory No. 7 does not specify how the retirement of SPSs are to be considered, he reported that both the Task Force on System Studies and the Task Force on Coordination of Planning concur that removal of this SPS does not result in a significant adverse impact once the Millstone area double-circuit tower circuits are separated, and recommends retirement of this SPS after that separation takes place.

The NPCC Reliability Coordinating Committee then approved the Retirement of Millstone SLOD Type I SPS #23 (with one abstention – David Ramkalawan, Ontario Power Generation, Inc., Sector 4), as provided in the Agenda package.

New England – New Brunswick Reserve Sharing Agreement
Mr. Daley reported that the Task Force on Coordination of Operation discussed a proposed reserve sharing agreement between the ISO New England (ISO-NE) and the New Brunswick System Operator (NBSO) that provides for the sharing of up to 200 MW of operating reserve between the NBSO and the ISO-NE.

In its review, the TFCO verified that the reserve sharing agreement will comply with the requirements of NPCC Regional Reliability Reference Directory 6, "Reserve Sharing Groups," and NPCC Regional Reliability Reference Directory 5, "Reserve," ensuring that the operational reliability of the interconnected systems will not be impacted upon the implementation of the agreement.

Accordingly, the Task Force on Coordination of Operation recommended that the RCC approve the NBSO and ISO-NE reserve sharing agreement. Upon its approval, the two parties will conduct the necessary training of its system operators and the agreement will then be implemented.

The RCC then approved the New England – New Brunswick Reserve Sharing Agreement (with one abstention – David Ramkalawan, Ontario Power Generation, Inc., Sector 4), as provided in the Agenda package.

NPCC Regional Reliability Reference Directory No. 5 – "*Operating Reserve*"

Mr. Daley presented a summary of the revised NPCC Directory 5 "Reserve."
He explained that the version of Directory 5 currently in effect had been developed during 2010 by the Task Force on Coordination of Operation (TFCO) with input from the CO-8 System Operation Managers and CO-1 Control Performance Working Groups. It was approved by the NPCC Membership on December 2, 2010.

At that time, there were several unresolved issues in the document that needed refinement. The TFCO, CO-8 and CO-1 Working Groups addressed and resolved those issues during 2011 and the first half of 2012, resulting in the revised version of Directory 5 provided in the Agenda package for RCC approval.

He explained the most significant changes included:

- The implementation of Simultaneous Activation of Reserve (SAR) when the initiating event is a radial source contingency. This required extensive revisions to Appendix 4;
- Determination of the time associated with the loss of a resource; and,
- Various wording revisions to improve clarity throughout the document.

He reported that the TFCO had responded to all comments received during those postings and recommends RCC approval of the document for NPCC Membership ballot approval.

The NPCC Reliability Coordinating Committee recommended NPCC Membership ballot approval (with one abstention – David Ramkalawan, Ontario Power Generation, Inc., Sector 4), of the NPCC Regional Reliability Reference Directory No. 5 – "*Operating Reserve*" as provided in the Agenda package.

Mr. Schwerdt then expressed this appreciation to the TFCO for their efforts in completing this revision, noting its requirements sets NPCC apart from other reserve sharing arrangements.

Mr. Kopman mentioned that he would be following up on the functional model registration requirement for reserve sharing groups, and asked if the announced integration of the NBSO into NB Power would impact the reserve sharing agreement.

Mr. Briggs replied that he did not expect any impact, other than a name change; the NBSO is expected to exist as a legal entity through at least April 1, 2013.

Mr. Mosier also acknowledged the efforts of Mr. Potishnak in the development and revision of the directory.

Status Reports

Mr. Gates referred the RCC to the materials provided in the Agenda package; the RCC discussed the following Agenda items:

NPCC Regional Standards Committee (RSC) Report

Mr. Pedowicz noted that in addition to the materials provided in the Agenda package, the RSC keeps track of NPCC members on NERC Standards Drafting Teams; he reported there exists one opening for a NPCC representation on SDT 2017 –017 - Protection System Maintenance and Testing.

He also mentioned the Executive Tracking Summary available on the NPCC website that summarizes NERC related Standards activities.

NPCC Disturbance Monitoring Equipment Reliability Standard (PRC-002-NPCC-1)

Mr. Verner described the Task Force on System Protection (TFSP) concerns regarding potential compliance issues related to the approved revised Bulk Electric System (BES) Definition and the present wording of NPCC Disturbance Monitoring Equipment (DME) Reliability Standard (PRC-002- NPCC-1) provided in the Agenda package.

He said that this Standard is applied to the Bulk Electric System, which is presently defined in NPCC to be the Bulk Power System, as determined by the Document A-10 Criteria, *Classification of Bulk Power System Elements*. He explained that it was the understanding of the Standard Drafting Team, the TFSP, and all who participated in the development and approval of this Standard that, although the BES definition may change, the basic applicability of the standard would not.

The Standard was approved with a 4-year Implementation Plan with the first milestone scheduled to be completed in October 2013.

Mr. Yost stated that while Con Edison is not opposed to the technical aspects of the DME Standard and applying the Standard to all BES facilities, even if the BES is 100 kV and above; Con Edison believes the 4-year implementation plan, which was approved by FERC along with the Regional Standard, is too short to permit complete DME installation, including 100 kV and above facilities.

He said that Con Edison requests that NPCC Staff pursue with NERC and FERC an extension of the implementation period from 4 years to ten (10) years to permit adequate time for 100% compliance, assuming the BES is defined as 100kV and above. Con Edison is willing to provide NPCC Staff with any technical information required to substantiate the time extension request.

It was noted that if a RSAR proposing substantive language changes to the DME Standard was submitted to address the TFSP's concerns, it would require the necessary technical justification for the change.

After discussion, the RCC directed Mr. Pedowicz to work with the TFSP to provide an interpretation of the DME requirements to clarify its applicability, and provide a progress report for the November RCC meeting. The RCC also directed the TFSP to consider an extension to the DME implementation plan in addition to any changes to the DME Standard (a two-track approach). This appeared to be the most expedient approach, given the options presented. Mr. Verner agreed that this could be a workable solution, and would add the assignment to the TFSP's Work Plan. He indicated he would make discussion of the suggested DME interpretation approach a priority at upcoming TFSP meetings.

Mr. Kopman stated that from an enforcement point of view, only violations of the interpretations would be enforceable.

Reliability Directory Status

Mr. Dunbar said, in addition to the materials provided in the Agenda package, Directory No. 12 was been posted for NPCC Open Process comments on the proposed revisions to the UFLS tolerances, as developed by the SS-38 Working Group, and approved by the Task Force on System Studies.

NPCC Compliance Committee Report

Mr. Gates referred the RCC to the materials provided in the Agenda package.

SS-38 Working Group Load Modeling White Paper

Mr. Widjaja provided an update on the SS-38 Working Group's progress on the Load Modeling White Paper. He reported that over the next couple of months, the SS-38 Working Group will be conducting simulations of various load models, and will be reviewing and analyzing the results. In addition, the SS-38 Working Group plans to hold a joint meeting with the WECC Load Modeling Task Force and the WECC Model Validation Working Group in early November to share and learn more from their load modeling experiences.

He said that the SS-38 Working Group expects to document the results of its load modeling study effort during the January - February 2013 timeframe and plans on completing the report for TFSS review and subsequent approval recommendation at the February 2013 RCC meeting.

Status of NERC Alter-Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility ratings.

Mr. Mosier reported on the status of the NERC Alert, "Consideration of Actual Field Conditions in Determination of Facility Ratings" provided in the Agenda package.

2012-2013 Task Force Work Plan Progress

Task Force on Coordination of Operation (TFCO)

Mr. Daley updated the RCC on the following TFCO activities:

- ✓ Directory No. 6 approval;
- ✓ Directory No. 5 completion;
- ✓ Development of the Operational Sections of Directory No. 1;
- ✓ The Fall System Operator Seminar scheduled for November 7-8, 2012 in Montreal;
- ✓ Addressing the Recommendations from San Diego disturbance report of September 8th;
- ✓ New version of Directory No. 8 (System Restoration); and,
- ✓ Wide Area Restoration Drill scheduled to be held in October 2012.

Task Force on Coordination of Planning (TFCP)

Mr. Bentley provided an update on the following TFCP activities:

- ✓ Review of A-10 implementation plans;
- ✓ Review of Interim and Comprehensive NPCC Adequacy Reviews;
- ✓ SPS changes; and,
- ✓ TFCP Directory No. 1 completion - to be send to the CP-11 Working Group once TFCO effort is completed.

He thanked the members of the TFCP for their help in the development of the NPCC response to the recommendations from the NERC Southwest Blackout report.

Task Force on Infrastructure Security & Technology (TFIST)
Mr. Brian Hogue reported on the following TFIST activities:

- ✓ CIP2 version 4 - third part notification issue; and
- ✓ The Third posting of CIP v5 30 day comment period

Task Force on System Protection (TFSP)
Mr. Verner reported on the following TFSP activities:

- ✓ Ongoing PRC-002 review; and,
- ✓ Progress on Directory No. 4 and No. 7.

Task Force on System Studies (TFSS)
Mr. Conroy reported on the following TFSS activities:

- ✓ Special Protection System changes;
- ✓ Area Transmission Reviews; and,
- ✓ BPS List changes.

NPCC Reliability Assessment Program (NRAP) Highlights Report
Mr. Fedora indicated that the NPCC Reliability Assessment Program Highlights Report Area has been be updated as of August 31, 2012 and is posted on the NPCC website.

NERC Highlights and Agenda Items

Operating Committee (OC)
Mr. Mosier reviewed the following items from the September 2012 NERC Operating Committee Agenda:

- ✓ Discussion of Recommendations and Conclusions from the Arizona-Southern California Outage report to identify follow-up actions;
- ✓ Approval of Reliability Guideline – System Operator Verbal Communications; and,
- ✓ Roundtable discussion of NERC Standard PRC-001 – Requirements.

Planning Committee (PC)
Mr. Fedora highlighted the following items from the September 2012 NERC Planning Committee Agenda:

- ✓ Approval of the Frequency Response Initiate Report;
- ✓ Approval of the Integration Variable Generation Task Force Task 1-3 Report;
- ✓ Approval of the data request for TADS 100-199kV Automatic Outage Data; and,
- ✓ Status report on the Bulk Electric System Standard Drafting Team Phase 2 assignments.

Critical Infrastructure Protection Committee (CIPC)
Mr. Hogue highlighted the following issues scheduled for voting at the June 2012 NERC Critical Committee Agenda:

- ✓ Formation of additional CIPC Subcommittees – two Charters, Compliance & Enforcement Input Working Group and the Cyber Security Analysis Working Group;
- ✓ 2012 Grid Security Conference; and,
- ✓ Third posting of CIP version 5.

Mr. Goodrich said that the CIPC and the Cyber Security Groups are looking for more volunteers, in order to have additional representation from the NPCC Region.

Informational Items

Mr. Gates referred the RCC to the materials included in the Agenda package. The following Informational Items were discussed at the meeting:

NERC Working Groups/Task Forces

Mr. Fedora referred to the summaries of the activities of the following NERC Task Forces and Working Groups included in the Agenda package:

- ✓ NERC Protection System Misoperations Task Force;
- ✓ Generator Availability Data System Working Group;
- ✓ Model Validation Task Force;
- ✓ Demand Response Availability Data System Working Group; and,
- ✓ Transmission Availability Data System Working Group.

Bulk Electric System (BES) Definition Related Activities

Mr. Fedora stated the BES Definition Guidance Document is expected to be released for Stakeholder comment in September. A Charter for the development of an IT tool for BES Exception Processing and corresponding RFP for the software development are being coordinated by the Regions and NERC's Project Management Organization.

Eastern Interconnection Planning Collaborative (EIPC)

Mr. Gates provided a brief summary of recent EIPC activities. The EIPC has started to discuss its activities post DOE funding.

Eastern Interconnection Reliability Assessment Group (ERAG)

Mr. Roman summarized the ERAG Management Committee June 12, 2012 meeting, provided in the Agenda package. He reported that he has provided presentations on frequency response modeling at the EPRI / North American Transmission and Generator Forum Workshop on July 10 – 11, 2012 in Palo Alto, California, continuing the dialog with the generator operators regarding the improvement of their models.

He also reported that ERAG is providing on-going input and coordinating with the North American Transmission Forum regarding improvement in modeling practices. The next

ERAG Management Committee meeting will be held at the MRO Office in St. Paul, Minnesota on September 26, 2012.

FERC Gas-Electric Coordination Technical Conferences

Mr. Fedora referred the RCC to the presentations given at the "Coordination Between Natural Gas and Electricity Markets" FERC Technical Conferences (FERC Docket No. AD12-12-000) provided in the Agenda package.

NPCC 2012 General Meeting

Mr. Fedora reviewed the Agenda for the 2012 NPCC General Meeting, to be held at the Omni Mount Royal Hotel in Montreal, Quebec on November 28, 2012, and plans for a NPCC Governmental/Regulatory Affairs Advisory Group Meeting. Ms. Constantinescu added she would be available to provide a status update of Ontario plans to implement a BES Exception Process under the IESO Market Rules at the NPCC Governmental/Regulatory Affairs Advisory Group Meeting.

Other Matters

Having no other items to consider, the RCC meeting was then adjourned.

Next RCC Meeting Date	**Location**
November 27, 2012	Montreal, Québec

Distribution of Approved Minutes

NPCC Full & General Member Representatives and Alternates
Members, NPCC Board of Directors
Members, NPCC Reliability Coordinating Committee
Members, NPCC Public Information Committee
Members, NPCC Compliance Committee
Members, NPCC Regional Standards Committee
Members, NPCC Task Force on Coordination of Operation
Members, NPCC Task Force on Coordination of Planning
Members, NPCC Task Force on Infrastructure Security and Technology
Members, NPCC Task Force on System Protection
Members, NPCC Task Force on System Studies
NPCC Officers
NPCC Staff
Andrew J. Fawbush, Esq.
Andrianne S. Payson, Esq.
and

Federal Energy Regulatory Commission – Mike Bardee, Juan Villar
La Régie de L'Énergie – Caroline Dupuis
Ontario Energy Board – Peter Fraser
United States Department of Energy – David Meyer
New Brunswick Department of Energy – Stephen Waycott
Nova Scotia Utility & Review Board – S. Bruce Outhouse, Q.C.

NPCC, Inc.

AGENDA

Meeting No. 13
NPCC Governmental/Regulatory Affairs Advisory Group

Omni Mount Royal
1050 Sherbrooke Street West
Montreal, Quebec H3A 2R6

November 27, 2012 – 1:30 PM

Teleconference Information:
Call: (719) 785-1714
Code: 8093

Item	Description	Action	Est. Time
1.	Convene Meeting	Introductions – Carolyn O'Connor, Chair Anti-Trust Compliance Guidelines Roster Update	1:30 - 1:45
2.	Canadian Bulk Electric System Exception Process	Ontario – Barbara Constantinescu, IESO Quebec - Sylvain Clermont, Hydro-Quebec TransEnergie Maritimes – Alden Briggs, NBSO	1:45 – 2:30
3.	Updated NERC Reliability Impact of Environmental Regulations	Status – John Moura, NERC	2:30 – 3:00
4.	Electric Power Dependencies on Natural Gas	NERC Study Status John Moura, NERC	3:00 – 3:30
		Status of Multi-Regional Natural Gas Study Mark Babula, ISO-NE	3:30 – 4:00
5.	Regional Planning Updates	New York – John Buechler, NYISO New England – Anne George, ISO-NE Eastern Interconnection Planning Collaborative – John Buechler	4:00 – 4:50
6.	Next Meeting(s)	All	4: 50 – 5:00

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Power to Ontario.
On Demand.

Ontario Bulk Electric System (BES) Exception Procedure

Presentation to

NPCC - Governmental/Regulatory Affairs Advisory Group

November 27, 2012





Ontario BES Exception Procedure Background

- FERC issued Order 743 on November 18, 2010 directing NERC
  - to revise the definition of "bulk electric system" to a bright line threshold of 100 kV
  - to adopt an exemption process and criteria for excluding facilities that are not necessary to operate an interconnected electric transmission
- NERC produced a new BES definition and revised its Rules of Procedure (RoP) to include a BES Exception Process.
- NERC's Rules of Procedure allow Canadian and Mexican entities to establish a procedure comparable to NERC's procedure for BES Exception requests.
- Work to develop an Ontario-specific BES exception process was initiated in fall 2011.

Ontario BES Exception Procedure Market Rule Amendments

- Ontario Market Rule Amendments were required in order to:
  - Grant the IESO authority to establish an Ontario BES Exception Procedure.
  - Grant the IESO Board authority to approve or disapprove BES Exception requests.
  - Permit market participants who own elements and facilities or connection applicants to use the Ontario BES Exception Procedure.
  - Allow the IESO to recover costs associated with assessing and processing BES Exception requests.
  - Grant right of appeal to a market participant whose BES exception request is denied.
- Market Rule Amendments were approved by the IESO BoD September 7, 2012.

Ontario BES Exception Procedure Stakeholder Participation

- Open Stakeholder Engagement Process
  - SE-100 stakeholder engagement group to assist in the development of the BES exception process.
  - Stakeholders expressed a need for criteria to be outlined upfront so that they can determine whether to pursue an exception and the likelihood of being successful.
  - A technical sub-committee with stakeholder participation has been established to analyze and test assessment criteria.

Ontario BES Exception Procedure Governance

- BES exception requests in Ontario will be administered and reviewed by IESO staff.
- Adjudication will be performed by the IESO Board of Directors.
- Per its legislative authority, the IESO can, at anytime, deem a facility to be material to the reliability of the IESO-controlled grid and designate it as part of the BES.

Nr	Step	NERC BES exception process	Ontario BES exception process
1	Prepare BES exception request	Applicant, Reliability Coordinator	Applicant
2	Initial screening of request	Regional Reliability Organization	IESO
3	Substantive review	RRO	IESO
4	Technical review/recommendation	RRO panel	IESO
5	Filing of Supplementary evidence	Applicant, RC	Applicant
6	Decision on BES exception request	NERC panel	IESO BoD
7	Challenge of decision	NERC Rules of Procedure	Market Rules dispute resolution

Comparison of NERC and Ontario BES Exception Processes

Ontario BES Exception Procedure Key Elements

- Procedure Structure
  - The Ontario BES Exception Procedure has been fashioned after NERC's "*Procedure for Requesting and Receiving and Exception from the Application of the NERC Definition of Bulk Electric System": Appendix 5C to the Rules of Procedure* and includes the same key sections:
    - Basis for Approval of an Exception.
    - Submission of an Exception Request.
    - Review, Acceptance or Rejection, Regarding Exception Requests.
    - Approval or Disapproval of an Exception Request.
    - Dispute Resolution Process (Right of Appeal).
    - Implementation Period for Exceptions.
    - Amendment, Termination or Transfer of an Approved Exception.
    - Detailed Information to Support an Exception Request.

Ontario BES Exception Procedure Assessment Criteria Development

- Procedure development complete - Phase 1 of SE-100
- Assessment criteria development – Phase 2 of SE-100
- Challenges arise in determining the appropriate evaluation criteria to be used to assess exception requests
- These challenges include:
  - Ensuring the new BES definition is adhered to while determining the circumstances when a variation from the new BES definition would be appropriate.
  - Selecting criteria that would allow requests for exception to be processed in a timely fashion.
  - Determining an appropriate and effective framework or order that the criteria will be used to perform the assessments.

Ontario BES Exception Procedure Assessment Criteria

- Selected criteria should best reflect the reliability values/policies of Ontario.
- The extent of variation comes into play when considering:
  1. Material impact assessment.
  2. Local area definition.
  3. Historical and current application of facilities for the reliability of the Ontario power system.
  4. Reliability benefits commensurate to costs for transmission system investments.
- Ontario has chosen to explore the use of existing general and technical criteria rather than develop new criteria.

Ontario BES Exception Procedure Principles for Assessments

- The following three principles will be followed for the determination of assessment criteria:
  - Transparency
    - Use of Existing Principles; close alignment with the reliability practices in neighbouring jurisdictions and NPCC.
  - Consistency
    - Consideration of existing definitions; NPCC BPS, CIP CEI.
  - Fairness
    - Similar treatment for all exception applicants.

Ontario BES Exception Procedure

- For further information on BES Exception Procedure development and implementation please visit the following web links:
  - SE-100 stakeholder engagement:
    http://www.ieso.ca/imoweb/consult/consult_se100.asp
  - Pending Changes:
    http://www.ieso.ca/imoweb/changes/changeNoticeList.asp
  - Market Rule Amendments (MR-00394)
    http://www.ieso.ca/imoweb/amendments/mr_Amendments.asp

Ontario BES Exception Procedure

Thank You!



NBSO BES Update

NPCC Governmental/Regulatory Affairs Advisory Group

Alden Briggs

November 27, 2012

Approach

- **Define BES in NB regulations**
- **Draft based on A10 and Generator materiality**
- **NERC BES is not carried into NB through the adoption of standards**
- **NB does not plan to adopt the NERC Rules of Procedure that contain the exception process**

NBSO ERNB

Applicability

- **BES definition would only apply to NB**
- **NB does not have authority to define BES for NS and PEI**
- **Maritimes would strive to achieve common definition**
- **NLFD plans are not known at this time. They need to decide prior to connecting to the Maritimes which is expected in the 2017 timeframe.**

NBSO ERNB

Final Decision

- **NB desires to maintain uniformity with the rest of NPCC**
- **Final decision on BES rests with NB DOE and NB EUB**
- **Decision could be challenged on the basis of cost versus benefit to reliability**

NBSO ERNB

Any Questions?



NBSO
ERNB

Eastern Interconnection Planning Collaborative

Eastern Interconnection Planning Project Status

John P Buechler
NYISO Executive Regulatory Policy Advisor

NPCC Governmental/Regulatory Affairs Advisory Group Meeting
November 27, 2012
Montreal, Quebec

Project Overview

- Phase 1 – 11/20/09 to 12/16/11
  - Establish Stakeholder Steering Committee (SSC)
  - Roll-up and integration of regional plans for 2020
  - 8 Macroeconomic “futures”
    - Input assumptions determined by states/stakeholders
    - Up to 9 sensitivities of input variables on each “future”
  - Phase 1 Report
- Phase 2 – 1/1/12 to 12/31/12
  - 3 Future resource scenarios with fully developed transmission build-out options that meet reliability requirements
  - Phase 2 Report

Project Schedule Overview

- Phase 1 Schedule – 11/20/09 to 12/16/11
  - Phase 1 work completed 12/23/11
  - Phase 1 report posted on EIPC website
- Phase 2 Schedule – 1/1/12 to 12/31/12
  - Phase 2 process documents drafted and reviewed with stakeholders during Fall, 2011
  - Currently working on:
    - Finishing transmission “build-outs”
    - Production cost modeling
    - Developing capital cost estimates
    - Phase 2 report

Overarching Observations

- The stakeholder process is functioning in a robust and active manner
  - Stakeholder Steering Committee
  - Consensus based
  - Active and intense dialog
- Excellent working relationship between the state's organization (EISPC) and EIPC
- Stakeholder education on planning processes has been a key part of the project

Phase 1 Resource Expansion Futures

1. "Business as Usual" – assumes present trends continue
2. Federal Carbon Constraint: National Implementation
3. Federal Carbon Constraint: Regional Implementation
4. Aggressive Energy Efficiency, Demand Response, Distributed Generation and Smart Grid
5. National RPS: National Implementation (top down)
6. National RPS: State and Regional Implementation
7. Nuclear Resurgence
8. Combined Federal Climate and Energy Policy Future

Phase 2 – 3 Scenarios

1. **“Combined Federal Climate and Energy Policy”**
   - National carbon constraint with 42% reduction in 2030 and 80% in 2050, 30% national RPS, increased Energy Efficiency/Demand Response/Distributed Generation/Smart Grid [F8S7]
2. **“National RPS- Regional Implementation”**
   - Regionally Implemented 30% National RPS [F6S10]
3. **“Business As Usual”**
   - Includes EPA “non-carbon” regulations & existing state RPS and EE programs
   - No new policies or regulations on carbon, no new RPS, no new EPA regulations [F1S17]

Installed 2030 EI Capacity by Type: 3 Scenarios

		Scenario 3	Scenario 2	Scenario 1
		Installed Capacity in 2030		
		F1S17	F6S10	F8S7
	Total	BAU	Hard	Flat
	2010	Base	Limit	CO2
Coal	272	199	178	10
Nuclear	100	105	105	134
CC	133	202	157	208
CT	120	132	134	66
Steam Oil/Gas	75	36	38	4
Hydro	45	45	52	50
On-Shore Wind	19	68	159	261
Off-Shore Wind	0	2	38	2
Other Renewable	4	14	37	12
New HQ/Maritimes	0	0	1	5
Other	17	17	17	17
Total w/o DR	783	818	916	770
DR	33	71	71	152
Total w/DR	816	889	987	923

2030 Energy Source: 3 Scenarios

- EI generation as a percent of demand, EI energy demand , and EI CO_2 emissions are shown below for 2030

	Scenario 3	Scenario 2	Scenario 1
	BAU	Reg RPS	Nat'l CO2
	F1S17	F6S10	F8S7
CC	25%	13%	26%
Coal	38%	33%	0%
Nuclear	22%	23%	35%
On-Shore Wind	5%	13%	27%
Off-Shore Wind	0%	4%	0%
Hydro	5%	6%	8%
Total	96%	91%	96%
Demand (TWh)	3702	3609	3008
Change from BAU		*-3%*	*-19%*
CO2 (MilMetricTons)	1716	1316	264
Change from BAU		*-23%*	*-85%*

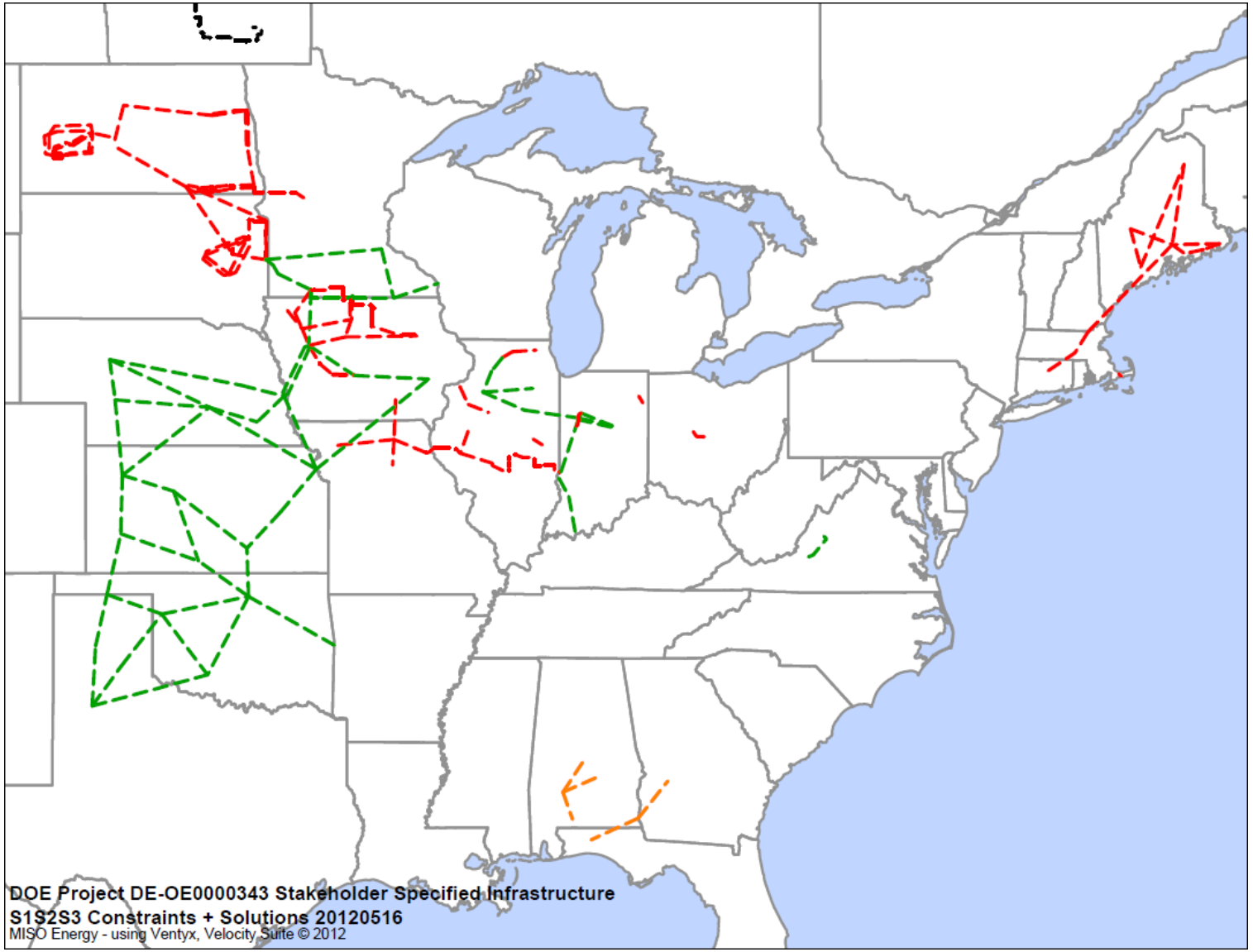
Phase 2 – Transmission Analysis

- The Study Year is 2030
  - Transmission additions required to meet reliability testing consistent with NERC standards
  - Five tests: N-0, N-1, N-G-1, common tower, bus fault >300kV
- Production Cost (annual) for Each Scenario
  - Sensitivity analysis included
- Estimate of the Costs for Generation and Transmission Expansion
- **Deliverable: Transmission options to support each of the resource scenarios … NOT a "Plan."**

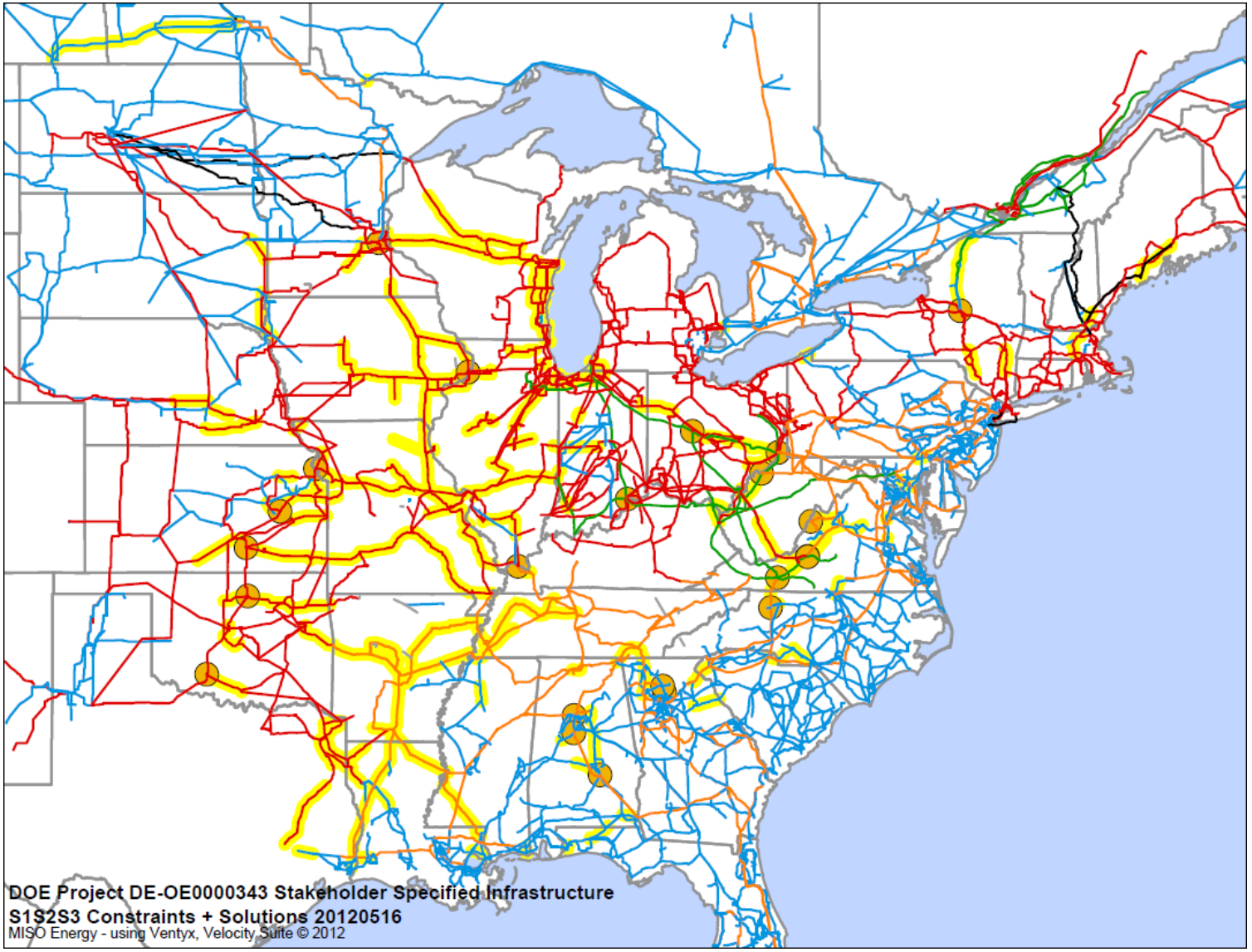
Scenario 1 – Combined Policy (low CO_2)

- Case Development
  - N-0/N-1 Contingency Analysis
  - Transmission Build-out:
    - Over 290 Generation Interconnection projects
    - Over 325 Constraint Relief projects
    - 6 HVDC lines
- Reliability Testing Complete
  - **Map -** http://www.eipconline.com/uploads/20120627_EIPC_SSI_S1S2S3_Constraints_Solutions_draft.pdf

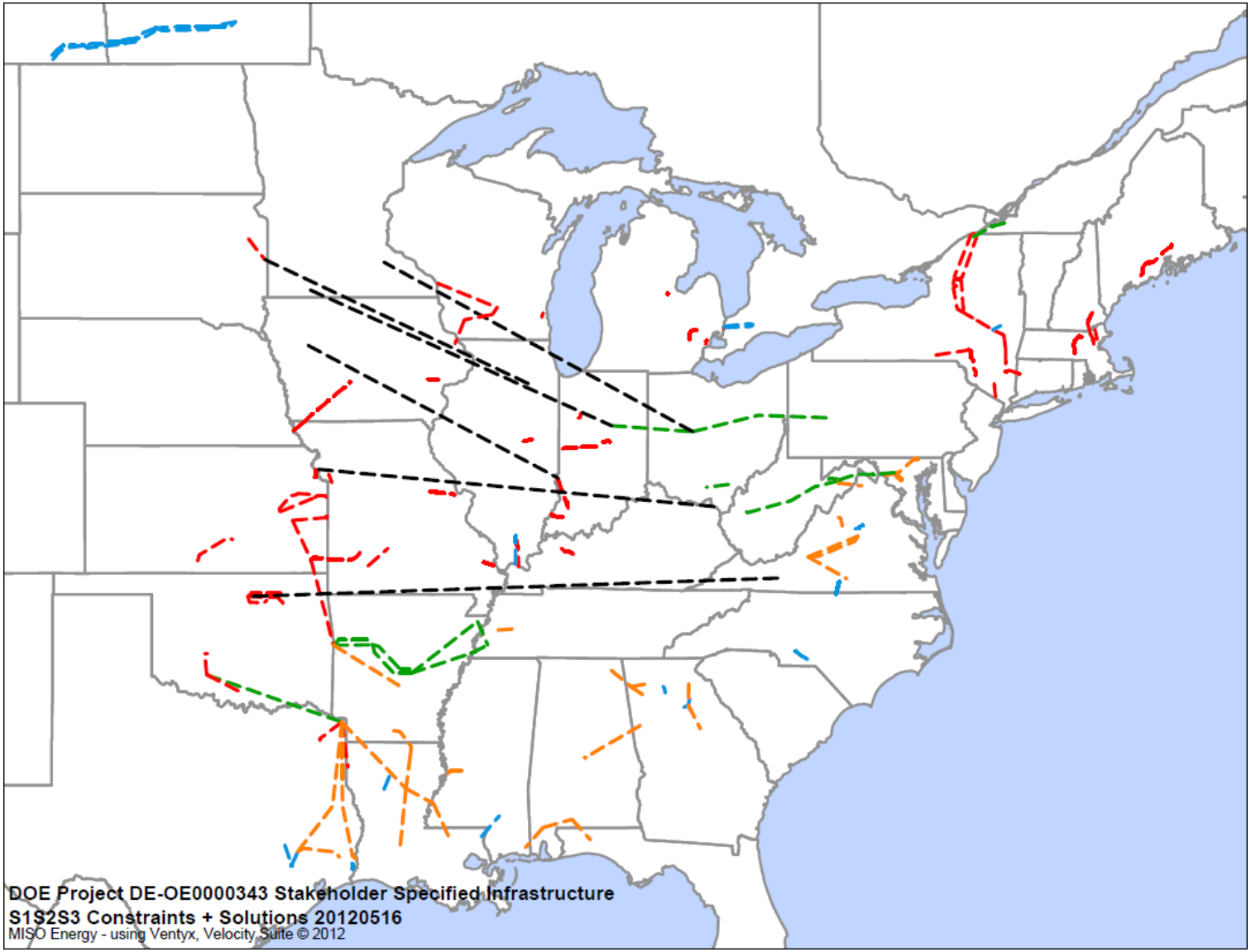
Scenario 1 – Generation Interconnections



Scenario 1 - Constraints



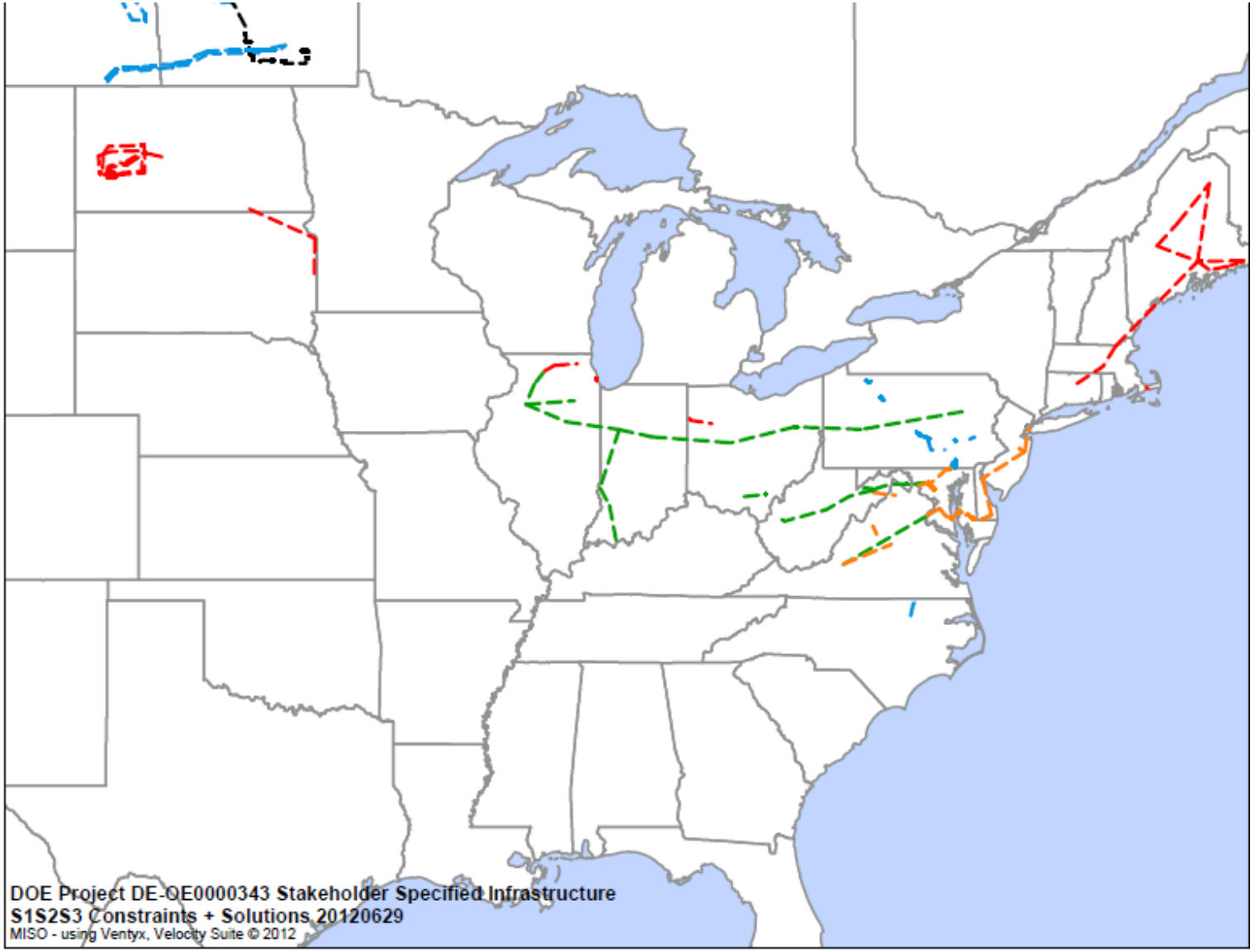
Scenario 1 – Constraint Relief



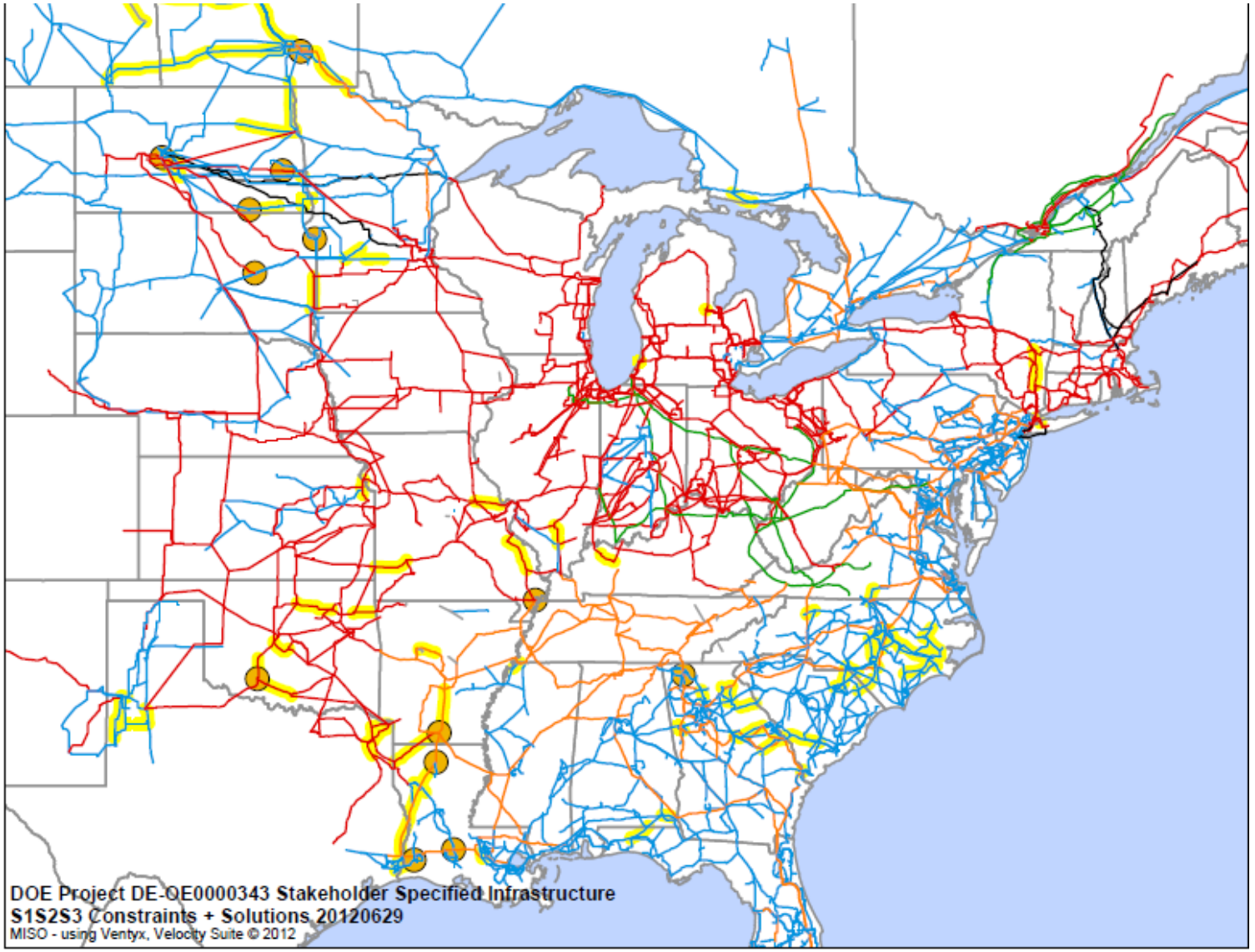
Scenario 2 – RPS/Regional Implementation

- Case Development
  - N-0/N-1 Contingency Analysis
  - Transmission Build-out:
    - Over 280 Generation Interconnection projects
    - Over 200 Constraint Relief projects
    - No new inter-regional HVDC lines –(one within New York)
- Reliability Testing Complete
  - **Map -** **http://www.eipconline.com/uploads/20120627_EIPC_SSI_S1S2S3_Constraints_Solutions_draft.pdf**

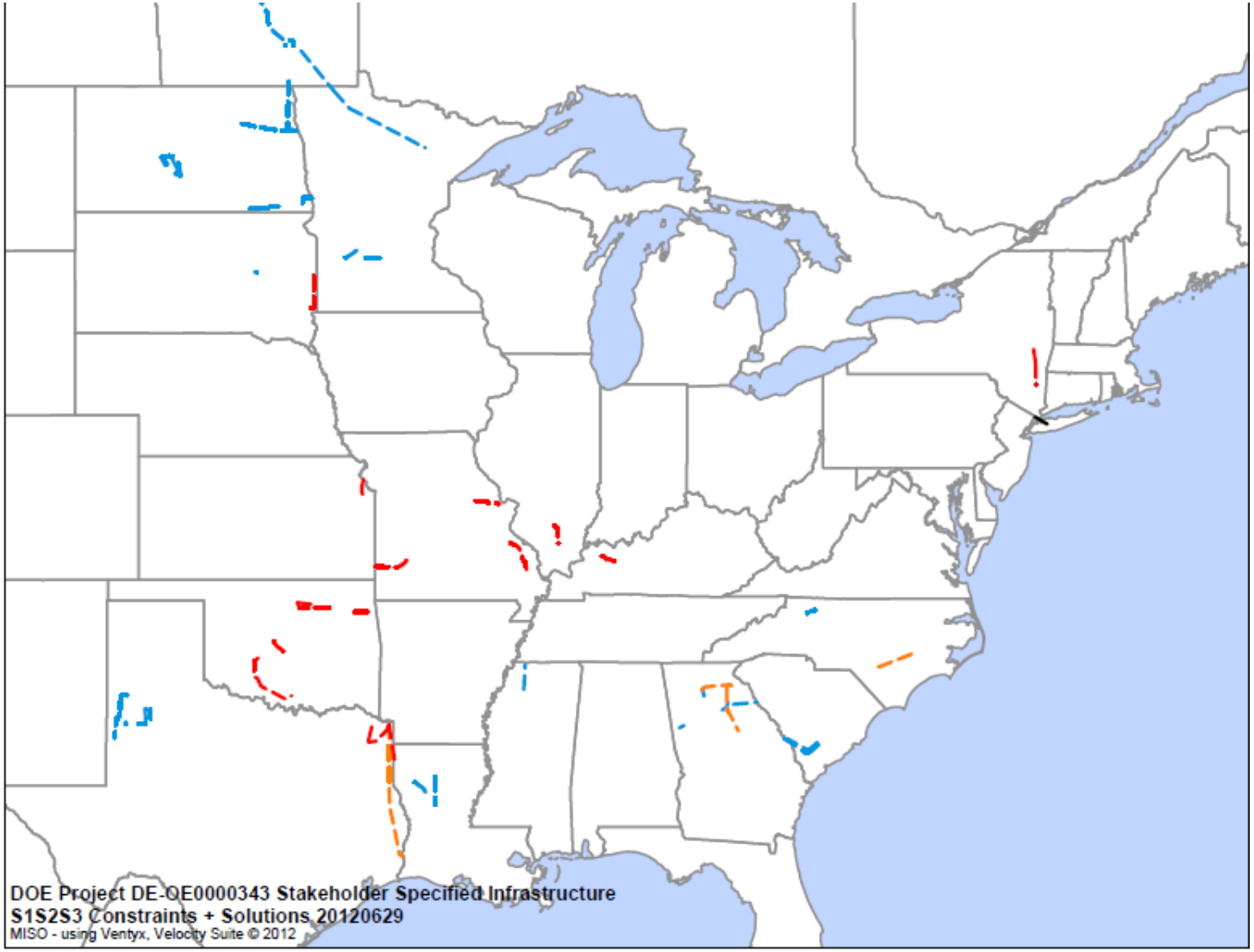
Scenario 2 – Generation Interconnections



Scenario 2 - Constraints



Scenario 2 – Constraint Relief



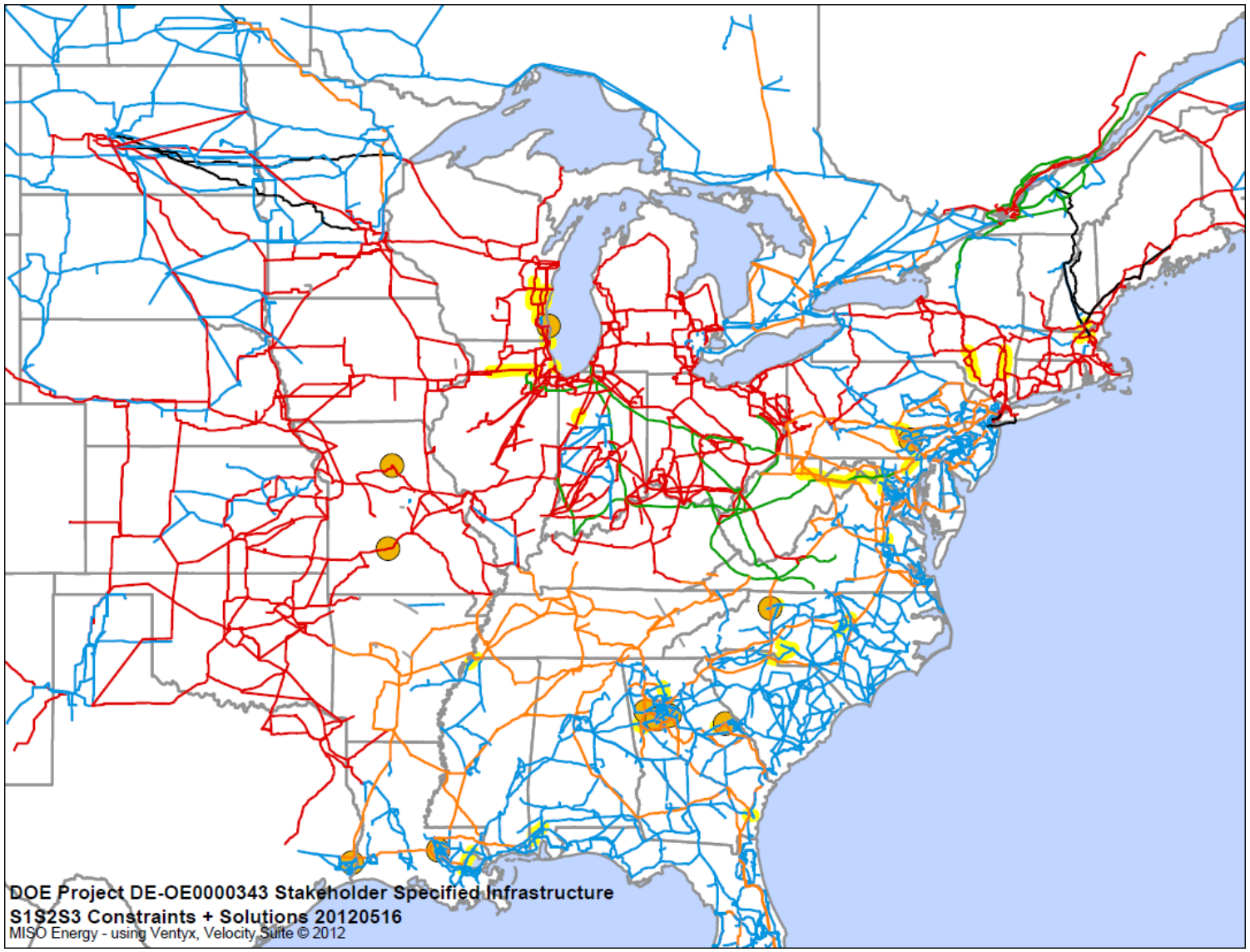
Scenario 3 – "Business As Usual"

- Case Development
  - N-0/N-1 Contingency Analysis
  - Transmission Build-out:
    - Over 50 Generation Interconnection projects
    - Over 165 Constraint Relief projects
    - No new HVDC lines
- Reliability Testing Complete
  - **Map -** http://www.eipconline.com/uploads/20120627_EIPC_SSI_S1S2S3_Constraints_Solutions_draft.pdf

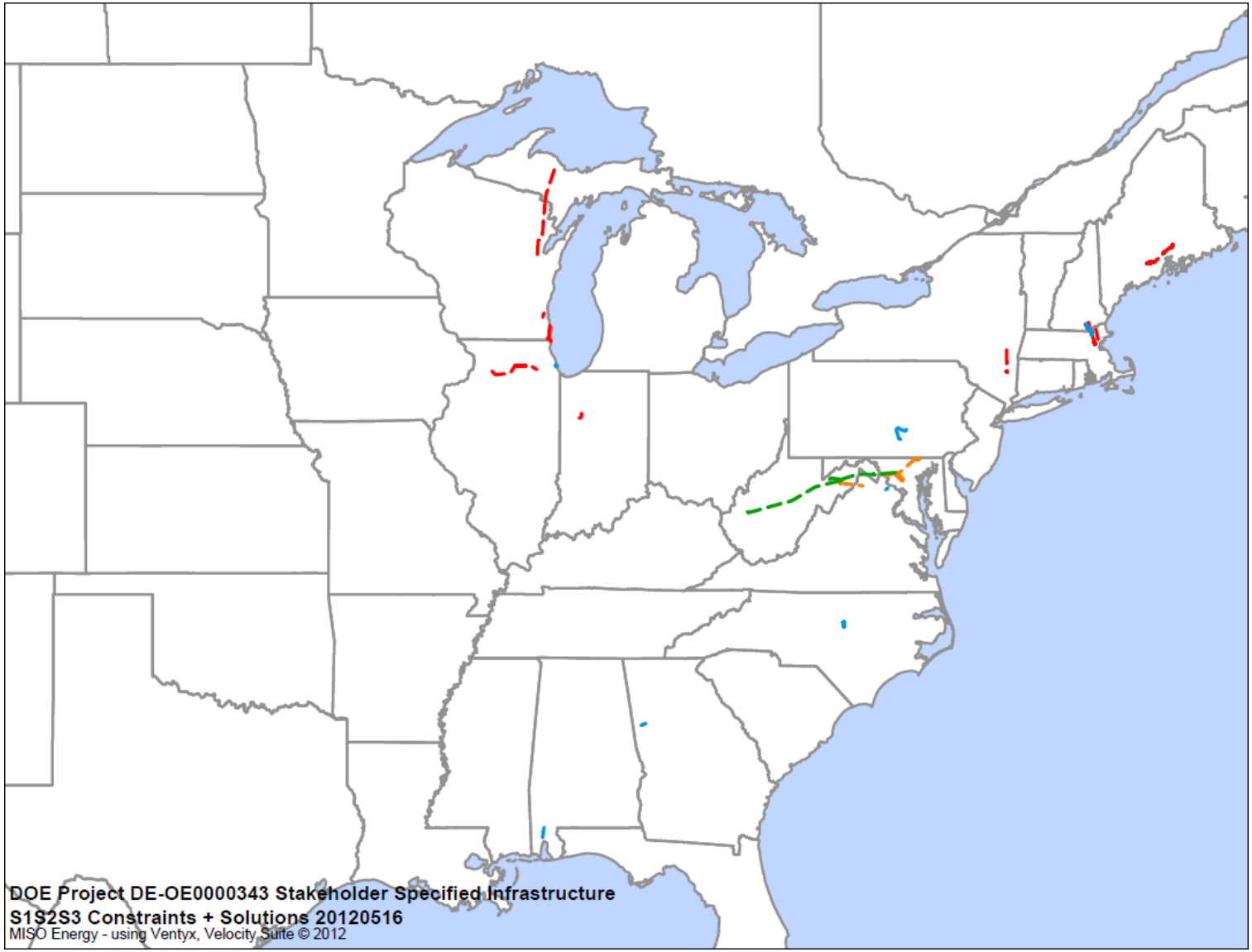
Scenario 3 – Generation Interconnections



Scenario 3 - Constraints



Scenario 3 – Constraint Relief



FERC Order 1000: Transmission Planning & Cost Allocation NYISO Compliance Update

by
John P. Buechler
NYISO Executive Regulatory Policy Advisor

NPCC Governmental/Regulatory Affairs Advisory Group
November 27, 2012
Montreal, Quebec CA

Overview

- **Background – Order 1000**
  - *Compliance Schedule*
- **NYISO/NYTO's October Compliance Filing**
  - *Regional Planning*
  - *Non-Incumbent Issues*
  - *Public Policy Requirements*
- **Interregional Planning & Cost Allocation**
  - *Summary*
  - *Status*

Background

- **FERC Order 1000: Final Rule on Transmission Planning & Cost Allocation**
  - ***Issued on 7/21/11*** *(Docket RM10-23-000)*
  - ***Largely adopts the proposals from the June 2010 NOPR***

- **FERC Rehearing Orders 1000-A & 1000-B**
  - ***Reaffirmed requirements of the Final Rule***
  - ***Provided clarifications—including inter-regional issues***
  - ***Dismissed jurisdictional challenges***
    - **Numerous appeals have been filed in federal court**
    - **Appeals on hold pending FERC response to Order 1000-B rehearing**

- **This presentation provides a status update on NYISO compliance**

Compliance Schedule

- **Effective Date of Final Rule**
  - ***60 days from publication in Federal Register – Oct 11, 2011***
- **Compliance filing is required on everything except interregional planning and interregional cost allocation**
  - ***NYISO/NYTOs submitted joint compliance filing on Oct 11, 2012***
- **Compliance filing on interregional planning & cost allocation**
  - ***Due 18 months from Effective Date of Final Rule – April 11, 2013***

- **Final Rule's requirements will apply only to "new transmission facilities"**
  - ***After the Effective Date of the compliance filings (e.g. – after FERC Approval)***

NYISO/NYTOs Joint October 2012 Compliance Filing

Regional Issues

Compliance Filing Process

- NYISO & NYTOs have a joint compliance obligation under Order 1000
- Ten meetings were held to discuss and receive stakeholder input on the regional planning issues:
  - *Regional planning & cost allocation*
  - *Non-incumbents*
  - *Public Policy Requirements ("PPRs")*
- Despite this extensive consultation process, consensus was not achieved on all issues
- PPR was the most controversial issue
- Joint compliance filing was made on Oct 11, 2012

Regional Planning

Order 1000 Requirements:

- **All transmission providers must have a regional transmission planning process in place that meets Order 890's nine Planning Principles and includes development of a comprehensive system plan**
- **Cost allocation must comply w/Order 1000's Six Principles**

Joint Compliance Filing:

- **NYISO has already been found compliant with Order 890's Planning Principles by the Commission for its reliability and economic planning processes**
- **Compliance demonstrated in filing letter including references to FERC's Order 890 Compliance Orders**
- **Order 1000 Cost Allocation principles added to tariff**

Non-Incumbent Transmission Providers

Order 1000 Requirements:

- **Final Rule eliminates the right-of-first refusal ("ROFR") tariff provisions for incumbent transmission providers with respect to building proposed facilities that are included in a regional transmission plan**
  - ***Several exceptions are granted for local facilities/upgrades /use of existing ROWs***

Joint Compliance Filing:

- **NYISO tariff does not have any ROFR provisions**
- **NYISO planning process contains provisions for non-incumbents to participate on an comparable basis**
- **Tariff revisions were made to incorporate:**
  - **Non-discriminatory qualification criteria**
  - **Detailed information requirements for proposed transmission projects**
  - **Other specific requirements of Order 1000**

Public Policy Requirements

Order 1000 Requirements:

- **Local & regional planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations**
- **No requirement to go beyond existing laws or regulations—but permitted on a voluntary basis**
- **Allows for regional flexibility in meeting this requirement**
- **Not intended to infringe on state authority**

Joint Compliance Filing:

Proposed PPR process includes:

- ***Identification of transmission needs driven by public policy requirements***
- ***Opportunity for stakeholders to propose solutions***
- ***Process for evaluation of proposed solutions***
- ***Identification of potential impact on competitive markets***
- ***Consideration of non-transmission solutions –as appropriate***
- ***Cost allocation methodology***
- ***Specification of appropriate roles for NYPSC/NYDPS & NYISO***

INTERREGIONAL PLANNING
&
Cost Allocation

Order 1000: Planning

- **Each transmission provider must develop further procedures with each of its neighboring regions within its Interconnection**
  - ***Final Rule identifies a number of specific requirements, including:***
    - **Data sharing on a regular basis—at least annually**
    - **Sharing of information on regional needs and potential solutions**
    - **A formal procedure for the "identification and joint evaluation of interregional facilities that may be more efficient or cost –effective solutions to regional needs"**
    - **Transparency – post information on a website**
- **Separate inter-regional planning agreements are not required**
    - **An inter-regional "plan" is not required**
- **Multilateral or interconnection-wide planning is encouraged — but not required**
- **An inter-regional stakeholder process is encouraged**
- **Jurisdictional entities to attempt to develop interregional coordination procedures with neighbors in another country**

Order 1000: Cost Allocation

General Requirements

- **Transmission providers in each pair of neighboring regions to develop a mutually agreeable cost allocation methodology for a transmission facility located in both regions for inclusion in each region's tariff**
- **Multi-lateral cost allocation is encouraged—but not required**
- **Final Rule does not propose a uniform methodology**
  - **Must comply with FERC's six cost allocation principles**
  - **Interregional cost allocation methodology may be different from the respective regional methodologies**
  - **Cost allocation for a region's share of an interregional facility may differ from the cost allocation for a regional facility**
- **Final Rule does not address cost recovery**
- **If region(-s) cannot agree, FERC will decide**
- **Principles do not prohibit voluntary participant funding**
  - ***Participant funding is not acceptable for compliance***

Order 1000: Compliance Framework

- ***The Northeast ISO/RTO Planning Coordination Protocol already meets many of the Inter-regional Planning requirements of the Final Rule***
  - **Some modifications/clarifications will be needed**
  - **Revisions to individual tariffs may also be needed**
- ***There is an active stakeholder process established under the Protocol ("IPSAC")***
- ***ISO-NE, NYISO & PJM have been meeting with their stakeholders on these issues since Spring 2013***
- ***Canadian neighbors are already participants in inter-regional planning activities in the Northeast***
- ***DOE-ARRA funded inter-connection wide planning efforts are encouraged by FERC***
  - **ISO-NE, NYISO and PJM are sponsors and active participants in EIPC**

13

Next Steps

In consultation with regional stakeholders:

- **Determine modifications to Northeast Protocol**
  - *Inter-regional planning process specificity/clarifications*
  - *Coordination with Regional Planning cycles*
  - *Conforming language to Order 1000 terminology*
  - *How to address public policy considerations*
- **Determine modifications to individual tariffs**
- **Develop an Inter-regional Cost Allocation Methodolgy**
  - *Determine feasibility of a "multi-lateral" methodology*
  - *Strive for "simplicity" to the extent feasible*
  - *Compatibility with regional cost-allocation methods*
- **Logistical Issues**
  - Establish linkages to regional planning processes
  - Determine the appropriate mechanism for compliance filing

NEW YORK INDEPENDENT SYSTEM OPERATOR

The New York Independent System Operator (NYISO) is a not-for-profit corporation that began operations in 1999. The NYISO operates New York's bulk electricity grid, administers the state's wholesale electricity markets, and provides comprehensive reliability planning for the state's bulk electricity system.

www.nyiso.com

NOVEMBER 27, 2012 | MONTREAL, QUÉBEC, CANADA



Regional Planning Update

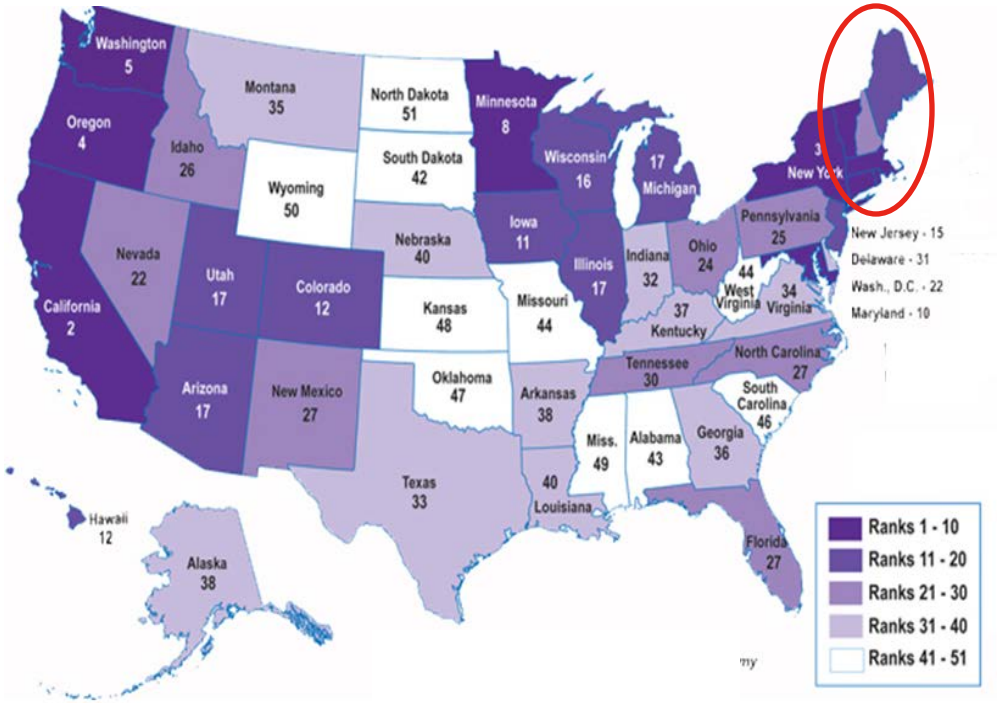
NPCC Governmental/Regulatory Affairs Advisory Group

Anne George

VICE PRESIDENT, EXTERNAL AFFAIRS & CORPORATE COMMUNICATIONS

FORECASTING AND ENERGY EFFICIENCY

Energy Efficiency (EE) Priority for New England



- Ranking of state EE efforts by the *American Council for an Energy-Efficient Economy*:
  - Massachusetts 1
  - Rhode Island 5
  - Vermont 5
  - Connecticut 8
  - Maine 12
  - New Hampshire 21

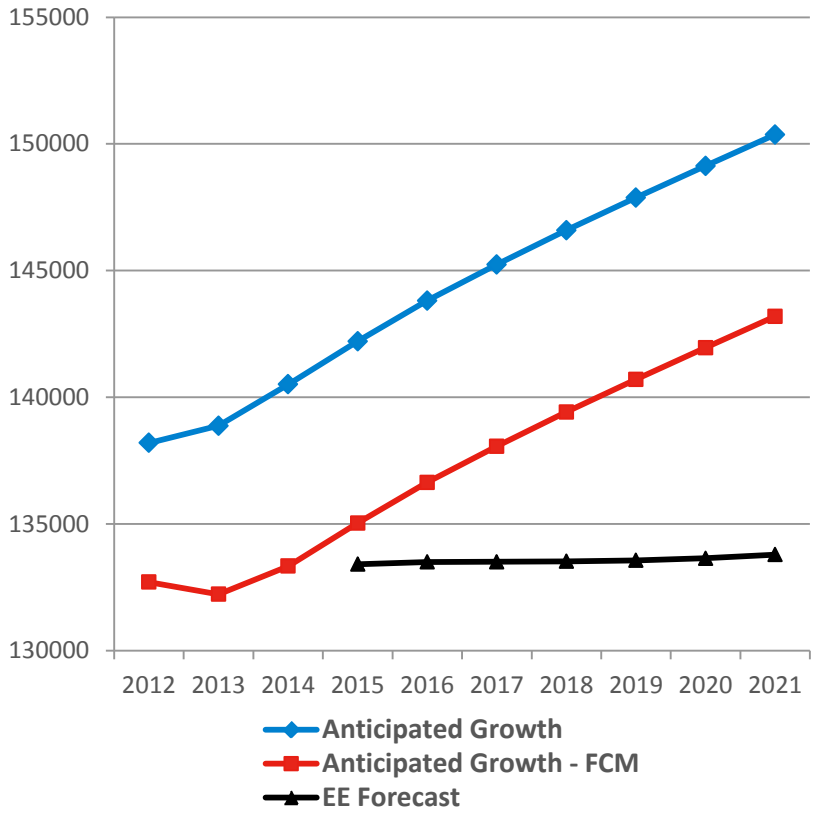
- Billions spent over past few years in the region; more on horizon
  - Approximately $1 billion invested from 2008 to 2010
  - ISO estimates $5.7 billion to be invested in EE from 2015 to 2021

Incorporating Impact of Energy Efficiency

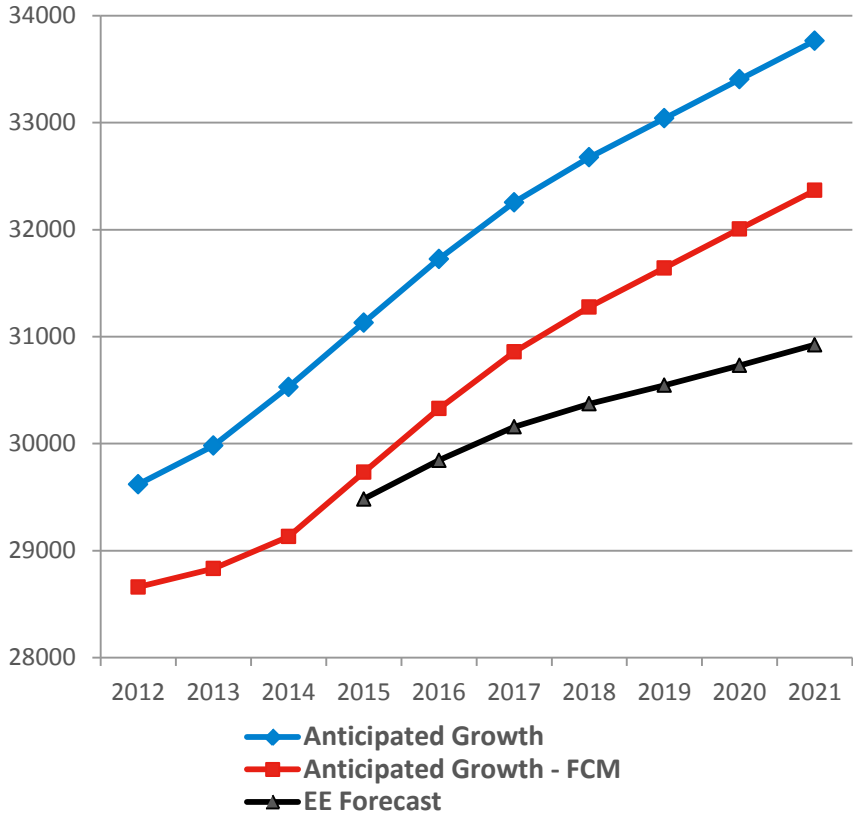
- Given the expectation of large future investment in EE in New England, the ISO worked with the region's stakeholders to identify characteristics of utility-based EE programs in the region that may be useful for forecasting future EE impacts
- The ISO developed a forecast of EE savings across a 10-year planning horizon
  - The forecast projects long-term reductions in peak demand and energy as a function of projected EE spending and historical costs
  - First in the nation multistate energy-efficiency forecast

Forecasted Impacts of Energy Efficiency

Energy Demand (GWh)



Peak Load (MW)



Impact of EE Forecast on Transmission Planning

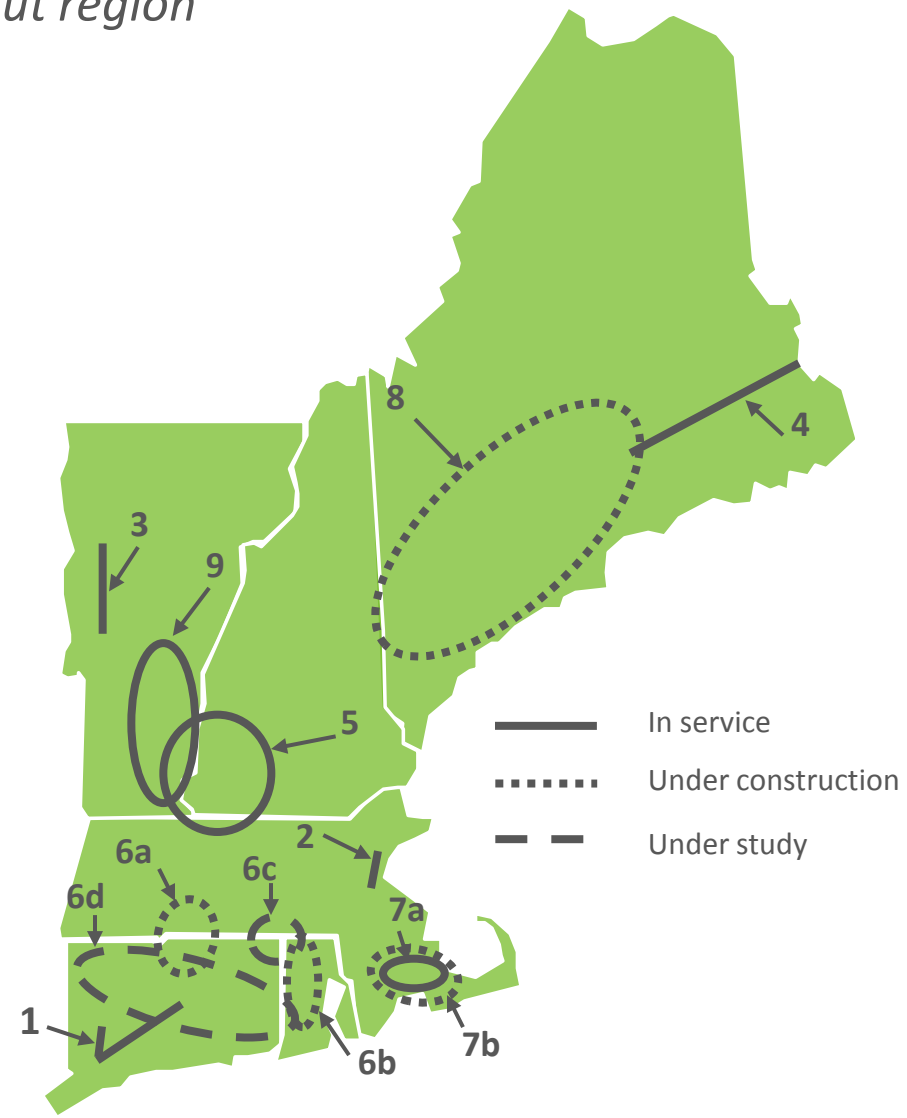
- The first EE forecast, which was recently completed, required dozens of stakeholder meetings and three years to finalize
  - This forecasts revealed that about $260 million in transmission expenses have already been deferred for New England customers as a result of EE investment and grid improvements
  - Forecast incorporated extraordinary amount of data
- Process updated annually
  - Next forecast to be finalized early 2013

TRANSMISSION AND GENERATION

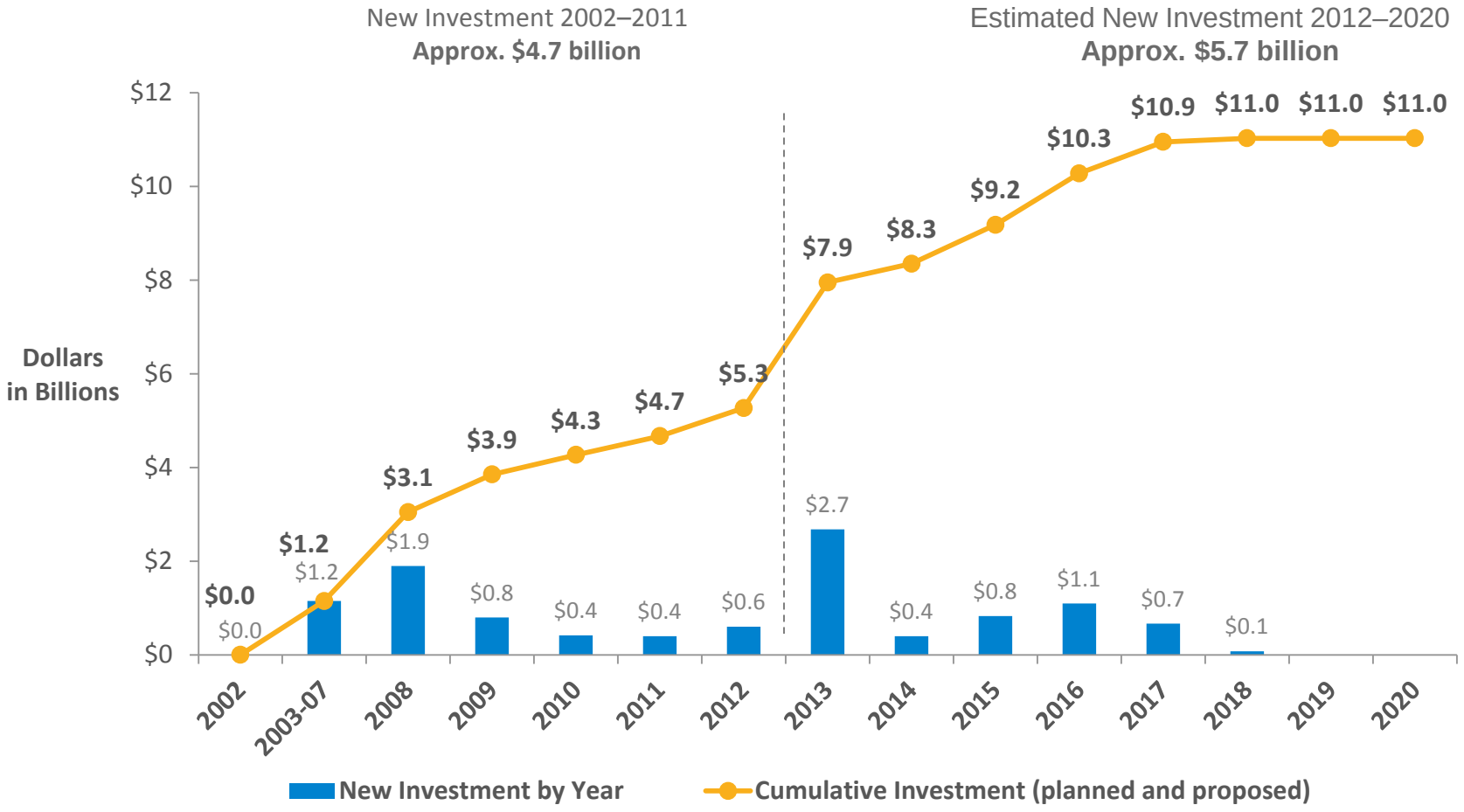
Projects to Maintain Reliability are Progressing

Transmission projects planned throughout region

1. Southwest CT Phases I & II
2. NSTAR 345 kV Project, Phases I & II
3. Northwest Vermont
4. Northeast Reliability Interconnect
5. Monadnock Area
6. New England East-West Solution
   a. Greater Springfield Reliability Project
   b. Greater Rhode Island Reliability Project
   c. Interstate Reliability Project
   d. Greater Hartford/Central Connecticut
7. Southeast Massachusetts
   a. Short-term upgrades
   b. Long-term Lower SEMA Project
8. Maine Power Reliability Program
9. Vermont Southern Loop



Transmission Investment in New England

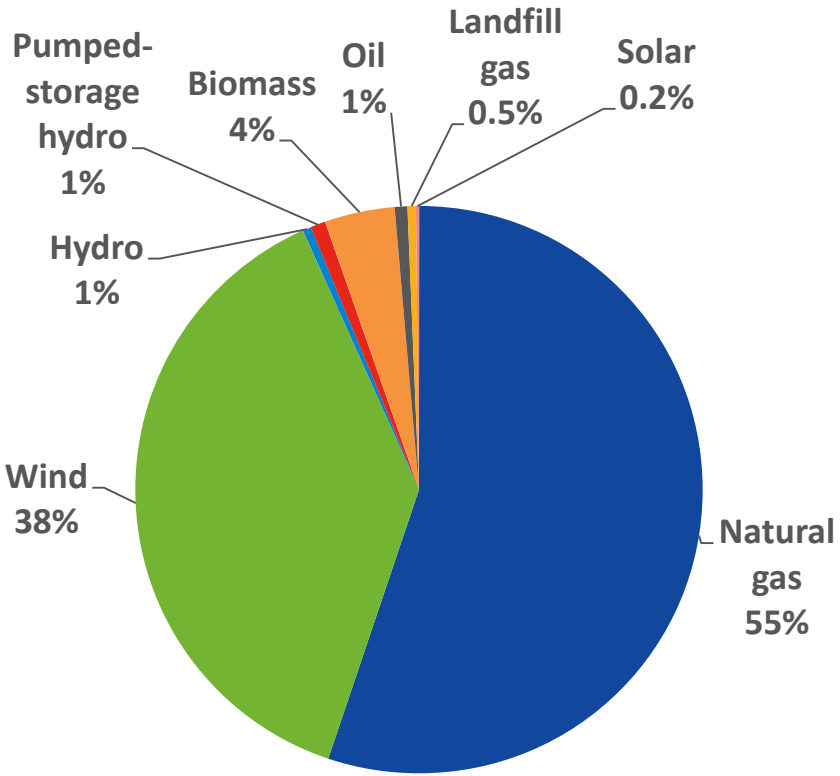


Source: ISO New England Transmission Project List, through October2012 Update.

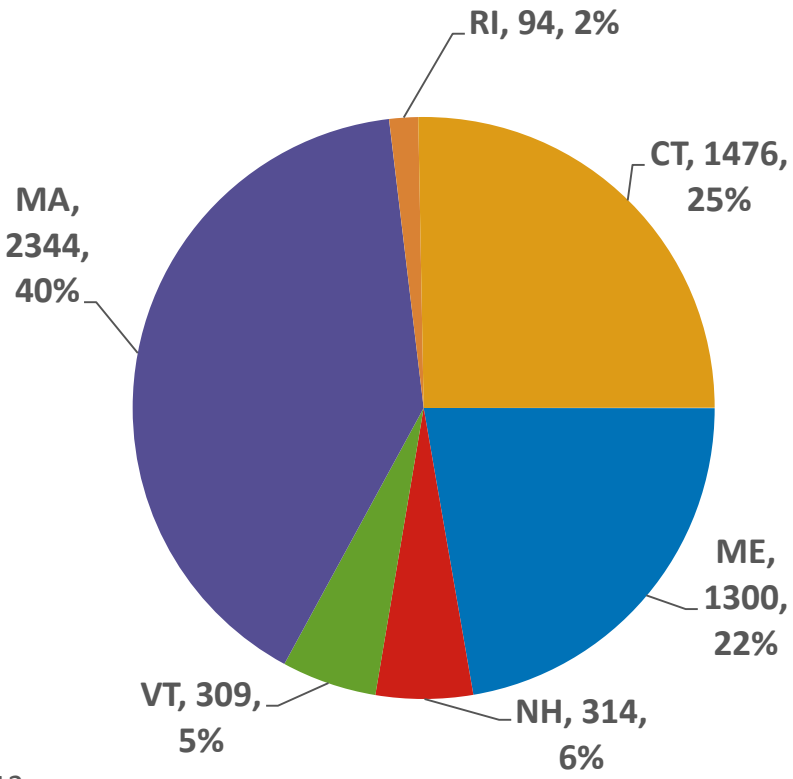
Generator Proposals in the ISO Queue

Approximately 6,000 MW

By Type



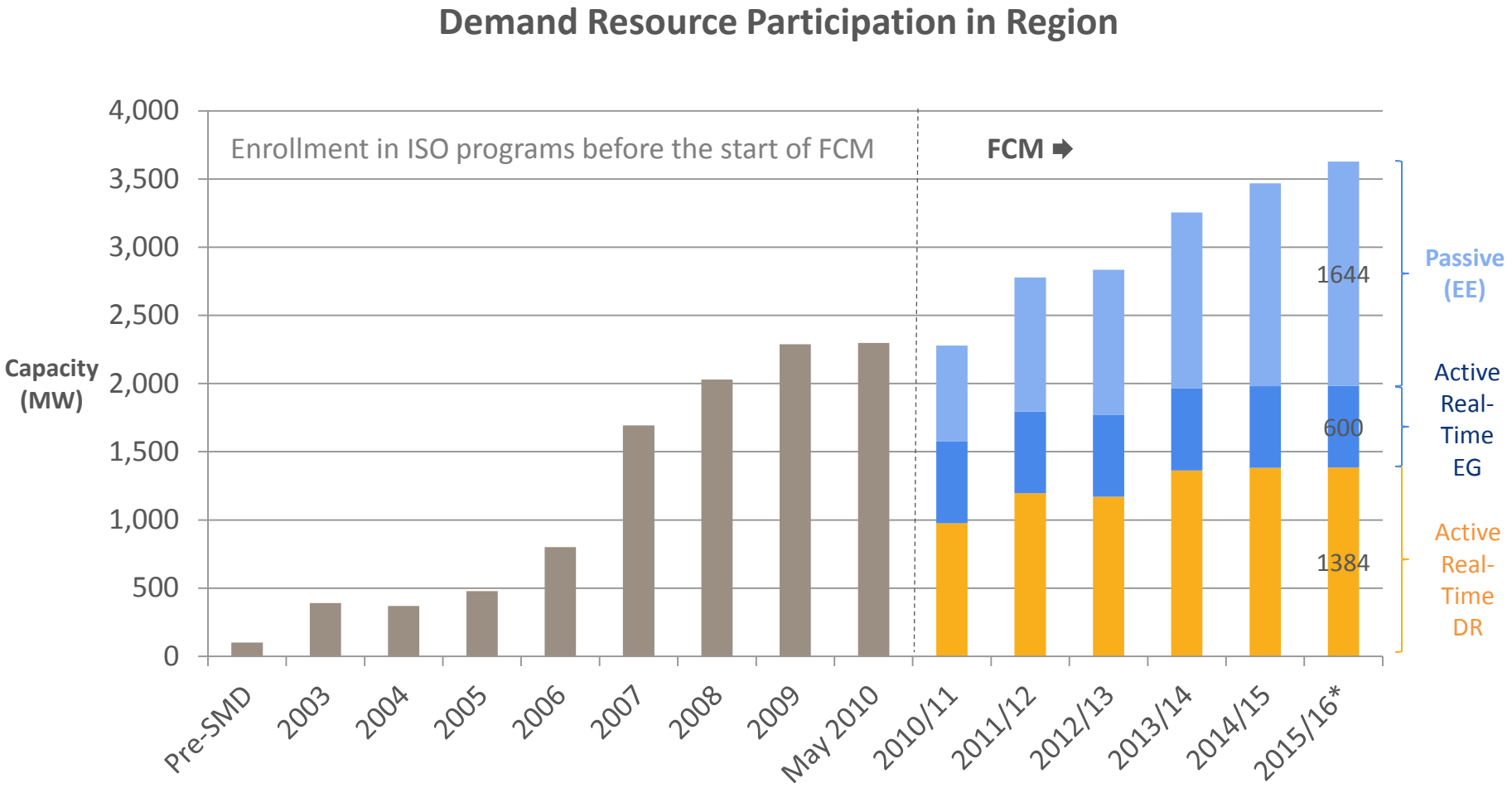
By State



Summer 2012

Demand Resources Growing in New England

Capacity Market has stimulated DR growth

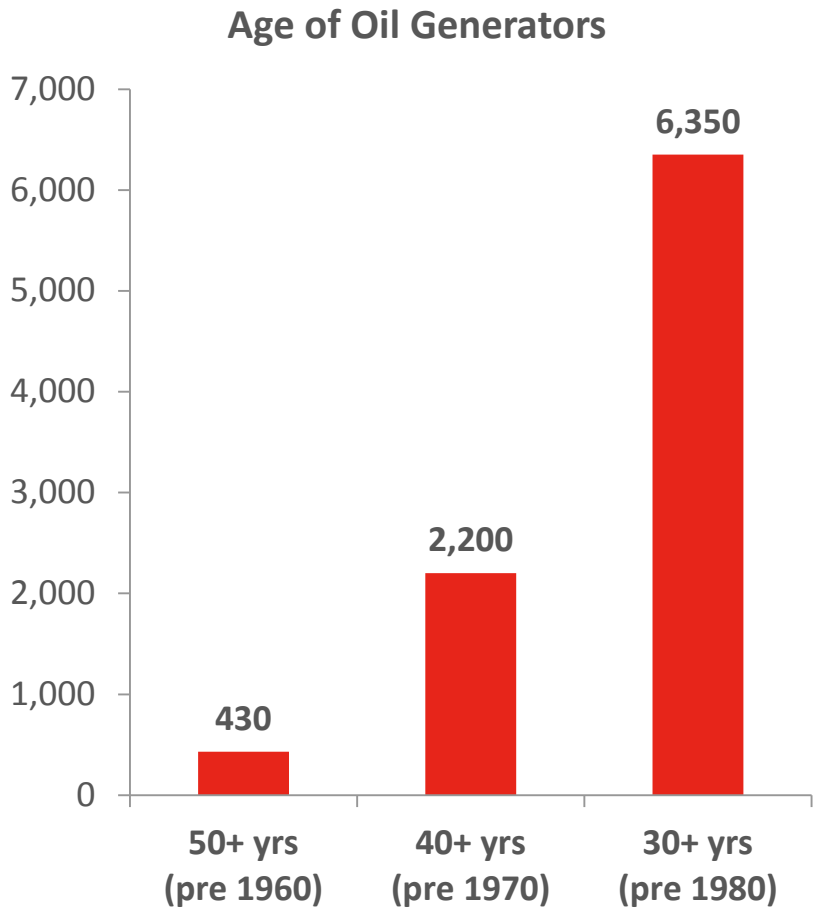


2010/11–2014/16: Total DR cleared in FCAs #1 – #6; real-time emergency generation capped at 600 MW

CHALLENGES FOR REGION

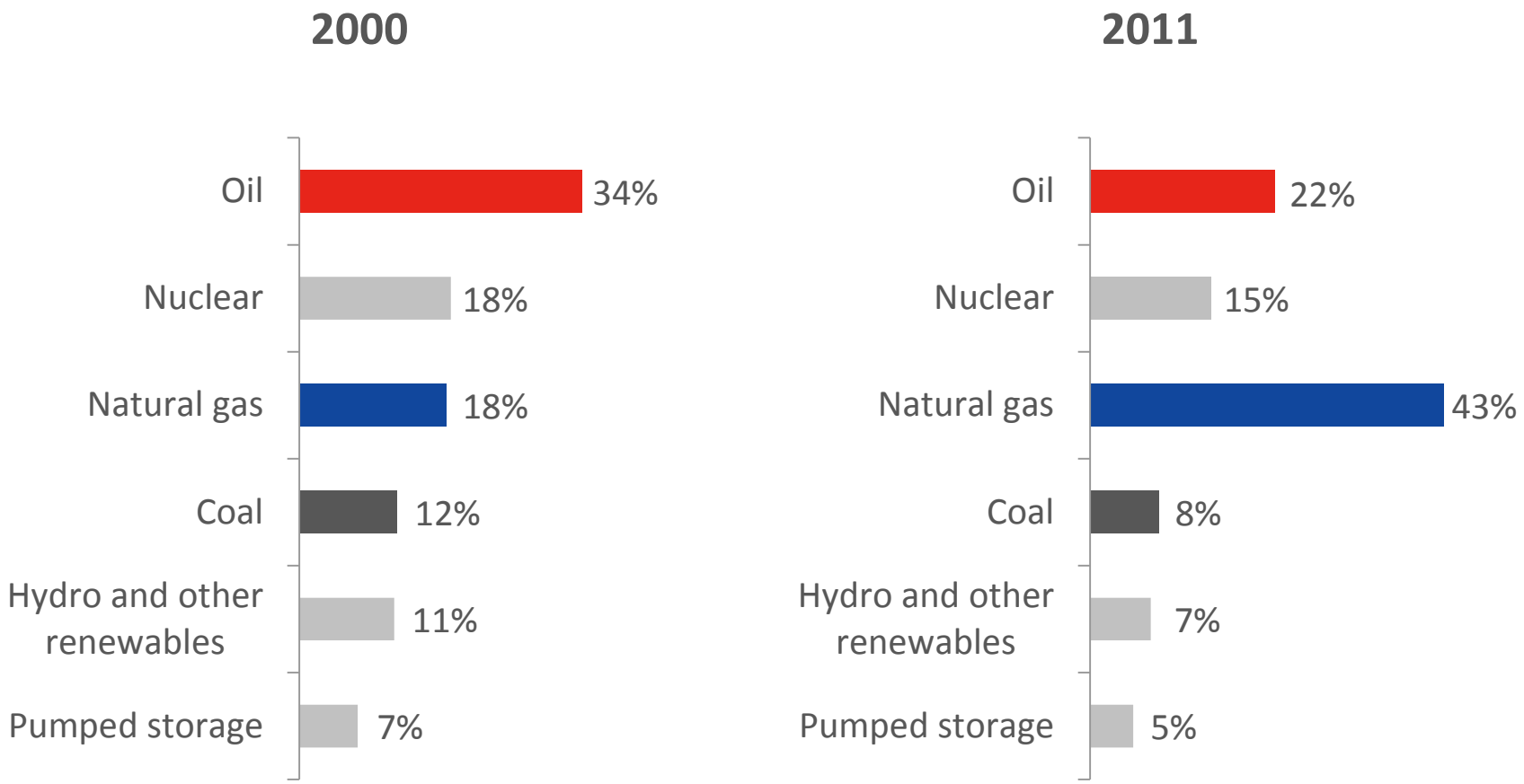
Challenges Facing the Region

- Reliance on natural gas and fuel supply for generators
- Long-term concerns with retaining resources and developing new ones
- Economic factors and environmental regulations will likely result in the retirement of older coal and oil generating units



Regional *Capacity* has Shifted from Oil to Natural Gas

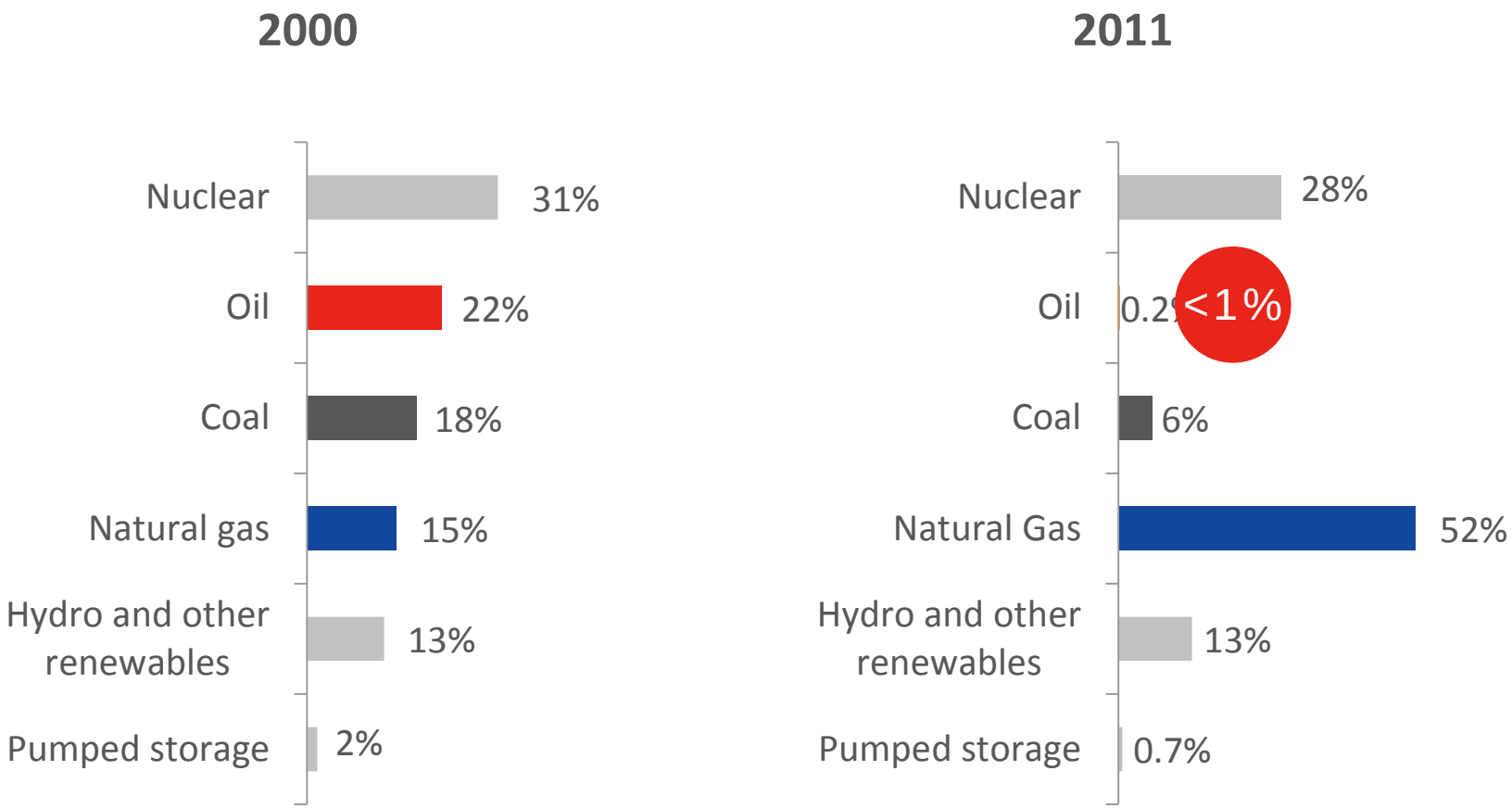
Percent of Total System Capacity



Other renewables include landfill gas, biomass, other biomass gas, wind, solar, municipal solid waste, and misc. fuels.

Regional *Energy* has Shifted from Oil to Natural Gas

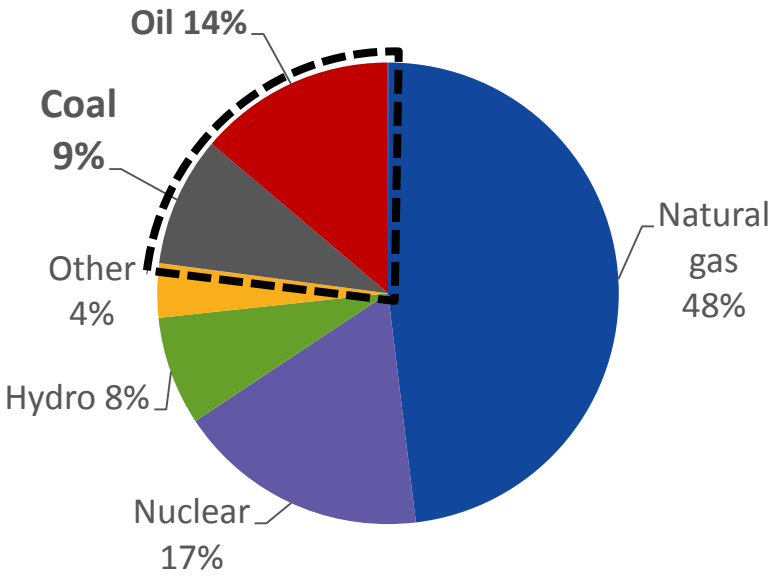
Percent of Total Electric Energy Production



Other renewables include landfill gas, biomass, other biomass gas, wind, solar, municipal solid waste, and misc. fuels.

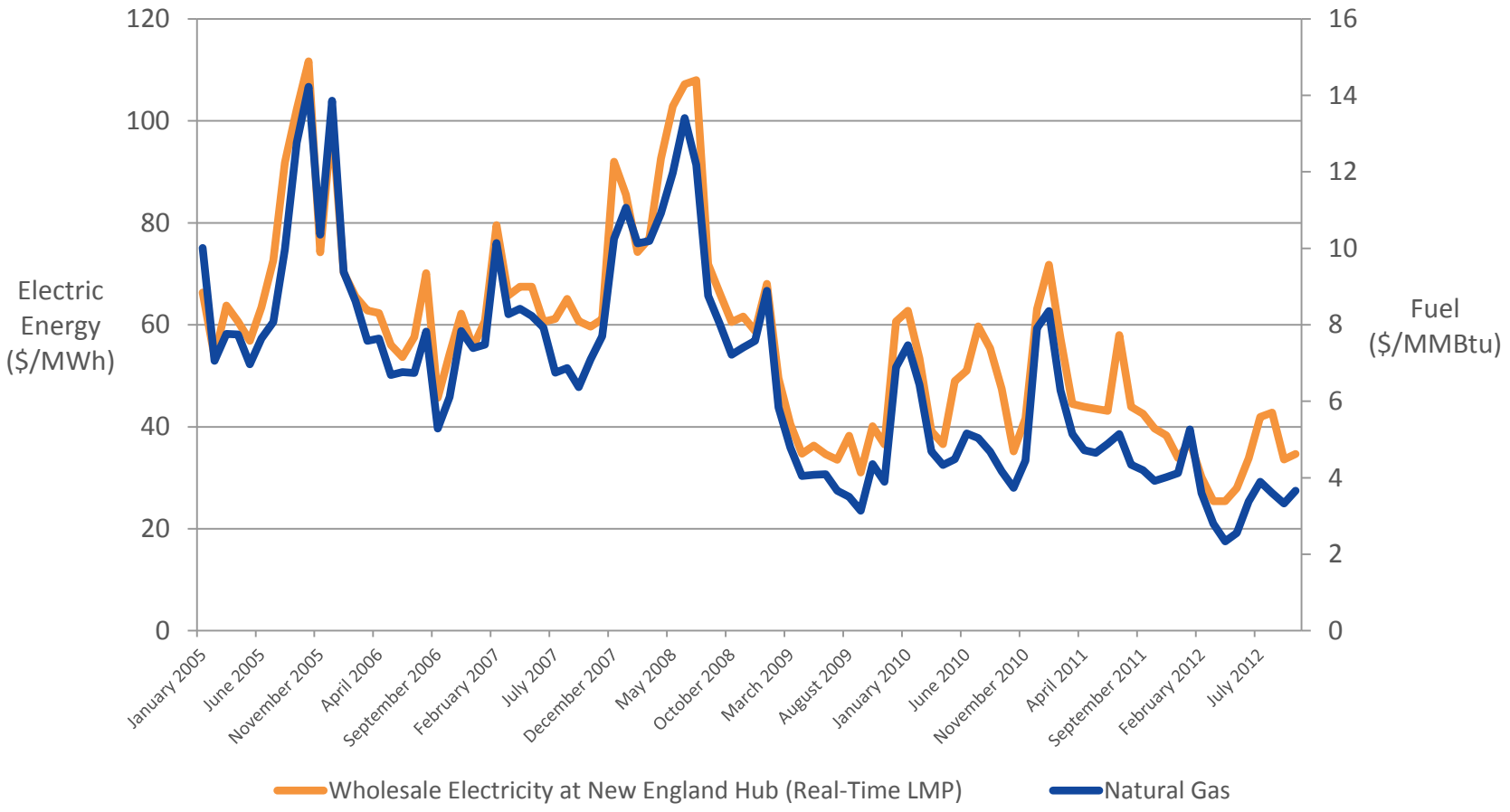
Oil and Coal Resources are Still Needed

Peak Day
July 22, 2011



- Coal- and oil-fired resources supplied nearly **25%** of energy during the 2011 system peak
- But challenges remain for system operators
  - Oil-fired generators are reducing oil inventory due to high fuel costs and infrequent operation
  - Resources have long start-up times and take even longer to come online reliably after extended periods offline

Reliance on Gas Has Resulted in Low Energy Prices



Power Plant Emissions have Declined with Changes in the Fuel Mix

Reduction in Aggregate Emissions (ktons/yr)

Year	NO_x	SO_2	CO_2
2001	59.73	200.01	52,991
2009	27.55	76.85	49,380
% Reduction, 2001–2009	**⬇ 54%**	**⬇ 62%**	**⬇ 7%**

Source: Calculated Annual Emissions of NO_x, SO_2, and CO_2 for 2001 to 2009 (ktons/yr), RSP11.

Reduction in Average Emission Rates (lb/MWh)

Year	NO_x	SO_2	CO_2
2001	1.36	4.52	1,009
2009	0.46	1.29	828
% Reduction, 2001–2009	**⬇ 66%**	**⬇ 71%**	**⬇ 18%**

Source: Annual Average Calculated NO_x, SO_2, and CO_2 Emissions Rates, 2001 to 2009 (lb/MWh), RSP11.

STRATEGIC PLANNING INITIATIVE

Dependence on Natural Gas is *Highest-Priority* Strategic Risks

SPI
STRATEGIC PLANNING INITIATIVE

Five Strategic Risks Identified:

- Increased Reliance on Natural Gas-Fired Capacity
- Resource Performance and Flexibility
- Retirement of Generators
- Integration of a Greater Level of Variable Resources
- Alignment of Markets with Planning

Strategic Planning Initiative

Continuing analysis underway to inform solutions process

Completed studies/reports

- ✓ ***Roadmap for New England***
  (March 2012)
- ✓ ***Forward Capacity Market Redesign Whitepaper, "FCM 2.0"***
  (May 2012)
- ✓ ***Aligning Markets and Planning, ISO Discussion Paper***
  (June 2012)
- ✓ ***Natural Gas Study; phase one***
  (June 2012)
- ✓ ***Addressing Natural Gas Dependence Whitepaper***
  (July 2012)
- ✓ ***FCM Paper: Core Capacity Product Definition and Performance Incentives/Consequences***
  (October 2012)

Ongoing studies/reports (2012)

- ❑ ***Natural Gas Study; phase two***
  Scope presented to PAC September 20
- ❑ ***Strategic Transmission Analysis: Generator Retirements***
  Next presentation to PAC in December 2012
- ❑ ***Strategic Transmission Analysis: Wind expansion***
  Presentation to PAC in December 2012

Strategic Planning Initiative analysis posted on ISO website:
www.iso-ne.com/spi

Interregional Gas/Electric Study Status Update

by
John P. Buechler
NYISO Executive Regulatory Policy Advisor

NPCC Governmental/Regulatory Affairs Advisory Group
November 27, 2012
Montreal, Canada

Overview

- **Previous Gas/Electric Studies**
- **Current Interregional Initiative**
  - *Study Participants*
  - *Study Region*
  - *Statement of Need*
  - *National Context*
  - *Primary Objectives*
- **Current Status**

Previous Gas/Electric Studies

- Northeast ISO/RTOs have performed previous gas/electric coordination studies on both a regional and inter-regional basis
- Last interregional study was in 2003
  - *NYISO, Ontario, ISO-NE, PJM and NERC*
- More recently separate regional studies have been conducted
  - *NYISO – 2009*
  - *ISO-NE – 2011 Study; 2012 White Paper*
  - *PJM - 2005*

Study Participants

- Study participants are:
  - *ISO-New England*
  - *Midwest ISO*
  - *New York Independent System Operator*
  - *Ontario's Independent Electricity System Operator*
  - *PJM Interconnection*
  - *TVA*

Study Region

- The Study Region shall consist of:
  - *The ISO-New England, Midwest ISO, New York ISO, Ontario's Independent Electricity System Operator , PJM Interconnection and the TVA Areas, both collectively and individually as appropriate*
  - *Includes analysis of the major pipelines and storage systems, electric systems, and local gas distribution systems (LDCs) serving the Study Region*

Statement of Need

Interdependence of the nation's electric and natural gas industries is an issue that is growing in importance:

- *Significant increased reliance on natural gas as the primary fuel for generating electricity raises concerns for maintaining electric reliability*
- *Future adequacy of the natural gas infrastructure (including the aging of that infrastructure) to meet the coincidental requirements of gas utilities and generators*
- *The abundance of new gas supply is being driven in part by massive discoveries of natural gas in deep shale formations near Northeastern U.S. load centers*

National Context

This study is designed to accomplish:

- *First of its kind operational and planning level joint study reflecting new environmental policies, the impact of shale gas on markets and operations, and escalating dependence on gas-fired electric generation over a broad interregional area*

- **Will provide study participants, as well as federal and state policy makers and regulators with:**
  - *Current and future security and adequacy data for the gas and electric systems*
  - *Insight into key operational, infrastructure and market interdependencies between gas and electric systems*
  - *Insights into the interplay of storage, pipeline and shale gas development, and dual fuel capability on the electric system*
  - *A unique perspective on regional/interregional operational and planning challenges*

Primary Objectives

- Phase 1
  - **Objective 1:** *Develop a baseline of the electric & gas systems, including their planning & interactions*
  - **Objective 2***:* *Evaluate the adequacy of the gas pipeline system to supply electric generation needs over a 10-year horizon*
- Phase 2
  - **Objective 3:** *Review the benefits and costs of dual fuel capability compared with securing firm gas transportation*
  - **Objective 4:** *Identify contingencies on the natural gas system that could adversely affect the electric system—and vice versa*

Current Status

- *RFP had been developed and bids were solicited for a smaller Northeast Study Region*
- *MISO and TVA subsequently expressed an interest in participating in the study*
- *Evaluation of proposals for original RFP has been placed on hold*
- *Study scope being expanded to incorporate MISO and TVA areas*
- *Participants are exploring funding sources*
- *Updated RFP anticipated by end of 2012*

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2012 Long-Term Reliability Assessment

Preliminary Highlights

John Moura, Associate Director, Reliability Assessment
NERC Staff

RELIABILITY | ACCOUNTABILITY

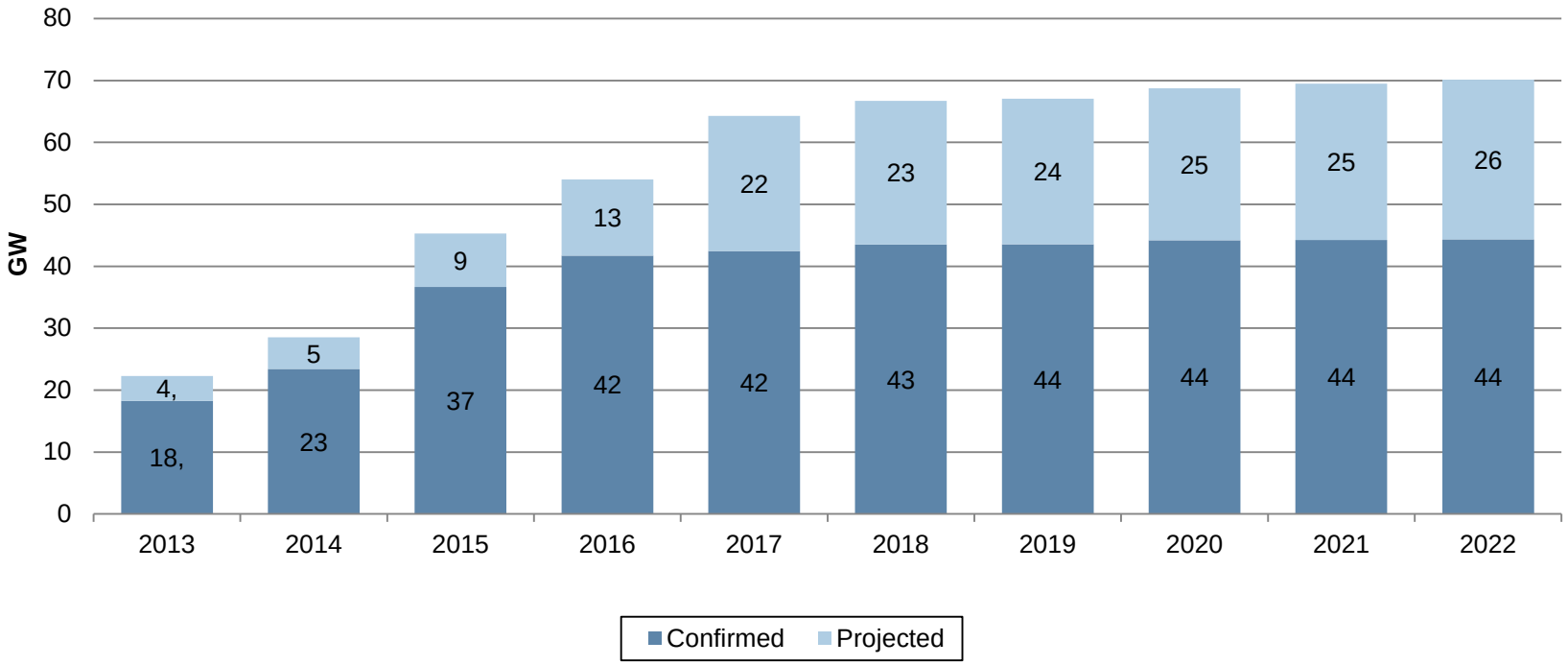





Key Finding: Fossil-Fired Generation Retirements

Unprecedented Fossil-Fired Generation Retirements

- Cumulative retirements between 2012 and 2022
- Slightly larger impacts than our 2011 generator retirement study

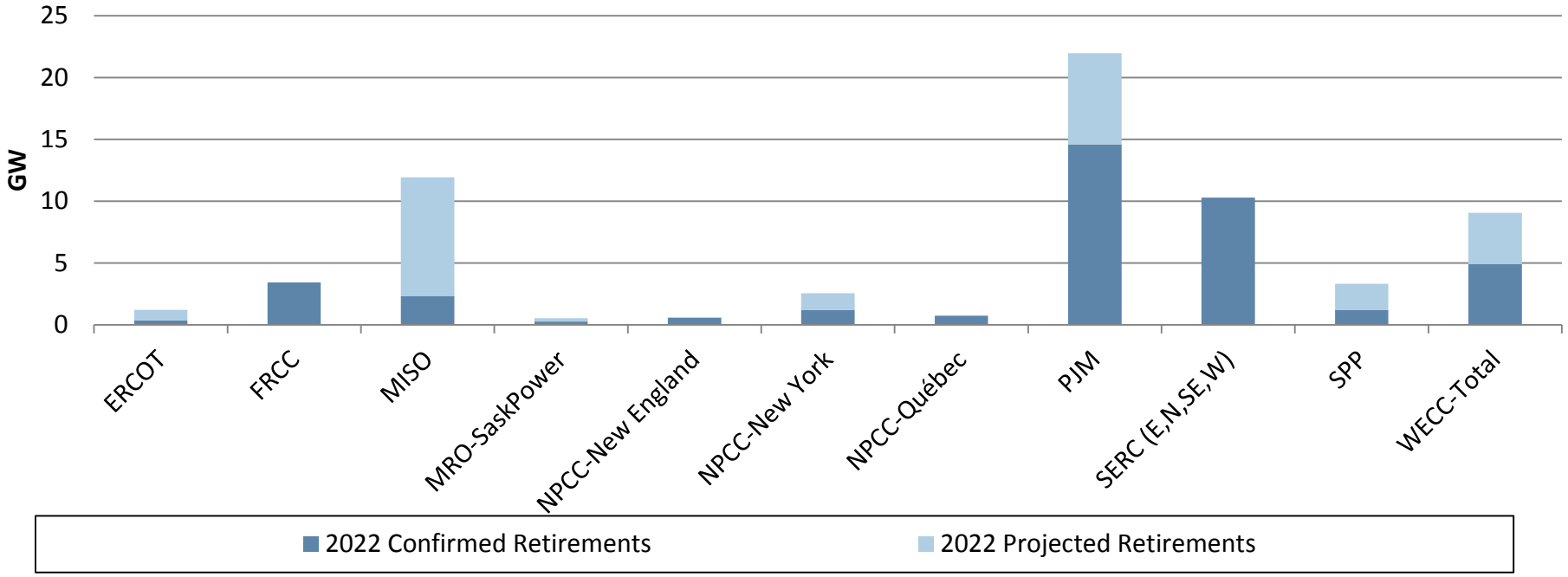


Preliminary Data

Key Finding: Fossil-Fired Generation Retirements

Unprecedented Fossil-Fired Generation Retirements

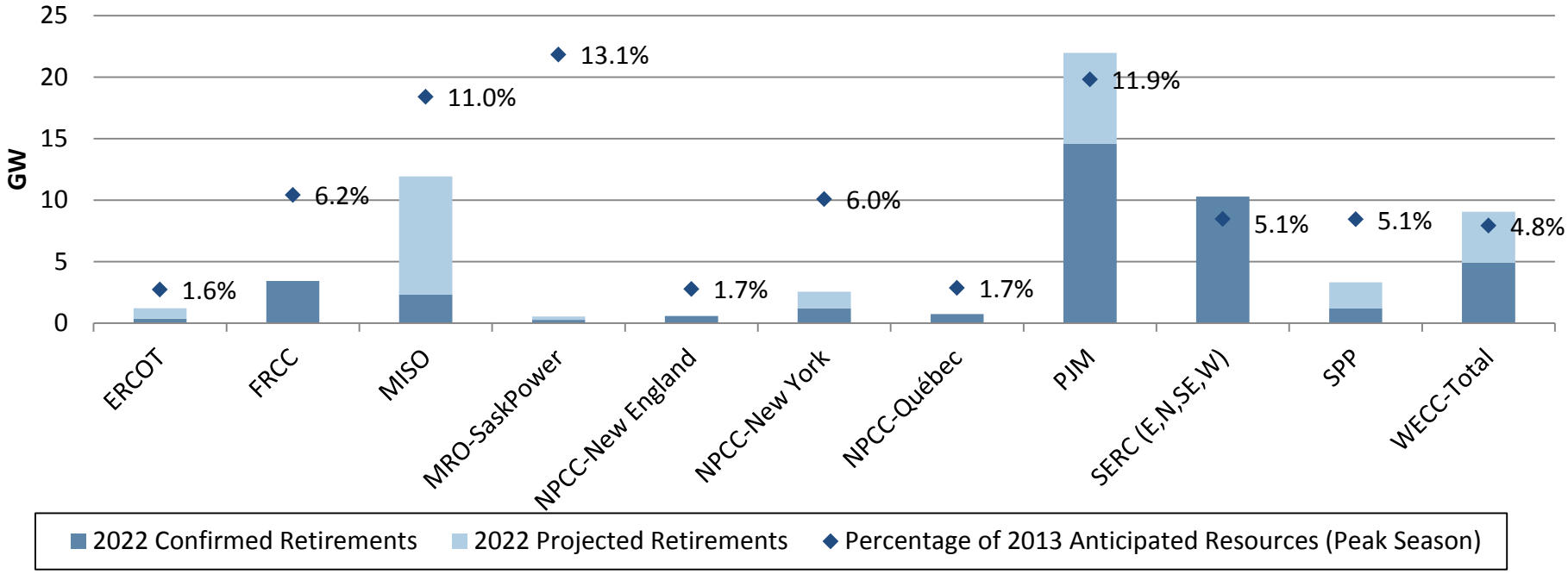
- Assessment Area view reveals high-impact regions



Key Finding: Fossil-Fired Generation Retirements

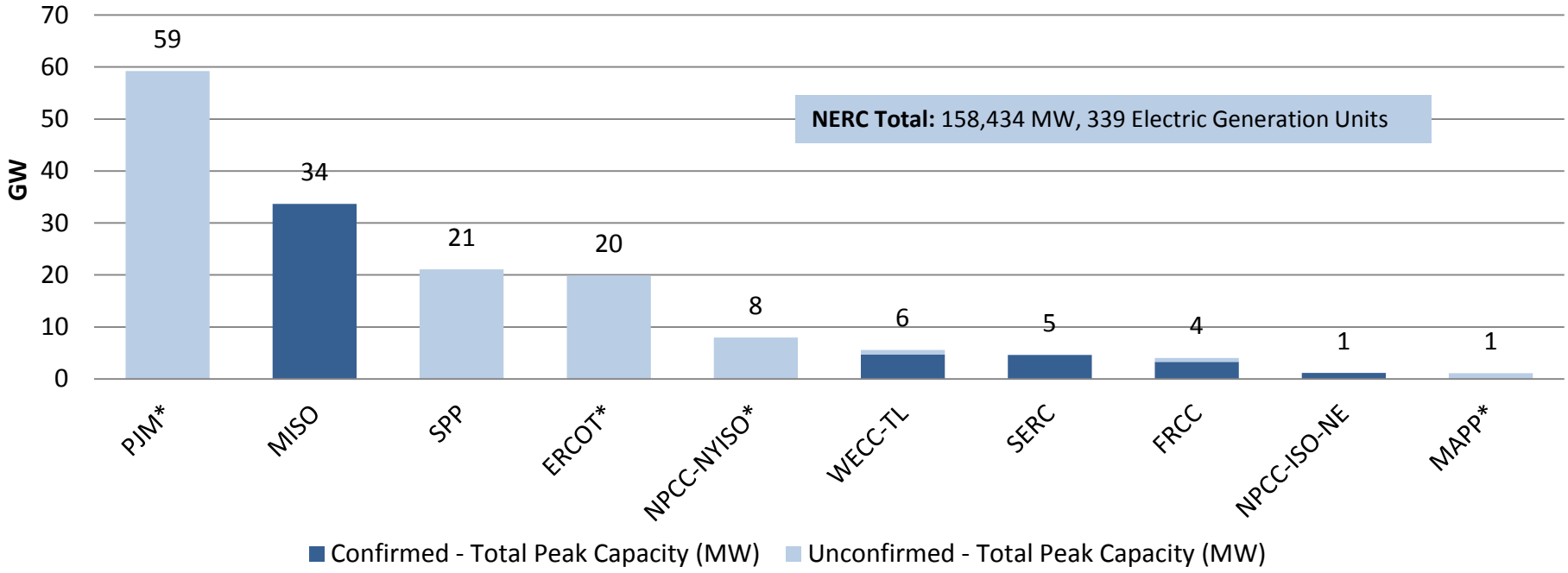
Unprecedented Fossil-Fired Generation Retirements

- Assessment Area view reveals high-impact regions
- MISO, MRO-SaskPower, PJM projected to retire over 10% of all capacity resources



Key Finding: Generation Retrofits

Long-Term Generator Maintenance Outages for Environmental Retrofits Can Impact Off-Peak Reliability



Note: Unconfirmed retrofit outages include projections of 316(b) of the Clean Water Act compliance activities

NERC
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Questions?

RELIABILITY | ACCOUNTABILITY






Québec Interconnection Approach to BES



Sylvain Clermont

November 27, 2012

Hydro Québec TransÉnergie

Introduction: HQT

- **Our mission**
  HQT operates its transmission system, markets system capacity and manages power flows across Québec. Our *Direction Contrôle des mouvements d'énergie (*System Control) acts as the Reliability Coordinator (RC) for transmission systems in Québec
- **Our facilities**
  Our system, the most extensive transmission system in North America, comprises 33,630 km (20,897 miles) of line and 514 substations as well as interconnections allowing power interchanges with grids in the Maritime provinces, Ontario and the U.S. northeast
- **Our activities**
  HQT owns and operates more than 95% of the transmission capacity in Québec. HQT is registered at NERC as TO, PA, TP, TSP, RC, BA, TOP and IA

One entity with direct control and full awareness of the whole Québec Interconnection

System characteristics: reliability of the Québec Interconnection

- HQT is firmly committed to system reliability, has invested in major reliability initiatives and has learned from past blackouts
- **The characteristics** of the HQT system must be considered in system design and operation to ensure a high level of reliability
  - Remote hydroelectric generation -> Criteria met without congestion
  - Strongly winter peaking -> Worst case scenario for planning
  - Strong transmission backbone -> Clear "bright line" demarcation
  - Local transmission subsystems -> Criteria to ensure reliability
  - Asynchronous with the Eastern Interconnection -> Control of the whole Interconnection

HQT faces a combination of unique characteristics that motivates an approach to reliability different from other Interconnections

Québec system design and operation

- Because of its characteristics, HQT's BULK power system must *exceed* NPCC and NERC criteria and standards (for certain aspects) to ensure transmission backbone reliability:
  - Robustness to withstand design contingencies without use of Special Protection Systems (SPS) or loss of load
  - Performance requirements for certain extreme contingencies

Impacts of the new BES definition on the Québec Interconnection

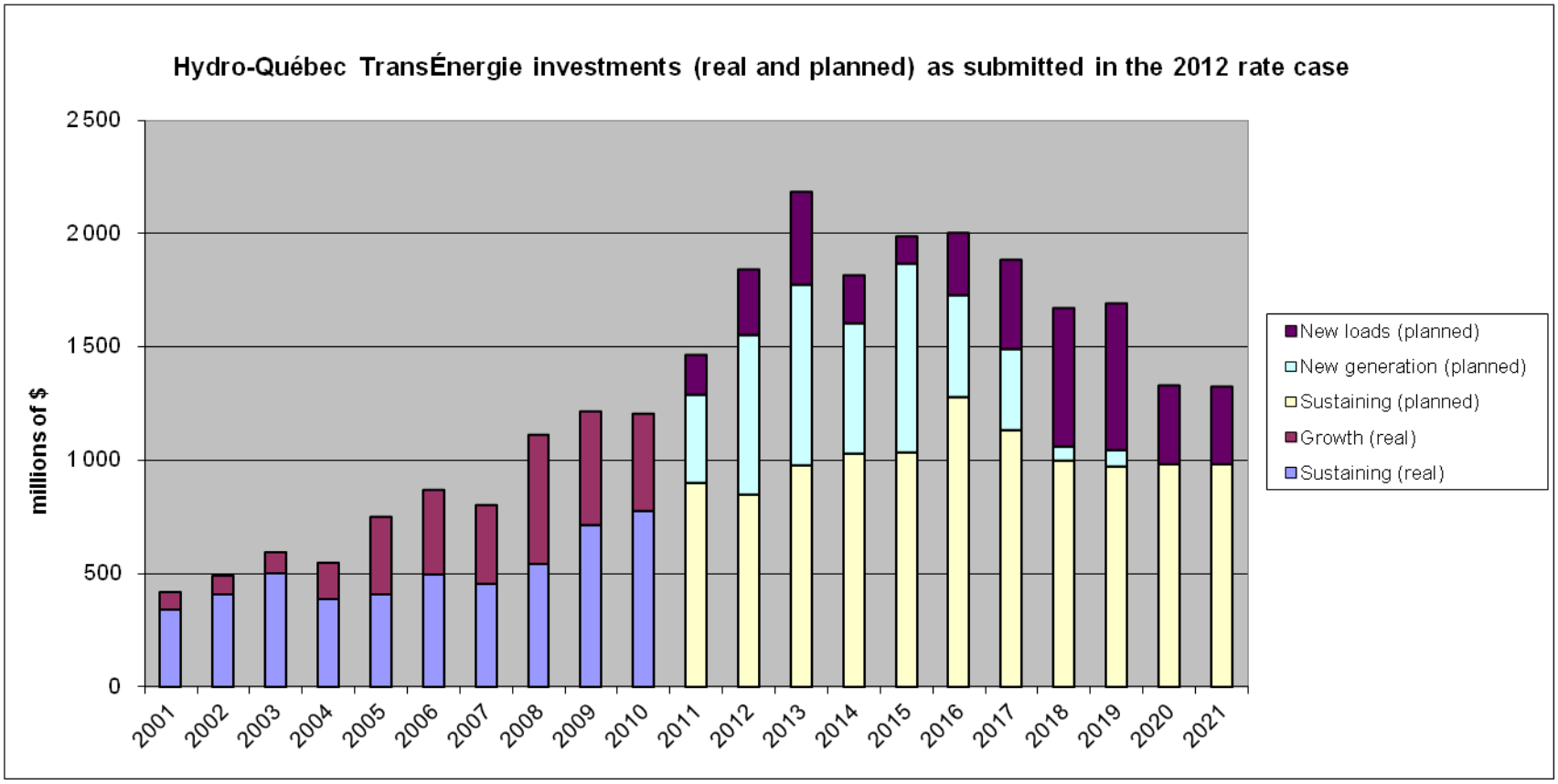
- The new BES definition filed with FERC includes transmission elements operated at 100 kV or higher
- Of the 474 substations that are part of our local transmission subsystems, a majority would be included in the BES
- **No measurable impact on bulk power system reliability;** however, increased burden for the RC and TOP
- Subsystem transmission projects would be required to comply with TPL-003-1a:
  - SPS additions
  - New lines, breaker additions to existing substations, etc.
- Many of the subsystem SPS additions would have no impact on service continuity

Quick cost estimate for these projects: > $850 million

Investments in reliability

- Demanding reliability objectives combined with the system's unique technical characteristics meant major investments over the years. For example:
  - Adoption of criteria in the late 80's triggered a $1.3-billion reinforcement project ($2-billion current)
    - Addition of series compensation on the 735-kV grid
    - Commissioning of key SPSs
  - Adoption of a new voltage sensitivity criterion and the need for increased transfer capability triggered a $250-million project in 2008
    - Addition of series compensation and SVC's at two 735-kV substations

Investments on HQT's network (in millions of $)



8 000	19 000

27 000

Reliability framework in Québec

- The *Régie de l'énergie du Québec (Québec Energy Board)* has exclusive jurisdiction over the entities and the framework of the Québec Interconnection and:
  - Has designated HQT's *Direction Contrôle des mouvements d'énergie* as the Reliability Coordinator (RC) for the Québec control area
  - Adopts reliability standards filed by the RC
  - Approves the Register identifying entities subject to reliability standards
  - Monitors and enforces compliance
  - Has the power to levy important fines
  - Has put in place consultation mechanisms in which NERC and NPCC can participate
- The *Régie de l'énergie* signed MOUs with NERC and NPCC to assist in these functions

Reliability framework in Québec: tiered approach to application of standards - definitions

- Bulk power system (BPS)
  - Mainly 735-kV and 450-kV DC substations with their connecting lines and transformers
  - All interties with the US included in BPS
- Main transmission system (RTP)
  - BPS facilities and some LTS (including generation assets above 50 MVA)
  - Facilities required for generation/load balancing, frequency reserve, voltage control, interchange transactions, etc.
  - The RC has full control and visualization over RTP
- Local transmission subsystems (LTS)
  - Operate at lower voltage levels and are connected to 735-kV substations
  - Feed industrial clients and load substations and connect local generation and some interconnections

Reliability framework in Québec: a tiered approach to application of standards

- BPS
  - All standards adopted by the *Régie de l'énergie* applied
- RTP (BPS and some LTS)
  - Most standards applied, excluding TPL and some PRC standards
- LTS
  - Standards such as TPL-001 and TPL-002 applied
  - Generator (50 MVA and more) requirements applied

Reliability framework in Québec: Québec's approach

- An approach customized for global reliability of the HQT system considering its special characteristics
- Tiered approach to application of standards
- Monitoring of compliance based on that approach
- Approach filed by the RC and acknowledged, but not yet approved, by the *Régie de l'énergie*

Questions? Comments?

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Final Regional Entity Responses to NERC June 5, 2012 Letter on Follow-Up Actions Related to September 8, 2011 Outage Recommendations

Report on Opportunities for Improvements

Group A: Next-Day and Real-Time Operating Issues

Recommendations 1 – 4 address the responsibilities of RCs, TOPs, and BAs in the next-day planning timeframe. They stress the importance of accuracy in next-day planning models, including sharing, across the entire RC footprint, generation and transmission outages and transactions that could impact the reliability of the bulk power system (BPS); comprehensiveness of studies with respect to facilities that can impact bulk power system reliability, including sub-100 kV facilities; and the free and unrestricted exchange of next-day operations data and studies between and among operating reliability entities.

1. *Do the TOPs in your region update next-day studies to reflect known outages and current system conditions? Are the next-day studies available to neighboring TOPs, including the status of planned outages of generation and transmission, and expected transactions?*

   RFC – PJM reviewing current process regarding next-day studies:
   - Completed solicitation from neighbors
   - Will assess enhancements to Joint Operating Agreements
   - Reviewing TOP procedures and interchange forecast assumptions used in day-ahead studies (4Q2012)

   SERC – Working to determine "trigger point" as to when next-day studies are updated prior to the next expected day. Planned revision to SERC Whitepaper on Planned Outage Coordination (October 2012)

   TRE – LCCs could benefit from having visibility into planned generation dispatch; e.g., sharing generation Current Operating Plan (COP) data. Continue to monitor developments in:
   - LCC to LCC and ERCOT to LCC sharing next-day study information
   - Possible enhancements to System Operator Test Environment (SOTE) to make available to LCCs

2. *Have TOPs and RCs completed studies identifying the sub-100 kV facilities that could, under severe or unusual conditions, have significant impacts on BPS reliability and model those facilities in their next-day studies? Are studies performed to evaluate the effect on sub-100 kV facilities when new transmission or generation facilities are added to the system?*

MRO – MISO Operations working with Operations Planning Working Group to develop methodology/criteria for monitoring sub-100 kV facilities.

SERC – Inclusion of sub-100 kV facilities in studies part of evaluation of Southwest outage recommendations. Will assess data to ensure all necessary sub-100 kV facilities are included.

TRE – Stakeholders discussing possible additional modeling needs for Private Use Networks. Continuing to seek feedback and monitor progress on standardization of ERCOT ISO procedures, including possible posting of contingency plans on ERCOT MIS.

Recommendations 11 – 16 cover a broad range of situational awareness issues, including: real-time visibility of external systems; adequacy of real-time tools; reliance on post-contingency mitigation measures; communicating the need for backup when Real-Time Contingency Analysis (RTCA) capabilities are lost or impaired; and inconsistencies between real-time and planning models.

1. *Do the TOPs and RCs in your area have RTCA tools that provide visibility of external systems?*

   RFC – PJM working with Transmission Owners to include additional sub-100 kV facilities; reviews include:
   - Capabilities and procedures
   - Level of external facilities monitored (4Q2102)
   - Improved documentation and training regarding EMS/RTCA failures (1Q2013)
   - RC staffing
   - Operator training/documentation for sub-100 kV facilities
   - External notification of RTCA failure – updated documentation

   SERC – Real-Time Modeling Working Group reviewing existing guidance.

2. *To what extent to TOPs in your region rely on other entities to perform real-time analyses for them?*

   FRCC – Two TOPs that currently rely on the RC agent for performing real-time contingency analysis (RTCA) for them plan to add RTCA tools to their Energy Management Systems (EMS).

   SERC – Limited number of TOPs rely on RCs for real-time analysis. Will be reviewed as part of investigation.

   SPP – 47% of TOPs rely on SPP RC for RTCA.

TRE – Continue to seek feedback on:

- LCC – LCC communications
- Study progress regarding SPS interactions in real-time applications
- LCC real-time visibility of outside systems
- Possible enhancements by ERCOT to SOTE
- LCC RTCA capabilities
- ERCOT reviewing plans regarding loss of State Estimator/RTCA functionality, application failure, and associated notification processes

3. *To what extent have the TOPs in your region incorporated the recommendations of the NERC Real-Time Tools Best Practices Task Force?*

   SERC – Recommendations will be reviewed by SERC Operations Planning Subcommittee.

   SPP – 41% of TOPs incorporate at least some of the Task Force recommendations. Others have recommendations under review.

4. *What steps are taken to ensure consistency between real-time and planning models?*

   SERC – Additional follow up to Model Data Validation requirements by Regional Studies Steering Committee plus Dynamics Review Subcommittee to achieve more consistency.

   TRE – ERCOT Operations and Planning Synchronization Task Force (formed in Spring 2012) to address enhancements to planning and operating processes regarding models and modeling data.

5. *To what extent do any of your TOPs rely on post-contingency mitigation measures? If so, how are these measures evaluated to ensure they do not lead to cascading outages under severe or unusual system conditions? Are affected neighbors notified of possible ramifications of these post-contingency measures?*

   SERC – Near-Term Study Group: SERC Operating Committee asked to examine whether current operating processes and procedures ensure post-contingency plans allow enough time for operator action (30 min.)

   TRE – ERCOT and LCCs reviewing procedures for development of post-contingency mitigation plans. Will also follow up on process review needed on how protection system settings are considered by ERCOT/LCC in developing post-contingency mitigation plans. Need to include consideration of time needed by system operators to take action.

Recommendation 17 addresses the need for consideration, both in advanced studies and in real-time operations, of sub-100 kV facilities operated in parallel with the BPS that can have an impact on bulk power system reliability.

1. *What steps are taken to ensure that sub-100 kV facilities that could impact bulk power system reliability are considered in both real-time and advanced studies, especially during severe or unusual system conditions?*

   SERC – See response above.

Recommendation 18 refers to the identification and recognition of Interconnection Reliability Operating Limits[1] (IROLs), both in day-ahead studies and in real-time operations.

1. *What procedures are used to identify IROLs within your region and how are these limits shared and coordinated within the region and with neighboring regions?*

   RFC – working with facility owners to validate that all generation and transmission facilities and protection systems that affect BPS reliability are taken into account.

   SERC – SERC Operating Committee asked to assist in determining if additional guidance is needed in day-ahead and real-time.

   TRE – ERCOT ISO SOL/IROL procedures under review prior to NERC request. TRE is monitoring progress.

Recommendations 19 – 26 address multiple issues related to protection systems, including: regular review, analysis, and coordination of special protection systems with and among interconnected systems, especially under adverse system conditions; sensitivity of turbine control systems during extreme events; communicating to neighboring systems and RCs equipment overload relay settings that are below or only marginally above applicable ratings; reflecting overload relay settings in the determination of System Operating Limits (SOLs).

1. *Do TOPs share with their respective RC and neighboring TOPs overload relay trip settings on transformers and transmission lines that could impact the reliability of the BPS?*

   SERC – SERC Engineering Committee reviewing SERC Facility Connection Requirements Guidelines to determine effectiveness at addressing loadability.

2. *Do TOs use overload trip settings below 150 percent of the normal rating or below 115 percent of the highest emergency rating, whichever of these two values is greater? If*

[1] NERC Glossary Definition of IROL: A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Power System.

these conditions exist, do TOPs share their operating procedures for mitigating the problem? Are these operating procedures pre or post contingency and, if post contingency, is there enough time for operators to initiate the procedures based on the time delays associated with the relay settings?

FRCC – Further analysis needed to confirm that TO overload relays on sub-200 kV facilities are not set below 150 percent of the normal rating or below 115 percent of the highest emergency rating, whichever of these values is greater.

RFC – Review of all protection processes underway: settings; validation of ratings; transformer overload protection settings; validation of load responsive relay settings.

SERC – SERC Engineering and Operating Committees assisting in addressing appropriate margin between relay settings and ratings.

TRE – Continuing dialog on:

- LCC consideration of relay settings in developing ratings and coordination with other LCCs, especially with respect to post-contingency mitigation plans
- Recognition in operating tools of when overload relay settings exceed ratings

3. *How frequently are special protection systems in your region reviewed for their continued necessity and their coordination with other similar systems and within the interconnection? Do these reviews evaluate the consequences of inadvertent operation of special protection systems?*

   TRE - Will seek feedback/discussion and monitor study process updates regarding incorporating effects of SPS interactions in real-time applications.

4. *What efforts are underway to evaluate the performance of generators under severe or unusual system conditions, especially with regard to the behavior of turbine control systems and underfrequency relay coordination?*

   NPCC – Governor response/dynamic model validation underway.

   SERC – Nothing underway currently; SERC Engineering Committee asked to evaluate issue of sensitivity of acceleration control functions in turbine control systems.

   SPP – No SPP RC efforts underway; being addressed in planning horizon by individual TPs as part of their transient stability studies. Benchmarking dynamic models difficult given limited availability of real-time measurements.

Recommendation 27 addresses the need for tools to determine, in advance of contingencies, the angular separation following line trips under a wide range of system conditions, as well as the need for plans for reclosing lines with large phase angle differences.

1. *Do TOPs and RCs have the ability to determine, in real time, the standing angles that would result following major transmission line outages?*

   RFC – PJM exploring additional capabilities:
   - How handled in EMS
   - Additional PMUs (3Q2013)
   - Real-time dispatch monitoring tools and training (4Q2013)
   - Establishing baseline angles from installed PMUs (4Q2013)

   SERC – SERC OC asked to develop guide for appropriate tools for use by operators in resolving angular separation event issues as well as training of operators.

   SPP – One-third of TOPs have capability in real-time. One TOP plans to link tabular data they have now to their displays.

   TRE – Will seek feedback with respect to concerns regarding standing angles that would result from transmission line outages, and ability to predict post-contingency angles.

2. Are there PMUs or PMU-capable digital relays located and streaming data such that post-contingency angles can be seen directly in SCADA/EMS systems?

   FRCC – TOPs exploring streaming of PMU data into EMS systems.

   MRO – Exploring potential enhancements as part of NASPI effort.

   NPCC – The New York ISO is implementing a synchro-phasor monitoring network for improved situational awareness; PMU data will also serve as input to certain EMS hosted applications. New York ISO implementing synchro-phasor monitoring process; PMU data streaming into EMS system being evaluated.

   SERC – Still evaluating the streaming of PMU data into SCADA/EMS systems.

   SPP – No capability to stream PMU-capable relay data on angles into SCADA/EMS systems.

   TRE – ERCOT and other registered entities have discussed future PMU applications; long-term effort.

3. *Do RCs have predetermined plans for reducing angles to within synchro-check relay settings to allow prompt reclosing of lines?*

   MRO – No predetermined plans for reducing angles.

SPP – No specific predetermined plans.

Group B: Longer-Term and Seasonal Planning Issues

Recommendations 5 – 8 address the responsibilities of TOPs for seasonal planning, especially in terms expanding the scope of their seasonal planning studies to include external facilities and the impact of sub-100 kV facilities, both internal and external to the TOP's system, on bulk power system reliability. The recommendations also stress the importance of sharing information with neighboring TOPs and the RC regarding overload relay trip settings that fall below or near the emergency ratings of their facilities.

1. *How are TOPs in your region alerted to planned outages external to their systems?*

2. *Do seasonal studies evaluate your entire regional footprint whereby TOPs can see the effect on one area from a contingency occurring in another area? If not, how does your seasonal planning process ensure there are no study gaps/seams between parts of the region?*

   NPCC - All TOPs within the NPCC footprint have reciprocal agreements to coordinate their planned outages that may impact facilities outside of their immediate operating area.

   RFC – Interviews indicated lesser degrees of overlap in the seasonal processes, which results will be presented to Reliability Committee for review at September 2012 meeting:
   - Four Transmission Owners not supplying information on 69 kV facilities in the power flow models shared with neighboring entities
   - Many Transmission Owners not evaluating N-1-1 conditions for external contingencies
   - Routine performance of assessments for Spring and Fall seasons

   TRE – Will continue to monitor Private Use Network requirements to refine the need to include them in studies.

3. *In the Eastern Interconnection, how is coordination performed with neighboring regions to ensure the effects of a contingency in one region are known by neighboring regions?*

   NPCC - The NPCC has operating and planning agreements with neighboring regions/systems to actively share and coordinate information with neighboring systems such as the MISO, RFC, and PJM.

4. *In the seasonal study process are appropriate elements, including those below 100 kV that can affect the reliability of the BPS, studied in contingency analysis?*

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NPCC - Within the NPCC region, Document A10, "Classification of Bulk Power System Elements," defines the methodology used to classify system elements as part of the bulk power system, and it specifies that elements shall not be included or excluded from the bulk power system based on a particular voltage class.

SERC – Included in evaluation of recommendations that is being performed by SERC registered entities.

TRE – Seeking feedback on:

- Processes to notify ERCOT and LCCs regarding most limiting elements in facility ratings, with emphasis on relays.
- Processes for recognition in operational tools of relay overload settings that exceed or are equal to ratings.

5. *Are seasonal studies performed for shoulder periods such as spring and fall when transmission elements and generators may be scheduled out of service for maintenance?*

NPCC - Transmission studies for shoulder or light load periods are performed, as required; to determine transfer limits and special operating instructions for planned outage conditions.

SPP – 81% of TOPs perform shoulder period studies; others continue to evaluate and consider need as appropriate.

Recommendations 9 – 10 focus on the importance of addressing gaps in the planning processes of REs, TPs, and PCs, especially where these gaps result in a lack of consideration for critical system conditions, impact of sub-100 kV facilities, interaction of protection systems, and failure to benchmark models against actual system conditions that occur during unusual system events.

1. *Do the near- and long-term planning studies conducted by TPs and PCs evaluate the impacts of major transmission outages under heavy transfer conditions?*

NPCC - Within the NPCC, transmission planning studies required for the comprehensive area transmission review (CATR) are performed under stressed system conditions, with all elements in service and with one critical element out of service followed by any design contingency including planned outages of bulk electric equipment. The CATR also evaluates the system under extreme system conditions such as extreme weather and gas supply shortage, considering contingency transmission outages under heavy transfer conditions.

SERC – Beyond 5 years, limited transfers committed. SERC committees to define methods to identify expected future transfers for use in studies.

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SPP – 43% of TPs do not do such studies; rely on SPP RC studies.

2. *Do these studies evaluate the impact of such outages on sub-100 kV facilities, especially those operated in parallel with the BPS, to determine whether any potential exists for system cascading?*

   NPCC – In the NPCC, most sub-100kV sub-transmission facilities are modeled in the coordinated databases used to conduct planning studies. The NPCC A-10 test identifies which elements impact the BPS or have the potential to cause system cascading. The New England investigationing of further inclusion of sub-100 kV facilities in planning studies is continuing.

   SERC – Further investigation to identify depth and detail of sub-100 kV facilities.

3. *How do the PCs in the Region ensure that near- and long-term planning studies address the interaction of various protection systems, especially special protection systems that are designed to operate post-contingency?*

   NPCC - Special Protection Systems (SPS) are reviewed in conformance with NPCC Reliability Reference Directory #7 requirements whenever a new SPS is added, retired, or modified. Also once every five years, as part of NPCC's comprehensive transmission review process, each SPS is checked for impact and interaction with other SPS. Checks include correct operation, potential for miss-operation or failure to operate.

   SERC – SERC EC to evaluate interaction of SPS and whether and how to include in Near-Term Study Group process.

4. *Are models benchmarked against real system conditions, especially severe and unusual system conditions?*

   NPCC - Under the direction of the NPCC Task Force on System Studies (TFSS), working groups benchmark power flow cases based on realtime actual conditions.

   SERC – Additional follow up by Regional Studies Steering Committee and Dynamics Review Subcommittee to achieve consistency. Comparison of simulations to actual conditions will be used to determine need to adjust models.

   SPP – SPP RC working toward benchmarking its models based on ERAG action plan and NERC Model Validation Working Group initiative.

   TRE – See comments above on work of Operations and Planning Synchronization Task Force.

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5. *Do system dynamic studies take into account relay and UFLS schemes?*

   NPCC - Yes, both are modeled in the PSSE dynamics cases used for System Impact Studies.

   TRE – Will further examine protection system coordination and evaluation of other impacts in dynamic case creation, particularly for overload relays.

NEWS RELEASE

For Immediate Release:
December 19, 2012

NYISO Issues 2013-2017 Strategic Plan

Sets Objectives for the next Five Years

RENSSELAER, N.Y.— Enhancement of electric grid reliability through improved power flows, market coordination, technological innovation and collaborative planning are key elements of the New York Independent System Operator (NYISO) *2013-2017 Strategic Plan*.

The five-year plan, approved by the NYISO Board of Directors, incorporates long-term objectives, financial discipline and operational priorities based on the board's review of the economic and regulatory outlook, economic and environmental factors affecting market participants and the growing interest in using competitive wholesale electricity markets to achieve public policy priorities.

"We see a growing need for interregional cooperation among markets to optimize grid operations, enhance market efficiency, implement comprehensive system planning and integrate technological advances into the grid to help consumers realize benefits from competitive wholesale markets," said NYISO Board Chair Robert Hiney.

At the center of the NYISO's strategic plan is a vision of broader regional markets based on collaborative efforts among neighboring grid operators to optimize system efficiency and preserve reliability through the shared use of grid resources. This strategic vision acknowledges that reliability and economic efficiencies will be enhanced through expanded planning and operational coordination among market administrators. Broadening the pool of grid resources through enhanced market design will expand competition and enable operators to better respond to dynamic market and operating conditions across market borders.

To achieve its regional strategy, the NYISO envisions:

- Optimizing the economic flow of electricity across borders through improved coordination of market rules and the increased flow of real-time data on system conditions;
- Coordinating planning processes that facilitate transmission investments in support of reliability, economic efficiency and public policy activities;
- Deploying smart grid technologies that maintain system balance through the use of robust data, communications and automated systems; and

- Developing a shared understanding of regional gas delivery constraints for power generation as well as a commitment to address them collaboratively.

The strategic objectives guiding the initiatives outlined in the NYISO's Strategic Plan include maintaining its role as a leader in grid reliability, a leader in market design and performance, excellence in execution in all aspects of its work, maintaining robust planning processes, fostering technological innovation and serving as an authoritative source of information for policymakers, market participants and consumers. The NYISO plans to pursue these objectives through:

- Implementing Broader Regional Markets initiatives designed to enhance regional market efficiencies;
- Addressing the need for expanded coordination between the electric system and natural gas industry;
- Assessing the relationship of capacity markets and generator retirements to preserve reliability and market efficiency as older, less efficient generators seek to exit the market;
- Deploying smart grid technologies that increase situational awareness of conditions on the grid within and outside of New York's borders; and
- Enhancing demand response programs to further benefit consumers with improved market efficiencies and reduced wholesale prices during peak demand periods.

For more information, please see the *2013-2017 Strategic Plan*, which is available on the NYISO website, *www.nyiso.com*.

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The New York Independent System Operator (NYISO) is a not-for-profit corporation responsible for operating the state's bulk electricity grid, administering New York's competitive wholesale electricity markets, conducting comprehensive long-term planning for the state's electric power system, and advancing the technological infrastructure of the electric system serving the Empire State.

2013 – 2017 Strategic Plan

New York Independent System Operator



NYISO

NYISO markets *"deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that resources are started and dispatched each day to meet the system's demands at the lowest cost."*

2011 State of the Market Report for the New York ISO Markets,
Potomac Economics, April 2012

INTRODUCTION

The NYISO, a not-for-profit corporation, began operating at the end of 1999. Its core responsibilities include:

- *Reliable operation of New York's bulk electricity grid,*
- *Fair and open administration of competitive wholesale electricity markets,*
- *Planning for the future of New York's power system, and*
- *Advancing the technological infrastructure of the electric system serving New York.*

The NYISO is governed jointly by an independent Board of Directors; with extensive experience in the power industry, finance, academia, technology, communications and government; and its Market Participants, including transmission owners, generation owners, other suppliers, end-use consumers, public power and environmental parties.

All Board members and staff are required to be independent from the interests of Market Participants as part of a rigorous NYISO Code of Conduct. The NYISO fulfills its core mission by reliably operating New York's bulk electricity grid. We manage the state's supply of electricity along more than 11,000 circuit-miles of high voltage transmission lines. It is a serious and complex responsibility that we work to fulfill 24 hours-a-day, every day of the year.

In its administration of New York's wholesale electricity markets, the NYISO serves as a fair, impartial administrator that maintains open, competitive access to the markets and monitors power-trading transactions, thereby enabling the competitive marketplace to provide power at the lowest possible cost. From 1999 through 2011, transactions in the NYISO markets have totaled nearly $90 billion.

The NYISO is concerned not just with the needs of today's electricity consumers, but tomorrow's, as well. It conducts a planning process that assesses the state's electricity needs over a 10-year horizon, and evaluates the feasibility of proposed projects to meet those needs.

NYISO operations and practices are mandated through tariffs (federal regulations having the force of law), statutes, regulations and binding agreements with various state, federal and independent entities, including the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), the New York State Public Service Commission (NYS PSC), the New York State Reliability Council (NYSRC), the Northeast Power Coordination Council (NPCC), and other government and oversight organizations.

The NYISO is committed to achieving the objectives and implementing the goals of the 2013-2017 Strategic Plan in a fair and open manner attentive to all perspectives. Our efforts to build on our success, as we strive to make New York's electricity grid smarter, greener and more efficient, will be guided by this Strategic Plan.

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Purpose

The purpose of the Strategic Plan is to establish the strategic direction for the organization and create a foundational strategy that balances long-term objectives, operational priorities, and financial discipline. The plan reflects the perspectives of the NYISO's Board of Directors, NYISO's senior management, customers, and other stakeholders. It serves as a communications tool for the NYISO Board of Directors, employees, and stakeholders.

The plan outlines the Vision, Mission, Guiding Principles, and Core Values under which the NYISO will operate over the next five years, and defines the company's strategic objectives and initiatives for that time period.

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VISION - Looking to the Future

The NYISO will be a leader in developing a broader regional strategy for accomplishing our mission, based on cooperative efforts among RTOs, to optimize system efficiency and preserve reliability. This will be achieved through the shared use of grid resources that improve our ability to respond to dynamic market and operating conditions across market borders.

Achieving this broader regional strategy will require a commitment among RTOs to:

- *Optimize the economic flow of electricity across borders;*
- *Coordinate planning processes that facilitate transmission investments in support of reliability, economic efficiency, and public policy activities;*
- *Deploy smart grid technologies that maintain system balance through the use of robust data, communications, and automated systems; and*
- *Develop a shared understanding of regional gas delivery constraints for power generation as well as a commitment to address them collaboratively.*

An effective broader regional strategy will enhance reliability and expand the benefits of competitive markets in local markets, while preserving the local market governance structures.

MISSION

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefit to consumers by:

- *Maintaining and enhancing regional reliability*
- *Operating open, fair and competitive wholesale electricity markets*
- *Planning the power system for the future*
- *Providing factual information to policy makers, stakeholders and investors in the power system*

GUIDING PRINCIPLES

- Continually strive to enable market and reliability requirements to complement each other
- Provide a market environment that attracts investment in energy infrastructure
- Institutionalize Excellence in Execution
- Maintain independence and objectivity on issues which affect our market
- Seek innovative solutions while strictly adhering to existing laws, regulation and tariff requirements
- Foster regulatory certainty and market transparency

CORE VALUES

The Core Values of the NYISO establish the foundation from which all our responsibilities and accountabilities are delivered:

- *Accountability – Taking responsibility to do what needs to be done*
- *Quality – Commitment to excellence in all our processes, systems and products*
- *Integrity – Commitment to honest and ethical actions*
- *Team Work – Working together, succeeding together, respecting each other*
- *Customer Focus – Listening, caring, delivering*
- *Innovation – Pursuing creative and sound solutions*
- *Enthusiasm – Having a passion for our work and our interaction with our customers, stakeholders and policy makers*

STRATEGIC OBJECTIVES

A Leader in Reliability

Promoting resource adequacy and transmission security now and in the future

Sustain and enhance reliable operation of the bulk electricity grid and the wholesale electricity markets

A Leader in Market Design

Develop enhancements to the wholesale electricity markets that increase reliability and market efficiency and create value for consumers

Foster a market environment conducive to new investments in the wholesale electricity markets that attracts and retains resources needed in the state

Excellence in Execution

Sustain a culture that promotes and strives for flawless performance in all that we do and engenders customer confidence in our operations, markets, and planning

Sustain and Enhance Robust Planning Processes

Strengthen planning capabilities to effectively implement the Comprehensive System Planning Process (CSPP), which includes reliability, economic, and public policy planning studies and other planning initiatives in New York.

Coordinate with Market Participants, State and Regional Planning Agencies and other key Stakeholders to complete studies and to analyze reliability, operations and market impacts of a broad range of energy-related federal and state level policy goals, including environmental, fuel diversity, energy efficiency and renewable integration

A Leader in Technology Innovation

Work with Regulators and other Stakeholders to coordinate Smart Grid standards and protocols and implementation

Develop innovative market products and information architecture for integrating renewable resources and other new technologies needed for reliable grid operations

Authoritative Source of Information on Key Issues

Take a proactive leadership role in providing an independent, unbiased source of information on the operation of the bulk power system and wholesale market in New York, and identifying future needs by analyzing the reliability, environmental and cost attributes of policy and technology choices

Conduct stakeholder outreach activities in leadership forums, national and international conferences, as well as professional and standard setting groups

STRATEGIC INITIATIVES FOR 2013-2017

In order to achieve our strategic objectives, NYISO key initiatives between 2013 and 2017 include:

Expanded Gas-Electric Coordination

- Enhance NYISO operations and planning in an environment of expanded dependency on natural gas-fired generation, renewable generation, and retirements of less efficient generation
- Increase NYISO Control Room visibility into the operations and maintenance of the gas pipeline system serving New York generators
- Enhance maintenance coordination between the gas and electric systems to minimize the chances for supply disruptions to impact electric system reliability and/or market efficiency
- Initiate and complete an interregional gas/electric study to examine the impacts of natural gas expansion on bulk power systems in the near and long-term and incorporate relevant findings into economic, reliability, and public policy planning processes.
- Develop market design for electric energy storage to address generator intermittency and gas pipeline contingencies

Robust Planning: Eastern Interconnection Planning Collaborative, Transmission Expansion, and Public Policy

- Sustain an ongoing EIPC structure
- Implement FERC Order 1000's call for a public policy planning process while protecting competitive markets
- Provide technical support for the State's Energy Highway Initiative and new initiatives in System Planning
- Provide NYISO independent analysis to Market Participants, state or federal agencies, and standard setting entities

Capacity Markets and Generator Retirements

- Enhance capacity markets
- Implement enhancements to scarcity pricing
- Evaluate the effectiveness of market exit and re-entry rules. Analyze mitigation and deliverability requirements

Broader Regional Markets

- Develop market performance metrics
- Implement market technology performance improvements (including MIPS)
- Assume a leadership role in working with neighboring RTO/ISOs to establish a broader regional market
- Deploy five-minute dispatch with HQ
- Evaluate and deploy Phase II of Interregional Transaction Coordination: Ancillary Services
- Develop and deploy Coordinated Transaction Scheduling with ISO-NE
- Design and deploy Coordinated Transaction Scheduling with PJM
- Evaluate and deploy Intra-hour Transaction Scheduling with Ontario
- Evaluate and deploy Market to Market Coordination with ISO-NE

Smart Grid

- Implement new primary and alternate control centers with new PMU technology
- Continue projects to reinforce/enhance cyber security protocols and best practices
- Implement Enterprise Project Management
- Implement Stakeholder Services Suite
- Support development of Smart Grid and other new technologies (e.g. ramping and storage, black start, regulation, quick start capacity, and others)
- Enhance operational & communication capabilities of PMU system
- Support the evolution of Dynamic Pricing and identify potential technology and market solutions
- Perform business case analysis for New York State energy sector network
- Conduct stakeholder outreach activities in leadership forums, conferences, and professional and standard setting groups

Demand Response

- Increase the effectiveness of Demand Response resources
- Evaluate improvements in demand-side resource performance audits and compliance mechanisms
- Enhance verification and compliance systems for Demand Response resources

Commitment to Collaboration

The NYISO strives to achieve its strategic objectives with the direct involvement of market stakeholders and the guidance of policy makers, regulators, and other stakeholders.

As it serves the greater interest of the state and the people of New York, the NYISO's efforts are most visible in the forum it provides to share ideas on how to solve problems and resolve issues.

With hundreds of Market Participants, the NYISO engages voices from all sectors of the electric industry. The NYISO's achievement of its objectives is directly assisted by the involvement of participants in the shared governance committee process. By maintaining this open process, the various elements of the NYISO's mission are understood by all who participate. This interdependent system and commitment to collaboration is an invaluable asset as the NYISO moves forward to address the challenges to come.

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Long Term Incentive Goals

The NYISO's overall management strategy includes programs designed to provide competitive levels of compensation that advance the NYISO's long-term performance objectives, pay executives for their performance, and assist the NYISO in attracting, retaining, and motivating the highly skilled employees required to lead the organization.

Among the programs is a long-term incentive plan that provides the opportunity to award eligible employees who contribute materially to the achievement of certain NYISO objectives, established by the Board of Directors, that are tied to the implementation of the NYISO's corporate vision and strategic plan. The goals are established for three-year performance cycles. The 2013-2015 Long-Term Incentive Goals include:

- *Improving the operational coordination between the gas pipeline delivery system and the New York bulk electric system to preserve electric system reliability and maintain competitive and efficient markets;*
- *Assuming a pivotal role in upgrading and modernizing New York's transmission and generation infrastructure, and in ensuring that such efforts complement and support competitive wholesale power markets;*
- *Enhancing capacity markets as necessary, including the increased integration of demand response into real-time markets in a manner that is comparable to other "supply" resources, in order to maintain system reliability and operate efficient markets;*
- *Assuming a leadership role in establishing Broader Regional Markets that allow electricity to flow more readily across market borders to respond to real-time economic and reliability conditions on the grid;*
- *Facilitating the emergence of an automated transmission system that optimizes resource use for maximum system efficiency while continuously adapting to dynamic operational conditions spurred by increased penetration of renewable resources and increased load variability due to the emergence of smarter end-use technologies; and*
- *Improving cost tracking capabilities that will provide us with the capability to assign costs for projects to the appropriate stakeholders based on cost-causation principals, if desired.*

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The New York Independent System Operator (NYISO) is a not-for-profit corporation responsible for operating the state's bulk electricity grid, administering New York's competitive wholesale electricity markets, conducting comprehensive long-term planning for the state's electric power system, and advancing the technological infrastructure of the electric system serving the Empire State.

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NEW YORK INDEPENDENT SYSTEM OPERATOR
10 Krey Boulevard, Rensselaer, NY 12144

NPCC Task Force on Coordination of Operation
Final Meeting Minutes
Thursday, November 29, 2012-8:00 AM to 5:00 PM
Friday, November 30, 2012-8:00 AM to 1:00 PM
Omni Mont Real Hotel
Montreal, Quebec

In attendance:

Dwayne Basler *	Northeast Utilities
Jim Castle*	New York ISO
Dave Daley* (Chair)	NBSO
Frank Koza	PJM
Leonard Kula*	IESO
Daniel Lefebvre*	TransÉnergie
Richard Mailhot*	TransÉnergie
Jerry Mosier	Northeast Power Coordinating Council
John Norden (Vice-chair)*	ISO-New England
Paul Roman	Northeast Power Coordinating Council
Mike Schiavone*	National Grid
David Stanford*	Nova Scotia Power
Dan Taft (telephone 11/29 AM)	Con Edison
Paul Tremblay*	Hydro One
Mike Potishnak	ISO-New England
Stephen George (telephone 11/30 PM)	ISO-New England
De Tran (telephone 11/30 PM)	New York ISO

* Voting TFCO member or proxy.

1. Administrative Items

Determination of Quorum

Quorum requirements were satisfied with ten TFCO voting members in attendance.

Approval of the "Draft for Approval" Minutes of the Task Force on Coordination of Operation Meeting of October 17-18, 2012

The draft minutes were approved as revised and will be issued and posted on the NPCC web site.

Roster and Mailing List Changes

There were no changes to the TFCO roster.

The tfco-members and tfco-all mailing lists were reviewed:

- The tfco-all list will be eliminated
- The tfco-members list will include the TFCO members, alternates and regular participants.
- TFCO correspondence that needs to go to others should include their e-mail addresses.

Action Item: Changes will be made to the TFCO exploder lists: 1) The tfco-all list will be eliminated, 2) The tfco-members list will include the TFCO members, alternates and regular participants and 3) TFCO correspondence that needs to go to others should have their addresses explicitly listed when sending e-mails. NPCC staff will make the changes.

TFCO 2013 Meeting Dates and Locations

The 2013 TFCO meeting dates were confirmed:

- TFCO-January 17-18 in Montreal (1/17 8:00 AM to 5:00 PM and 1/18 8:00 AM to 1:00 PM)
- TFCO-March 20-21 New York (3/20 8:00 AM to 5:00 PM and 3/21 8:00 AM to 1:00 PM).
- TFCO-May 15-16 in Syracuse (5/16 8:00 AM to 5:00 PM and 5/17 8:00 AM to 1:00 PM)
- TFCO-August 28-29 in Halifax (8/28 8:00 AM to 5:00 PM and 8/29 8:00 AM to 1:00 PM).
- TFCO-October 17-18 in Toronto (10/17 8:00 AM to 5:00 PM and 10/18 8:00 AM to 1:00 PM)
- TFCO-December 5-6 in Boston (12/5 8:00 AM to 5:00 PM and 12/6 (8:00 AM to 1:00 PM).

Exhibit 1 provides a summary of the TFCO / TFCO Working Group / RCC / and NERC group meetings in 2013.

TFCO Meeting Topic Discussion Leads

For future TFCO meetings some members will be designated to lead discussion on specific agenda topics.

CO-7 Ad Hoc Operational Planning Working Group Staffing

CO-7 members will include:

Jonathan Pollock	NBSO
Jim Helton	ISO-New England
Dave Mahlmann	New York ISO
To be named	IESO
Charles Éric Langlois	TransÉnergie
Lynda Ozere (D#1)	Nova Scotia Power
Rod Smith (CIP Standard)	Nova Scotia Power
Vandan Divatia (D#1)	Northeast Utilities
Sandra O'Neill (CIP Standard)	Northeast Utilities
To be named	Con Edison
To be named	Hydro One

TFCO members will name the additional representatives to the CO-7 ad hoc group.

Tasks the CO-7 group will work on will include:

1. Summary of the facilities that apply for the CIP standards using the table provided by TFIST.
2. Directory #1 operations content development
3. Southwest Outage

CO-12 Working Group

The CO-12 Working Group will be renamed the "System Assessment Working Group" to more closely reflect the activities of that group.

2. Operating Conditions

Hurricane Sandy Impact Reports

New York

- As the Storm approached extra staffing commitments were made in preparation. Also, all unnecessary system maintenance work was cancelled.
- On October 29 a Storm Alert was declared and some units were brought on line for voltage control. At 4 PM a gradual loss of transmission and generation started. At 9 PM to prevent high voltages some 345 kV lines were taken out of service.

Con Edison and southeastern New York

- Storm surge was 11 to 14 feet. That was 2 feet higher than the maximum pre-storm forecast.
- At the peak of the outage 750,000 to 900,000 Con Edison customers were out. Long Island at the peak of the outage lost 90% of the customer base and was down to 500 MW load.
- The Astoria 5 generator tripped because of sheet metal debris striking equipment. East River generation had been shut down pre-emptively to avoid equipment damage.
- Control equipment flooded in salt water was a major setback for quick restoration.
- About 2/3 of the Con Edison 345 kV circuits tripped with about 60% of them left unavailable due to the tripping or through isolation. The 13th Street Substation was shut down (transmission and subtransmission).
- About of 1/3 of the 138 kV circuits and subtransmission circuits were out of service.
- Seven large generators were lost (4,100 MW). Ravenswood Units #1, #2, #3 and #4 remained in service and performed well throughout the period of restoration of facilities.
- Repressurizing underground cables was a concern during the restoration process

ISO-New England

- At the peak of the outage 1,400,000 New England customers were out (23% of the load). Sustained winds were 60 MPH with gusts to 75 MPH.
- Some substations were out due to flooding, including Bridgeport Harbor and Norwalk.
- 7,000 MW of generation was out.
- There were approximately 70 circuit operations on transmission facilities and there were approximately 36 sustained circuit outages. No IROLs or SOLs were identified. Portions of the United Illuminating System were shut down.
- Several generators near the coast were brought on line pre-emptively but they were lost during the Storm. However, because they were hot, they were able to be restored to service quickly.

PJM

- 140 lines were out at the peak of the outage, mostly 230 kV and below. That included the Neptune DC cable to Long Island, the Linden Variable Frequency Transformer and the Linden-Goethals 230 kV tie to Con Edison. Flooding of many substations was a major problem.

- 40 generators were lost (7,000 MW) including some that were taken out prior to the storm for protection of equipment.
- At the peak of the outage 5,000,000 PJM footprint customers were out (60,000,000 people). Because of the large loss of load high voltage levels were a major operating concern.
- The most significant damage was along the New Jersey coastline. Snow in West Virginia caused many high voltage circuit problems.

Ontario

There were not major effects from the Storm in Ontario. Several lines had galloping conductors and some 115 kV, 44 kV and 27 kV circuits tripped. About 160,000 customers were out (500 MW of load). Simultaneous Activation of Reserve energy was available to other participants if it was needed.

Update on Non-Storm Operating Conditions

In New Brunswick the Pt. Lepreau nuclear generator returned on November 23, 2012 following the long refurbishment outage. It is now rated at 705 MW (660 MW net output).

3. Update of NPCC Facilities for Notification Lists

The 2012 updates of the 5 Reliability Coordinator Area and PJM lists were reviewed. Type I SPSs are included. The PJM facilities will be added to the NPCC Area lists and some appropriate PJM contacts will be provided access.

The normal practice among Reliability Coordinators is to notify neighboring RCs if one of the list facilities is out of service or has a state change.

Action Item: The 2012 updated Facilities for Notification Lists will be posted on the access-restricted location on the NPCC web site. This location can be accessed on the CO-8 page. NPCC will post the updates and check the list to ensure only TFCO members and alternates, CO-8 members and alternates and PJM contacts can access this information.

4. NPCC Regional Reliability Reference Directory 1, "Design and Operation of the BPS"

The TFCO members discussed the possible approaches to use to complete the Directory 1 operations content revisions. A concern was raised that revisions to the operations sections are not fully taking into account the changes to the system design portion of the document. This approach may lead to changes that contradict the changes to the operations portion.

The CO-7, Operational Planning Ad Hoc Working Group will be enlisted to determine proposed changes to the operations sections and develop the appropriate language. While making these changes to the operations section the CO-7 group will need to be aware of corresponding design section content and try to harmonize the revisions between the sections.

High level discussions are presently underway to resolve some differences on interpretations of the contingency operation portion of the document. Once agreement is reached on a consistent interpretation then a conference call with the Task Force on Coordination of Planning will be set up to develop a plan to provide consistency between the operations and system design requirements content in Directory 1.

5. BAL-003-1, "Frequency Response and Bias"

Mike Potishnak provided a summary of the status of approval steps for the BAL-003-1, "Frequency Response and Bias" standard. A revised version of BAL-003-1 was posted for NERC ballot with a vote ending date of November 5. It passed the ballot but will be sent out again for recirculation comments. The official vote will not come until all comments have been reviewed and addressed. The earliest estimate for an approved BAL-003-1 is December 2013.

Key differences from BAL-003-0 are that:

- A consistent method will be used for measuring Interconnection and Balancing Authority frequency response.
- All BAs will need to provide to NERC extensive frequency response performance information for 20 to 35 events each year.
- NERC will evaluate frequency response information and determine proper frequency bias settings for the BAs to use in their AGC Systems.
- NERC will determine the Resource Contingency Protection Criteria for the Interconnection. Presently the target for the Eastern Interconnection is to avoid frequency change to activate the common highest underfrequency load shedding settings of 59.5H.

6. Event Analysis

a) Churchill Falls loss of 3,184 MW Event-July 15, 2012

A detailed report has not been completed at Hydro-Quebec-TransÉnergie so the discussion of this event was deferred to the next TFCO meeting.

7. Southwest Power Outage-September 8, 2011

At the October meeting TFCO agreed to develop a plan to review all actions previously identified in the August response to NERC regarding the Southwest Power Outage

investigation. This review would be used to determine if there are any gaps between what is presently being done to what is indicated in the Southwest Outage recommendations. TFCO reviewed each of the Southwest Outage report recommendations pertaining to system operation:

Recommendation 1: All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.

All NPCC RCs and TOPs effectively share these studies and results, as necessary. What exactly is meant by "next day studies" was questioned.

Recommendation 2: TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.

It was suggested that the next day studies of the RCs include all of the facilities included on the neighboring system Facilities for Notification Lists. The TFCO RC representatives should check to determine if these facilities are included.

Recommendation 3: TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.

All NPCC RCs and TOPs feel that their studies effectively capture such subtransmission facilities.

Recommendation 4: WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.

Recommendation 5: WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.

Recommendation 6: TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.

Recommendation 7: TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.

Planning and operational planning studies normally address various system load and seasonal conditions.

Recommendation 8: TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.

Some NPCC TOPs use additional facility ratings beyond normal, long time (or term), short time (or term). ISO-New England uses a Drastic Action Limit (DAL), which is used to indicate facility loading approaching the protection trip setting. EMS systems are designed with the present RC / TOP limits and changes to EMS systems to add additional ratings would be costly and labor intensive.

The recommendations emphasize thorough coordination with neighbors and visibility of the impacts of contingencies outside of RCs in EMS displays. TFCO had previously requested the CO-10 Working Group to develop a process for NPCC coordination of modeling of representations in EMS systems of external systems. This wide area view coordination would help to ensure good models of adjacent systems and should include some contingencies in other systems.

TFCO members agreed that development of a formal NPCC process for updating and maintaining a procedure for EMS models. TFCO members felt there is a need for a "C" document to document this.

8. Survey of TOs and RCs on Monitoring the Status of Type I Special Protection Systems; Develop a Checklist for the Operational Review of a Special Protection System

The RCs reported on control (status) point monitoring for arming of their Type I SPSs:

New Brunswick— A project to make telemetry upgrades to provide the status points of all Type I SPS control points in the control room is underway.

New England—The status of all Type I SPSs is provided by the Transmission Operators to ISO-New England. Presently, some status points are available in the control room and some are not. The availability of these is dependent on what the Transmission Owners can provide. In some cases someone must be available at the substation to check and provide the status point information. No project is underway yet to make sure the system operators in the control room have telemetry of all control (status) points.

New York—Updates on Type I SPS availability is provided on the EMS display pages.

Ontario—The Hydro One control room has the status of all Type I SPSs. For the Bruce SPS, IESO receives all status points but not all status points are available for some other Type I SPSs.

Hydro-Québec-TransÉnergie--Telemetry on each piece of equipment for the two Type I SPSs is available in the control room.

PJM--Telemetry of the status points of many SPSs is available and PJM is gradually adding status points of others with the target of having all available.

TFCO members suggested that the CO-7 ad hoc group develop an operational checklist to follow for SPS monitoring. The C-43, "NPCC Operational Review for the Integration of New Facilities" document includes a checklist that can aid in the development of the SPS checklist.

9. Simultaneous Activation of Reserve (SAR) Training and Performance during Recent SAR Events

SAR Training

At the August TFCO meeting TFCO directed the CO-2 Working Group to focus the Fall 2012 System Operator Seminar training and table top exercise on Simultaneous Activation of Reserve (SAR) and the recent changes to Directory #5 "Reserve". That request was fulfilled at the Fall Seminar. Mike Potishnak, who was the principal presenter of the material and table top examples, summarized how the training went. The training material and examples addressed implementation of SAR, calculation and communication of SAR shares, interchange schedules and e-tags. Time was not sufficient to present the extensive material on SAR changes, SAR implementation details and Directory #5 changes plus examples. Twelve examples had been developed but time only allowed for presentation of two of them.

Some TFCO members commented on feedback from system operators who attended the seminar. There are still concerns that there is not a consistent understanding on how SAR shares are calculated and communicated, especially in

cases with wheeled energy. It is apparent that there is still the need for additional training regarding the details of application of SAR, especially for the radial source contingency events. It is estimated that only about one in seven SAR events have flawless execution. Each of the NPCC Reliability Coordinator and Balancing Authorities will use the seminar training material and examples and incorporate it into their operator training programs. They will emphasize the implementation of details. The Spring 2013 NPCC System Operator Seminar will again focus on SAR training and again use it as the Table Top exercise.

Performance during Recent SAR Events

Mike Potishnak discussed the detailed reports for recent SAR events.

There were 4 events in August:

- 8/5/12 New England event—This was a stressed system event. There was good SAR implementation performance.
- 8/7/12 New York event— Loss of 820 MW. The contingency for this SAR event was the loss of the Chateauguay connection at 782 MW due to a current transformer fire at Massena. Some participants were a little slow getting the shares in. There was good SAR implementation performance.
- 8/13/12 New York event—the contingency for this SAR event was the Chateauguay DC loss with a portion sinking in New England. It took over 5 minutes to implement the SAR share entry.
- 8/30/12 Ontario event—this was a gradual loss of capacity and not a DCS event.

There were 5 events in September:

- 9/5/12 event— Loss of 890 MW—this was a gradual loss of capacity and not a DCS event.
- 9/8/12 PJM event—Loss of 1,050 MW—this was a gradual loss of capacity and not a DCS event. There was late notification and late schedule and share entries.
- 9/8/12 New York event—Loss of 1,275 MW—there were some late schedule entries.
- 9/14/12 New England event—Loss of 1,061 MW—there was good SAR implementation performance.
- 9/20/12 New York event— Loss of 606 MW—there was good SAR implementation performance.

10. CIP-002-4 BES Cyber System Categorization

At the October TFCO meeting an action item called for the formation of the CO-7 ad hoc and that group work on identification of facilities that are subject to compliance assessment based on the CIP-002-4 cyber system categorization. Third party notifications in CIP-002-4's Criteria are needed to notify entities regarding applicability of standards to BES facilities. CIP-002 version 4 has 17 Criteria. The Entity (asset owner / operator) has information for 10 of these Criteria. For the remaining seven Criteria, the Entity depends on other Entities for "third party notifications."

As indicated in item 1, above, CO-7 ad hoc group is being formed with most members named. **Action Item: A draft letter will be prepared by the TFCO chair and NPCC staff to specify the expectations for the CO-7 regarding cyber system categorization of facilities for third party notifications for the CIP-002-4 standard.**

11. Identification of Load Associated with UFLS Programs and Manual Load Shedding Programs

Directory #2, "Emergency Operation", Appendix B, Item 4.3.2.1 indicates:

> "4.3.2.1 The first half of the **load** shed manually should not include load which is part of any automatic load shedding plan unless following manual **load shedding**, the requirements of Section 5.2.1 of this Directory can still be met."

An action item from the October TFCO meeting requested that each member check on the coordination between their manual and underfrequency load shedding. Members had checked and some had the programs coordinated and others did not. Those that did not will take action to provide coordination.

12. Status of NERC Activities

Most Recent Status on NERC Bulk Electric System (BES) Definition Group Activities

A "Bulk Electric System Guidance Document" was developed by the NERC BES Definition Drafting Team and was posted in October 2012. It provides many examples of system circuit configurations and indicates what instances would or would not be considered BES. It is meant to assist the industry with application of the BES definition exclusions.

Because New York and New England are under FERC jurisdiction they will directly follow the NERC BES bright line 100 kV and above definition with applicable exclusions. Each of the NPCC Canadian NPCC Areas is determining whether it will be applying the BES definition in the same manner as the U.S. entities. Quebec will be applying the NPCC BPS definition at the present time.

The Maritimes and Ontario are still evaluating and assessing the extent of exposure of their facilities under the NERC BES definition.

Balancing Authority Reliability-Based Control (BARC) Standard Drafting Team Meeting Highlights

The recent activities of the BARC group have involved the new BAL-012-1, "Operating Reserve Policy", BAL013-1, "Large Loss of Load Performance", and revised BAL-001-1, "Real Power Balancing Control" and BAL-002-1, "Disturbance Control Performance" standards.

- BAL012-1, "Operating Reserve Policy"—this addresses present day and next day planning of regulating, contingency, and frequency responsive reserve. This was developed based on a FERC directive. Item 4, "Applicability" addresses Reserve Sharing, Regulation Sharing and Frequency Response Sharing Groups. Requirement 8 calls for "each responsible entity to have a policy in place that requires the total capability of resources designated to provide reserves to be at least equal to the amount required to meet all reserve requirements concurrently prior to any need to deploy Regulating Reserve, Contingency Reserve or Frequency Responsive Reserve."
- BAL-013-1, "Large Loss of Load Performance"—the prospective BAL-013 standard deals with loss of large loads and is a mirror image of the BAL-002 Disturbance Control Performance Standard. It applies for 500 MW or larger loss of load, occurring within a rolling one minute interval based on EMS scan rate data.
- BAL-001-1—the revised content would consider more approaches to control SOLs without CPS2.
- BAL-002-1— the revised content drops CPS2 and has a frequency model similar to the Eastern Interconnection field trial.

Frequency Response Reliability-Based Control Standard Drafting Team July 17-20 Meeting Highlights

The latest on this is included in the BAL-003-1 item #5 above.

13. CO-10 Working Group Update on C-17, "Procedures for Monitoring and Reporting Critical Operating Tool Failures" Document Application and on Facilitated Transaction Checkout

De Tran, the new CO-10 chair, provided a presentation on critical operating tool failure analysis. It addressed several aspects of the CO-10 failure analysis work:

- Calculating the number of events per category and per sub-category
- Comparing results between categories and sub-categories

- Reviewing and analyzing the root cause of failures
- Sharing the lessons learned associated with the event
- Observing any trends or patterns

Results of the analysis work indicated:

- A total of **57** reportable events since December 2007
- A total of **10** reportable events from May 2011 to May 2012
- Tool failure Events
  - Most common category was problem with an application at 46%
  - Most common sub-category of application type was state estimators at 25%
- Contributing Factors
  - Most common category was vendor at 53%
  - Most common sub-category of vendor was EMS vendor at 29%

Observations on lessons learned and resulting recommended actions:

- Monitor EMS performance of the servers on a periodic basis to evaluate if the system is meeting the needs as designed and intended.
- Monitor disk storage space and alarming when disk storage is reaching capacity.
- Install a "watch dog timer" with an alarm to detect stale or stagnant data for the EMS and advanced applications (state estimator, contingency analysis, etc.)
- Manually failover from online to standby systems on a pre-scheduled periodic basis to test that it is functioning correctly prior to an automatic failover.
- 50 out of the 57 events reported under the C-17 Procedures for Monitoring and Reporting Critical Operating Tool Failures process would not have qualified as a reportable event under the NERC Events Analysis Process
- Seven reportable events since December 2007 would have qualified as a Category 2b in the NERC Events Analysis Process (complete loss of SCADA, control or monitoring functionality for 30 minutes or more)

14. TFCO Work Plan for 2012-2013 and Develop 2013-2014 Work Plan

The draft 2013-2014 TFCO Work Plan was presented to the RCC at the November 27, 2012 meeting and was approved.

15. TFCO Action Items

The action items from TFCO meetings will be issued to TFCO members very soon after meetings and before draft for comment minutes are issued so that all can follow up on the actions as soon as possible. Action items from this meeting and past meeting open items are included in Exhibit 2.

16.Verification of Actual Field Ratings vs. Design Ratings (FAC-003)-System Operation Effects

At the August 2012 TFCO meeting the group discussed Transmission Owner efforts to verify or revise facility ratings based on the FAC-003 standard requirements. That review indicated the need for many deratings of facilities or remediation efforts to maintain or upgrade ratings. Mike Schiavone indicated a concern that there have been some impacts to operations because of the rating revisions. He suggested that all NPCC Transmission Owners check on whether all facilities that could be considered BES based on the NERC definition have been evaluated for conductor clearances and rerated.

Prepared by Paul A. Roman
Draft for Comment minutes issued on January 4, 2012.
Final Minutes issued on January 23, 2013.

Exhibit 1
2013 Meetings RCC / TFCO / TFCO Working Groups / NERC

Date	Meeting	Location
JANUARY		
January 17-18, 2013	TFCO (January 17 8 AM-5 PM; January 18 8 AM-1 PM)	Montreal, Que.
FEBRUARY		
February 5-6, 2013	CO-8	New York, New York
February 14-15. 2013	CO-1	New York, New York
February 21-22, 2013	CO-10	New York, New York
February 27, 2013	RCC	New York, New York
February 28-March 1, 2013	CO-2	Montreal. Que.
MARCH		
March 4-7, 2013	NERC Events Analysis WG and NERC OC	Albuquerque, New Mexico
March 13-14, 2013	CO-11	Montreal. Que.
March 20-21, 2013	TFCO (March 20 8 AM-5 PM; March 21 8 AM-1 PM)	New York, New York-NPCC Offices
APRIL		
To be determined	CO-12	New York, New York
MAY		
May 1-2, 2013	CO-8	Boston, Ma.
May 8-9, 2013	Spring Operators Seminar	Saratoga Springs, NY
May 3, 2013	NPCC Media Teleconference	NPCC Board Room
May 15-16, 2013	TFCO (May 15 8 AM-5 PM; May 16 8 AM-1 PM)	Syracuse, New York
May 23-24, 2013	CO-1	Halifax, Nova Scotia
May 30-31, 2013	CO-10	Boston, Ma.
JUNE		

June 5, 2013	RCC	New York, New York
June 6-7, 2013	CO-11	New York, New York
June 10-13, 2013	NERC Events Analysis WG and NERC OC	Atlanta, Georgia
JULY		
AUGUST		
August 15-16, 2013	CO-10	Portland, Maine
August 28-29, 2013	TFCO (August 28 8 AM-5 PM; August 29 8 AM-1 PM)	Halifax, Nova Scotia
SEPTEMBER		
September 4-5, 2013	CO-11	Boston, Ma.
September 5-6, 2013	CO-1	Toronto, Ontario
September 11, 2013	RCC	New York, New York
September 12-13, 2013	CO-02	Halifax, Nova Scotia
September 16-19, 2013	NERC Events Analysis WG and NERC OC	Denver, Co.
September 24-25, 2013	CO-8	Montreal. Que.
OCTOBER		
October 17-18, 2013	TFCO (October 17 8 AM-5 PM; October 18 8 AM-1 PM)	Toronto, Ontario
To be determined	CO-12	New York, NY
NOVEMBER		
November 6-7, 2013	Fall Operators Seminar	Fredericton, NB
November 7-8, 2013	CO-10	Toronto, Ontario
November 19-20, 2103	CO-8	Toronto, Ontario
November 21-22, 2013	CO-11	Toronto, Ontario
DECEMBER		
December 3-4, 2013	RCC and General Meeting	Boston, Ma.

December 5-6, 2013	TFCO (December 5 8 AM-5 PM; December 6 8AM-1 PM)	Boston, Ma.
December 9-12, 2013	NERC Events Analysis WG and NERC OC	Atlanta, Georgia
December 12-13, 2013	CO-1	Montreal, Quebec

12/26/2012

Exhibit 2
TFCO Action Items-November 29-30, 2012 Meeting

FROM PAST MEETING-1. A presentation will be provided to TFCO on the July 15, 2012 Churchill Falls generator loss event once more information is provided by Churchill Falls Labrador Corporation, the owner of the Generators. Open

FROM PAST MEETING-2. Corrected data will be submitted for the July 15, 2012 SAR event and the event will then be re-reviewed. Open

FROM PAST MEETING-3. The NPCC Areas should make a summary of the facilities that apply for the CIP standards using the table provided by TFIST. At the October TFCO meeting TFCO will discuss the value of an NPCC guidance document to achieve consistency of application across NPCC. Open-Assigned as one of the items for the CO-7 ad hoc group.

FROM PAST MEETING 4. Keep the SMD item on future TFCO agendas. At the next New York City TFCO meeting Con Edison will arrange to have an SMD expert attend the meeting and provide a presentation. Open

5. Changes will be made to the TFCO exploder lists: 1) The tfco-all list will be eliminated, 2) The tfco-members list will include the TFCO members, alternates and regular participants and 3) TFCO correspondence that needs to go to others should have their addresses explicitly listed when sending e-mails. NPCC staff will make the changes.

6. The 2012 updated Facilities for Notification Lists will be posted on the access-restricted location on the NPCC web site. This location can be accessed on the CO-8 page. NPCC will post the updates and check the list to ensure only TFCO members and alternates, CO-8 members and alternates and PJM contacts can access this information.

7. RCs should notify neighboring systems if a Type I SPS is out of service. RCs should inform TFCO if there is any major SPS update.

8. TFCO members should identify specific design changes needed to achieve consistency with operations content in Directory 1. TFCO will establish contact with TFCP to notify them of TFCO operations section changes and the need to establish consistency between the design and operations sections of the document. Dwayne Basler will contact Brad Bentley, TFCP chair, to notify him of the TFCO intent.

9. A draft letter will be prepared by the TFCO chair and NPCC staff to specify the expectations for the CO-7 regarding cyber system categorization of facilities for third party notifications for the CIP-002-4 standard.

From:	Guy V. Zito
To:	rsc; tfss; tfsp
Subject:	Drafting Team for Project 2008-02 — Undervoltage Load Shedding — PRC-010 and PRC-022
Date:	Wednesday, February 13, 2013 9:30:34 AM
Attachments:	Project2008-02_SAR_UVLS_approved_2010Jan19.pdf
Importance:	High

To All,

NERC is reaching out and wants to solicit a member from NPCC for potential consideration to serve on the subject drafting team. UVLS and its associated standards are related to Blackout recommendations from the 2003 event and remain unresolved. NERC wishes to activate and aggressively pursue two standards in this regard. Please let me know if there are any individuals interested in serving on this team and being considered for appointment by the NERC Standards Committee. This is a potential two year commitment with perhaps a meeting every two months or so either by WebEx or in-person. The appointments will be made at the March 7-8 NERC Standards Committee meeting.

I have attached the approved SAR which, along with the existing standard filed and ruled on in Order 693, will be the initial guidance for the drafting team.

Please let me know if you have any questions and respond by the end of Feb.

Thanks,

Guy V. Zito
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212-840-1070
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