DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN

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SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN

In 2023, the 88th Texas Legislature enacted House Bill No. 2555 ("H.B. 2555"), now codified at Public Utility Regulatory Act ("PURA") § 38.078, to support Texas electric utilities making proactive investments to enhance the resiliency of their transmission and distribution systems. The Public Utility Commission of Texas ("Commission") implemented PURA § 38.078 by adopting 16 Texas Administrative Code ("TAC") § 25.62 (the "Resiliency Rule"). Southwestern Public Service Company ("SPS") hereby submits this Application for Approval of a System Resiliency Plan ("Application") pursuant to PURA § 38.078 and the Resiliency Rule. As detailed below, SPS's Application complies with the requirements of the Resiliency Rule.

I. INTRODUCTION

SPS serves approximately 280,000 homes and businesses in the Texas Panhandle and the Texas South Plains as a vertically integrated generation, transmission and distribution, and retail electric provider in the Southwest Power Pool. The Resiliency Rule recognizes, "[e]ach transmission and distribution system has different system characteristics and faces different resiliency events and resiliency-related risks" and the rule "provide[s] each utility with the flexibility to develop a well-tailored and systematic approach to improving the resiliency of its system."[1] SPS's expansive service area is largely rural, and its customer density is far less than many other Texas utilities, with a higher proportion of commercial and industrial ("C&I") load. SPS's service area is also unique in that it is completely encompassed by areas experiencing significantly increased wildfire risk over the last 50 years. SPS tailored its proposed resiliency

[1] 16 TAC § 25.62(a)(1).

investments to systematically address these unique system characteristics and the diverse resiliency risks that accompany them.

SPS's Application requests approval of a System Resiliency Plan ("SRP" or "Plan"), attached hereto as Attachment A, to enhance the resiliency of SPS's transmission and distribution systems in Texas (the "SPS System") that includes $538.3 million of investments tailored to the characteristics of its service area to be implemented in years 2025-2028. The Plan consists of five measures: (1) Distribution Overhead Hardening; (2) Distribution System Protection Modernization; (3) Communication Modernization; (4) Operational Flexibility; and (5) Wildfire Mitigation.

As encouraged by the Resiliency Rule, SPS engaged independent experts in resiliency and risk modeling — from 1898 & Co., the utility consulting division of Burns & McDonnell — to conduct a thorough analysis of the weather-based resiliency events that impact the SPS System to support development of this Plan. In addition, 1898 & Co. performed a benefit-cost analysis ("BCA") of the Distribution Overhead Hardening, Distribution System Protection Modernization, and Communication Modernization measures (excluding wildfire-specific aspects of these measures). 1898 & Co. evaluated the estimated costs and expected benefits of the potential projects to calculate a benefit-cost ratio ("BCR") for each measure, program, and project. Table 1 summarizes the BCA results for each measure and program that 1898 & Co. evaluated. The values in Table 1 include only the specific projects and investments that are proposed in the Plan and for which SPS seeks approval in this proceeding.

Table 1: Benefit-Cost Evaluation Summary[2]

Measure / Program	Avg. BCR	SRP Investment (2024$)	Benefits (2024$)	% Improvement in CMI
Distribution Overhead Hardening Measure (Distribution Circuit Hardening Rebuild Program)	4.7	$232.5M	$1,094.5M	58%
Distribution System Protection Modernization: Mainline Automated Reclosing Deployment Program	4.2	$79.7M	$333.0M	37%
Distribution System Protection Modernization: Lateral Reclosing Deployment Program	1.8	$2.0M	$3.5M	21%
Communication Modernization[3]	N/A	$104.6M	$104.6M	N/A
Total	**3.4**	**$418.8M**	**$1,431M**	**N/A**

As shown in Table 1, the overall BCR for the proposed investments evaluated by 1898 & Co. is approximately 3.4. This means that the investments proposed in the SRP will collectively provide customers with benefits 3.4 times greater than their costs. These benefits include significant reductions in customer outages—approximately 58% for circuits where hardening investment is made, 37% for circuits modernized under the mainline reclosing program, and 21% for circuits modernized under the lateral reclosing program.

SPS also engaged EDM International ("EDM"), a consulting firm specializing in wildfire mitigation, to help SPS assess wildfire risk to the SPS System and to develop a strategy for prioritizing programs to maximize wildfire mitigation. EDM also developed a geospatial Wildfire Risk Map of the SPS service area that allows SPS to visualize and understand the wildfire risk level across the different regions of its service area.

[2] Table 1 presents proposed SRP investments in 2024 dollars, as opposed to the SPS cost estimates presented in Table 4 below and in the SRP, which are nominal values that include annual escalation over the three-year investment period. As explained by Mr. De Stigter, 1898 & Co.'s Resilience & Risk Investment Model uses present values to make an apples-to-apples comparison between the present costs of investments against the present value of their benefits over a 50-year expected life.

[3] The Communication Modernization investment enables the full effectiveness of the Mainline Automated Reclosing Deployment program. Section 6.2.4.1 of the 1898 & Co. Report shows a BCR of 4.3 for the mainline automation program. The combined BCR for Communication Modernization and Mainline Automated Reclosing Deployment is 1.8.

The Commission's approval of this SRP will significantly enhance SPS's efforts to build a more resilient electric system and will benefit customers through a reduced frequency and duration of outages; avoided system restoration costs; improved overall reliability resulting from newly hardened and modernized infrastructure that is better equipped to withstand, mitigate, and more promptly recover from risks posed by extreme weather events, wildfires, and other threats; reduced wildfire ignition risk; and improved overall safety and system stability. SPS respectfully requests that the Commission approve its SRP, and the resiliency measures proposed therein, as well as SPS's request to defer the associated distribution costs to a regulatory asset for recovery in future ratemaking proceedings.

II. JURISDICTION AND AFFECTED PARTIES

SPS is a New Mexico corporation and a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy"). SPS is headquartered in Amarillo, Texas, and its business address is 790 S. Buchanan Street, 7th Floor, Amarillo, Texas 79101. SPS is a vertically integrated generation, transmission, and distribution utility that serves wholesale and retail electric customers in Texas and New Mexico.

SPS is a "public utility" as defined in PURA § 11.004(1) and an "electric utility" as defined in PURA § 31.002(6). As such, SPS's Texas operations are subject to the Commission's jurisdiction under PURA. The Commission has jurisdiction over this application under PURA §§ 14.001 and 38.078 and 16 TAC § 25.62. This application affects SPS and all of its Texas retail customers.

III. AUTHORIZED REPRESENTATIVES AND SERVICE OF DOCUMENTS

SPS's authorized representatives for this proceeding are:

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SPS requests that all documents (e.g., motions, orders, discovery requests, and discovery responses) be served on its authorized representatives.

IV. SUMMARY OF APPLICATION

A. Filing Overview

SPS's proposed Plan is Attachment A to this Application. SPS's Plan includes all of the information required by 16 TAC § 25.62(c) as outlined in more detail below.[4]

Consistent with 16 TAC § 25.62(d)(1), SPS's letters of notice to (1) all municipalities in SPS's service area that have retained original jurisdiction, (2) all parties in SPS's most recent base-rate proceeding, (3) the Office of Public Utility Council ("OPUC"), and (4) Southwest Power Pool are attached to this Application as Attachment B. Finally, SPS's proposed Protective Order is attached to this Application as Attachment C.

In further support of SPS's Application, the following SPS witnesses are filing direct testimony as described in Table 2 below.

[4] An application is sufficient if it includes the information required by subsection (c) of this section and the electric utility has filed proof that notice has been provided in accordance with this subsection. 16 TAC § 25.62(c).

Table 2 – SRP Direct Testimony and Sponsorship

Witness	Area of Testimony	Bates Page #	Sponsored SRP Section(s)
Adrian J. Rodriguez SPS President	Introduces and supports SPS's SRP; provides overview of SPS's service territory, customer makeup, and resiliency events that pose a risk to the SPS System; discusses SPS's approach to resiliency and the actions it is currently taking to advance resiliency of its system.	311	None
Brooke A. Trammell SPS Regional Vice President, Regulatory and Pricing	Supports SPS's SRP, including all measures and programs therein; presents budgeting for the SRP; discusses SRP cost recovery; explains and supports SPS's proposed tracking and accounting plan for SRP-related costs; discusses state and federal resiliency-related funding opportunities; describes SPS's proposed SRP evaluation metrics.	328	All Sections
Casey S. Meeks SPS Regional Vice President, Distribution Operations	Describes SPS's distribution system and specific factors connected to resiliency issues; explains the impact resiliency events have on SPS distribution system operations; discusses SPS's SRP implementation strategy.	372	Section III.C Section V
Brianne R. Jole Xcel Energy Services Inc. Manager, System Planning and Strategy, Distribution Integrated Planning	Describes SPS's coordination with 1898 & Co. in developing the SRP; introduces SRP measures; discusses SPS's current and ongoing approach to resilience and prioritization in SRP program selection; describes and supports the Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility SRP measures.	400	Section III Section IV.A Section IV.B Section IV.D
Wendall A. Reimer Xcel Energy Services Inc. Director II (IT) - Application Delivery, Technology Services	Supports the Communication Modernization measure; discusses migration of SPS's OT communications to a private LTE network; explains the resiliency benefits associated with the proposed private communications infrastructure.	445	Section II.C Section IV.C Section V
Jason D. De Stigter 1898 & Co. Director,	Introduces, summarizes, incorporates, and supports the Resilience Investment Study performed by 1898 & Co. for SRP	470	Section II.A

Witness	Area of Testimony	Bates Page #	Sponsored SRP Section(s)
Utility Investment Planning	development (the "1898 & Co. Report"); explains the methodology used by 1898 & Co. in its evaluation.		1898 & Co. Report (SRP Attachment A)
Anne Z. Sherwood Xcel Energy Services Inc. Area Vice President, Wildfire Mitigation: Regulatory and Policy	Supports and describes the Wildfire Mitigation measure; discusses wildfire risks within SPS's service area and SPS's current wildfire mitigation and risk assessment activities; describes SPS's engagement of outside expert consultants to advance wildfire-related resiliency.	520	Section IV.E Section V
Ryan Brockbank EDM International, Inc. Principal	Discusses and supports the Wildfire Mitigation measure; provides an explanation of wildfire risk mapping and SPS's Wildfire Operations Map.	545	Section II.B

B. SPS System and Service Area and Resiliency Events Affecting Them [16 TAC § 25.62(c)(2)(B)]

SPS serves approximately 52,000 square miles across Texas and New Mexico and 280,000 homes and businesses in the Texas Panhandle and Texas South Plains. Much of SPS's service area is rural but interspersed with sizable population centers, like Amarillo. The load on the SPS System is predominantly commercial and industrial. Due to the largely rural character of SPS's expansive service area, SPS's customer density is far less than many other Texas utilities. Functionally, this means SPS has fewer customers per mile of distribution line than many other utilities in the State.

The weather in SPS's service area in Texas can be violent and variable. SPS's service area can experience weather events ranging from icing and blizzards to extreme heat and drought, flooding, high winds, and tornadoes. High winds and winter weather have the greatest impact on the SPS System and customers. High winds account for nearly 70% of all outages from 2010 through 2023, and over 45% of Customer Minutes Interrupted ("CMI") over that same period. Winter weather accounts for 8.5% of outages during that period, but its per-outage impact is much higher, accounting for over 50% of CMI during that time frame.

In addition to the direct impacts of these weather events to the SPS System, some events also increase the likelihood of wildfires. SPS's service area is completely encompassed by areas experiencing significantly increased wildfire risk over the last 50 years. The predominant fuels in

the region are finer fuels such as grasses and small woody shrubs that are highly susceptible to fire risk during dry, windy conditions. And as extreme weather conditions become more frequent, SPS must prepare for increasing wildfire activity.

Consistent with 16 TAC § 25.62(c)(2)(B), SPS's Plan (1) identifies and describes each type of resiliency event and related risks the Plan is designed to address, (2) includes magnitude thresholds where appropriate, (3) describes the SPS System characteristics that make it susceptible to identified resiliency events, and (4) provides evidence to support the presence of and risks posed by the identified resiliency events.

C. SPS's System Resiliency Plan Overview [16 TAC § 25.62(c)(1) and (c)(2)(A)]

As required by 16 TAC § 25.62(c)(2), SPS has organized its SRP by measure and proposes five measures — (1) Distribution Overhead Hardening, (2) Distribution System Protection Modernization, (3) Communication Modernization, (4) Operational Flexibility, and (5) Wildfire Mitigation — each with a number of new or expanded programs and activities designed to address one or more resiliency events that pose a material risk to the safe and reliable operation of the SPS System. Each proposed measure uses at least one of the methods set forth in PURA § 38.078(b) and 16 TAC § 25.62(c)(1).

Further, consistent with PURA § 38.078 and 16 TAC § 25.62(c)(2)(A), SPS's Plan (1) explains SPS's prioritization of identified resiliency events, the particular geographic area, system, or facilities where measures will be implemented; (2) includes evidence of the effectiveness of the measures; (3) explains the expected benefits of the resiliency measures including but not limited to, reduced system restoration costs and reduction in the frequency of outages for customers; (4) identifies if a resiliency measure is part of a coordinated effort with federal, state, or local government programs or may benefit from federal, state, or local government funding opportunities; (5) explains the selection of a particular measure over any reasonable and readily identifiable alternatives; and (6) identifies any measures that may require a transmission system outage to implement.

Additional detail on each measure is provided in the direct testimonies of their sponsoring witnesses, Brianne Jole, Casey Meeks, Wendall Reimer, and Anne Sherwood. The measures, associated program activities, and resiliency event categories mitigated are summarized as follows.

Table 3 – SRP Measures & Programs

Measure	Measure Program Activities	Resiliency Event Category Mitigated
Distribution Overhead Hardening	• Pole Replacements/Installations • Conductor Replacements • Line Transformer Replacements • Pole Wraps in High Wildfire Risk Areas • Pole Trussing	Wind, Flood, Tornado, Winter, Heat, Cold and Wildfire
Distribution System Protection Modernization	• Program 1 – Mainline Automated Reclosing Deployment o New Mainline Automated Reclosers o Existing Recloser Replacements & Communication Installation, o Substation Relay Panel Replacements and Substation Breaker Replacements, o Fault Indicator Installations, o Tap Fuse Replacements • Program 2 – Lateral Reclosing Deployment o Lateral Recloser Installations	Wind, Flood, Tornado, Winter, Heat, Cold and Wildfire
Communication Modernization	• Private LTE towers • Fiber Optic Cable on Transmission Lines • Additional Remote Terminal Units at Substations	Wind, Flood, Tornado, Winter, Heat, Cold, Wildfire, and Cybersecurity
Operational Flexibility	• Program 1 – Mobile Substation Equipment o Mobile Substations o Regulator Trailer o Circuit Switcher Trailer • Program 2 – Installation of Transmission Switches o Loadbreak and non-loadbreak switches	Wind, Flood, Tornado, Winter, Heat, and Cold
Wildfire Mitigation	• Program 1 – Situational Awareness o Weather Stations o AI Cameras o Best-in-class Weather and Fire Science Modeling Software • Program 2 – Physical Mitigation o Poles with enhanced vegetation management o Wood Substation Conversions o Detailed Inspections in wildfire areas	Wildfire

The total estimated capital cost of the SRP is $521.5 million, and the incremental operating expenses are $16.8 million. Table 4 below provides a summary of the estimated capital costs, incremental expenses, and implementation timelines for each proposed measure.

Table 4 – Implementation Timeline and Estimated Costs

Measure	Implementation Timeline	Estimated Spend (in $Millions)
Distribution Overhead Hardening	2025	Capital: $19.5 O&M: 0
	2026	Capital: $56.1 O&M: 0
	2027	Capital: $75.7 O&M: 0
	2028	Capital: $101.7 O&M: 0
Distribution System Protection Modernization	2025	Capital: $8.1 O&M: 0
	2026	Capital: $19.4 O&M: 0
	2027	Capital: $28.3 O&M: 0
	2028	Capital: $36.5 O&M: 0
Communication Modernization	2025	Capital: 0 O&M: 0
	2026	Capital: $34.2 O&M: 0
	2027	Capital: $37.1 O&M: 0
	2028	Capital: $41.4 O&M: 0
Operational Flexibility	2025	Capital: $3.1 O&M: 0
	2026	Capital: $10.1 O&M: 0
	2027	Capital: $23.8 O&M: $0.002
	2028	Capital: $6.7 O&M: $0.004
Wildfire Mitigation	2025	Capital: $2.5 O&M: $2
	2026	Capital: $7.6 O&M: $4.5
	2027	Capital: $8 O&M: $5.2

Measure	Implementation Timeline	Estimated Spend (in $Millions)
	2028	Capital: $1.7 O&M: $5.1
	Total:	**Capital: $521.5** **O&M: $16.8**
	Grand Total:	**$538.3**

D. Evaluation Metrics and Criteria [16 TAC § 25.62(c)(2)(C)]

Section 25.62(c)(2)(C) of the Resiliency Rule requires each SRP to include metrics or criteria for evaluating the effectiveness of each measure in preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the resiliency event it is designed to address. SPS is proposing evaluation metrics and criteria, which are detailed in Section V of the SRP and in the direct testimonies of SPS witnesses Ms. Trammell providing an introduction to metrics, Mr. Meeks regarding Overhead Hardening, Distribution System Protection Modernization and Operational Flexibility, Mr. Reimer regarding Communication Modernization, and Ms. Sherwood regarding Wildfire Mitigation. Further, each resiliency measure under Section IV of the Plan includes a subsection dedicated to applicable metrics. The following table summarizes SPS's proposed metrics.

Table 5 – SRP Metrics

Metric	Distribution Overhead Hardening	Distribution System Protection Modernization	Communication Modernization	Operational Flexibility	Wildfire Mitigation
Underperforming Area Count	X	X	X		
Rolling 10-Year Average SAIDI	X	X	X	X	
Storm Restoration Duration	X	X	X		
Average Hardened Protection Zone (AHPZ) CI vs Average Protection Zone (APZ) CI Comparison by County (Hardened Only)	X				
AHPZ CI Percentage Improvement	X				
RAN Tower Completion			X		
End Device Connectivity			X		
Units Completed in DSAP					X
Transmission Inspections					X

The respective testimonies explain the appropriateness of the selected evaluation metric for each resiliency measure. SPS developed its proposed metrics to provide a quantitative assessment of the effectiveness of the resiliency measures proposed in this SRP. Finally, the Plan includes an analysis of the expected effectiveness of the selected metrics as discussed below.

E. Evidence of Effectiveness and Benefits [16 TAC § 25.62(c)(2)(C)(iii)]

SPS retained independent entities with relevant expertise to provide quantitative and/or performance-based evaluations of SPS's proposed resiliency measures. To assess the risks posed by weather-based resiliency risks, SPS contracted with 1898 & Co., a consulting engineering firm with extensive expertise in the electrical industry, including experience modeling resiliency risks and investments. 1898 & Co. personnel coordinated with SPS to assist in the design of the proposed measures, model the resiliency risks to the SPS System, and provide evidence of the expected benefits for the proposed SRP measures. 1898 & Co. performed a quantitative benefit-cost analysis for three of SPS's Plan measures. The result of 1898 & Co.'s assessment is the 1898 & Co. Report, included as Attachment A to the SRP. As SPS witness Jason De Stigter discusses, the 1898 & Co. Report shows that SPS's SRP will provide direct, quantifiable benefits to SPS customers in the form of reduced frequency and duration of outages and reduced outage-restoration costs. As an example, the lowest benefit-cost ratio of any project included in the Distribution Overhead Hardening measure is 3.22. This means that these projects will provide at least three times the economic benefit to customers as the cost to implement the project.

SPS contracted with EDM International, a consulting firm with extensive experience performing wildfire-risk modeling and assessment for electric utilities, to conduct a performance-based analysis of SPS's Wildfire Mitigation measure and create a Wildfire Operations Map specific to SPS's service territory. As discussed in Sections II.B and IV.E of the Plan and the direct testimony of SPS witness Ryan Brockbank, EDM's analysis demonstrates that improved situational awareness, grid hardening, and other pre-planning to help reduce the negative impacts to SPS customers and stakeholder from resiliency events are consistent with leading utility practice and regulator expectations.

Together, the 1898 Report and EDM analysis provide evidence of the effectiveness and benefits of SPS's proposed resiliency measures. SPS proposes use of metrics in evaluating the effectiveness of the measures in the SRP, as discussed in the direct testimonies of SPS witnesses Mr. Meeks regarding Overhead Hardening, Distribution System Protection Modernization and Operational Flexibility, Mr. Reimer regarding Communication Modernization, and Ms. Sherwood regarding Wildfire Mitigation.

F. Systematic Implementation Approach [16 TAC § 25.62(c)(2)(D), (c)(2)(E), and (c)(2)(F)]

SPS's Plan includes entirely incremental work. To the extent the Plan programs are similar to existing programs, the Plan appropriately delineates the two and explains coordination with existing programs, pursuant to 16 TAC § 25.62(c)(2)(D).

SPS has developed a systematic implementation approach to prioritize investments in this SRP, consistent with 16 TAC § 25.62(c)(2)(E). SPS ultimately selected the measures, programs, and projects presented in this SRP based on several objectives, including: (1) mitigating the impacts of resiliency events with the greatest impacts on the SPS system and its customers, as determined by SPS's operational experience and the 1898 & Co. analysis; (2) furthering SPS's long-term resiliency objectives, including mitigating wildfire risks and modernizing system protection capabilities; (3) leveraging the BCR, which accounts for the historical performance of the system during resiliency events; and (4) optimizing the overall size of the Plan, with consideration for the costs to customers and SPS's ability to execute on the full portfolio of proposed investments between 2025 and 2028.

Ms. Jole's direct testimony describes SPS's prioritization framework and systematic implementation approach in more detail. Mr. DeStigter describes the results of 1898 & Co.'s analysis, as summarized in Table 6, in more detail in his direct testimony.

Table 6: Benefit-Cost Evaluation Summary[5]

Measure / Program	Avg. BCR	SRP Investment (2024$)	Benefits (2024$)	% Improvement in CMI
Distribution Overhead Hardening Measure (Distribution Circuit Hardening Rebuild Program)	4.7	$232.5M	$1,094.5M	58%
Distribution System Protection Modernization: Mainline Automated Reclosing Deployment Program	4.2	$79.7M	$333.0M	37%
Distribution System Protection Modernization: Lateral Reclosing Deployment Program	1.8	$2.0M	$3.5M	21%
Communication Modernization[6]	N/A	$104.6M	$104.6M	N/A
Total	**3.4**	**$418.8M**	**$1,431M**	**N/A**

As shown in Table 6, the overall BCR for the investments evaluated by 1898 & Co. is approximately 3.4. These investments also show a significant improvement in customer outages, approximately 58% for those circuits where hardening investment is made and approximately 37% for mainline automation.

Mr. Meeks describes how SPS will procure the contract resources and materials required to execute its systematic implementation approach over a three-year period, as well as how SPS will comply with the reporting requirements of the Resiliency Rule. Finally, Ms. Trammell explains how SPS will account for and track its SRP-related investments, as well as SPS's intention to defer recovery of its resiliency-related distribution costs as a regulatory asset for recovery in future ratemaking proceedings.

[5] Table 6 presents the total proposed SRP investment in 2024 dollars as opposed to the cost estimates SPS presents in Table 4 above and the SRP, which are nominal values that include annual escalation over the three-year investment period. As explained by Mr. DeStigter, 1898 & Co.'s Resilience & Risk Investment Model uses present values to make an apples-to-apples comparison of the present costs of investments against the present value of their benefits over a 50-year expected life.

[6] The Communication Modernization investment enables the full effectiveness of the mainline automated reclosing deployment program. Section 6.2.4.1 of the 1898 & Co. Report showed a BCR of 4.3 for the mainline automation program. The combined program BCR is 1.8.

SPS will need to deviate from any approved implementation schedule if the Southwest Power Pool has not approved an outage that would be required to timely implement the Plan, pursuant to 16 TAC § 25.62(c)(2)(F).

G. Plan Executive Summary [16 TAC § 25.62(c)(2)(G)]

SPS's Plan includes an Executive Summary at Section I, and a comprehensive chart as Attachment B to the Plan, that explains the Plan's objectives, the resiliency events or related risks the Plan is designed to address, the Plan's measures, the proposed metrics for evaluating the Plan's effectiveness, the Plan's cost and benefits, and an explanation of how the overall Plan is in the public interest.

V. RELIEF REQUESTED

Based on this Application and supporting evidence, including the SRP, the SRP's attachments, and testimony, SPS respectfully requests that the Commission:

i. find SPS's proposed SRP is in the public interest and compliant with 16 TAC § 25.62, and approve it;

ii. authorize SPS to implement the SRP through 2028 or at least three years after any approval of this SRP, whichever is later, unless SPS requests to amend the SRP with the amendment to take effect no later than three years from an approval of this SRP;

iii. approve SPS's requested flexibility in implementation as described in the SRP;

iv. authorize SPS to establish a regulatory asset to capture distribution-related costs related to the implementation of the SRP;

v. authorize a twelve-month amortization period for the regulatory asset as requested in (iii);

vi. authorize SPS to defer all costs associated with the preparation and defense of this application;

vii. approve SPS's proposed metrics as stated in the SRP; and

viii. grant all other relief the Commission deems necessary or appropriate.

VI. NOTICE

SPS is providing notice of this Application pursuant to PURA § 38.078(e) and 16 TAC § 25.62(d)(1). Notice is being provided to: (1) all municipalities in SPS's service area that have retained original jurisdiction; (2) all parties in SPS's most recent base-rate proceeding; (3) OPUC; and (4) Southwest Power Pool. SPS's letters of notice, pursuant to the Resiliency Rule, are attached to this application as Attachment B. In accordance with 16 TAC § 25.62(d)(1), the intervention deadline in this proceeding will be January 30, 2025, 30 days after service of notice is complete.

VII. MOTION FOR ENTRY OF A PROTECTIVE ORDER

SPS expects that it may need to provide in testimony, workpapers, or responses to discovery requests confidential or highly sensitive information the disclosure of which to third parties would either place SPS at a severe competitive disadvantage or cause SPS to violate contractual confidentiality obligations. Accordingly, SPS is attaching a proposed protective order to this application as Attachment C, which will facilitate parties' access to the confidential or highly sensitive material while protecting the interests of SPS and the third parties to whom SPS owes confidentiality obligations.

The proposed protective order is substantially the same as the Commission's standard protective order and the protective order approved in Docket No. 54634, SPS's most recent base rate case.[7] SPS requests that the Commission enter a protective order in the form attached to this application as Attachment C. SPS further proposes that, pending entry of the protective order, the parties agree to treat the proposed protective order as a confidentiality agreement.

VIII. CONCLUSION

SPS's SRP is a comprehensive and evidence-based plan developed in collaboration with third-party experts to address the specific needs of its customers, given the unique characteristics of SPS's Texas service area. The Plan utilizes decades of quantitative, qualitative, and historical data to prioritize risks by events and geography and recommends targeted investments to reduce

[7] Docket No. 54634, Order No. 1 at 2 (Mar. 6, 2023).

the impact of severe weather events and wildfire. The 1898 & Co. analysis finds that — exclusive of qualitative and wildfire-related benefits — the Distribution Overhead Hardening, Distribution System Protection Modernization, and Communication Modernization measures SPS SRP present an enormous opportunity for SPS to cost-effectively strengthen its system and make it more resilient for its customers and communities. EDM concluded that the measures proposed represent leading utility wildfire management strategies.

For the reasons stated in this Application, the Plan, the Plan's attachments, and the supporting testimony and exhibits, SPS asks the Commission to (i) find SPS's proposed SRP is in the public interest and compliant with 16 TAC § 25.62, and approve it; (ii) authorize SPS to implement the SRP through 2028 or at least three years after any approval of this SRP, whichever is later, unless SPS requests to amend the SRP with the amendment to take effect no later than three years from an approval of this SRP; (iii) approve SPS's requested flexibility in implementation as described in the SRP; (iv) authorize SPS to establish a regulatory asset to capture distribution-related costs related to the implementation of the SRP; (v) authorize a twelve-month amortization period for the regulatory asset requested in (iii); (vi) authorize SPS to defer all costs associated with the preparation and defense of this application; (vii) approve SPS's proposed metrics as stated in the SRP; and (viii) grant all other relief the Commission deems necessary or appropriate.

Respectfully Submitted,



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Xcel Energy®
SYSTEM RESILIENCY PLAN
Southwestern Public Service Company
December 31, 2024

System Resiliency Plan

Southwestern Public Service Company

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I. EXECUTIVE SUMMARY

A. Overview of the Filing

Southwestern Public Service Company ("SPS") appreciates the opportunity to present its first System Resiliency Plan ("SRP" or "the Plan") designed to enhance the resiliency of its Texas transmission and distribution systems ("SPS System") consistent with Public Utility Regulatory Act ("PURA") § 38.078 and 16 Texas Administrative Code ("TAC") § 25.62 (the "Resiliency Rule").

This Plan will benefit SPS customers and promote the public interest through reduced frequency of power outages and outage times; cost savings from decreased storm recovery costs and expensive emergency repairs; a hardened infrastructure and equipment to withstand weather events and other threats; improved overall safety, reliability and system stability; and a more modern and flexible system that can better serve our customers. It also includes specific investments addressing wildfire risk and upgrading communication capabilities for protection, response, and recovery.

SPS's filing requests approval of $538.3 million of investments to be implemented in years 2025-2028 through the following measures:

- **Distribution Overhead Hardening**
  - *Targeted circuit hardening and rebuilds: replacing and reinforcing distribution poles, replacing conductor, line transformers, and open-wire secondary, mitigating long span lengths, and, in high wildfire risk areas, wrapping poles with fire resistant coatings and replacing arrestors and transformer fuses with non-expulsion alternatives.*
- **Distribution System Protection Modernization**
  - *Optimizing protection schemes with new equipment, including sectionalizing reclosers, mid-point (tie) reclosers,*[1] *communications equipment, updated substation relay panels and breakers, and, in high wildfire risk areas, fault current indicators and non-expulsion fuse alternatives*

[1] Throughout this plan, testimony, and the 1898 & Co. Report, mid-point (tie) reclosers are sometimes referred to simply as tie reclosers. These are the same products and will be deployed consistent with the SPS Operating Manual.

- **Communication Modernization**
    - *Building out a Private LTE network, installing fiber optic cable on select transmission lines, and adding remote terminal units at substations, which will help enable the benefits of the distribution modernization measure.*
- **Operational Flexibility**
    - *Procuring mobile substation equipment and installing additional switching devices on select transmission circuits.*
- **Wildfire Mitigation**
    - *Acquiring weather stations to enhance SPS's meteorological capabilities, adopting weather and fire science modeling, deploying artificial intelligence ("AI") cameras to more effectively detect wildfire threats, vegetation management to create defensible spaces around structures, wood substation conversions, and detailed visual inspections.*

Below, SPS discusses the resiliency risks experienced in its service area, how SPS analyzed those risks and potential measures to mitigate them, and the measures ultimately selected for proposal in this SRP. SPS also discusses how these measures benefit its customers and the public interest and provides the metrics to evaluate their effectiveness going forward.

B. Resiliency Risks in SPS's Service Territory

SPS is a wholly owned electric utility subsidiary of Xcel Energy, Inc., headquartered in Amarillo, Texas. SPS serves approximately 52,000 square miles across its Texas and New Mexico service territory and 280,000 homes and businesses in the Texas Panhandle and Texas South Plains as a vertically integrated generation, transmission and distribution, and retail electric provider in the Southwest Power Pool (outside of the Electric Reliability Coordinating Council of Texas). Much of SPS's service area is rural but interspersed with sizable population centers, like Amarillo. The load on SPS's System is predominantly commercial and industrial. Due to the largely rural character of SPS's expansive service area, SPS's customer density is far less than many other Texas utilities. Functionally, this means that SPS has fewer customers per mile of distribution line than many other utilities in the State.

Texas Panhandle weather is variable and can be violent. SPS's service area can experience weather events ranging from icing and blizzards, to extreme heat and drought, flooding, high winds, and tornadoes. As shown in the figures below, high winds and winter weather have the

greatest impact on SPS's system and customers. High winds account for nearly 70 percent of all outages from 2010 through 2023, and over 45 percent of "Customer Minutes Interrupted" or "CMI" over that same period. While winter weather accounts for 8.5 percent of outages during that period, its per-outage impact is much higher, accounting for over 50 percent of CMI during that time frame.

Figure 1 – Mapped CMI to NOAA Events

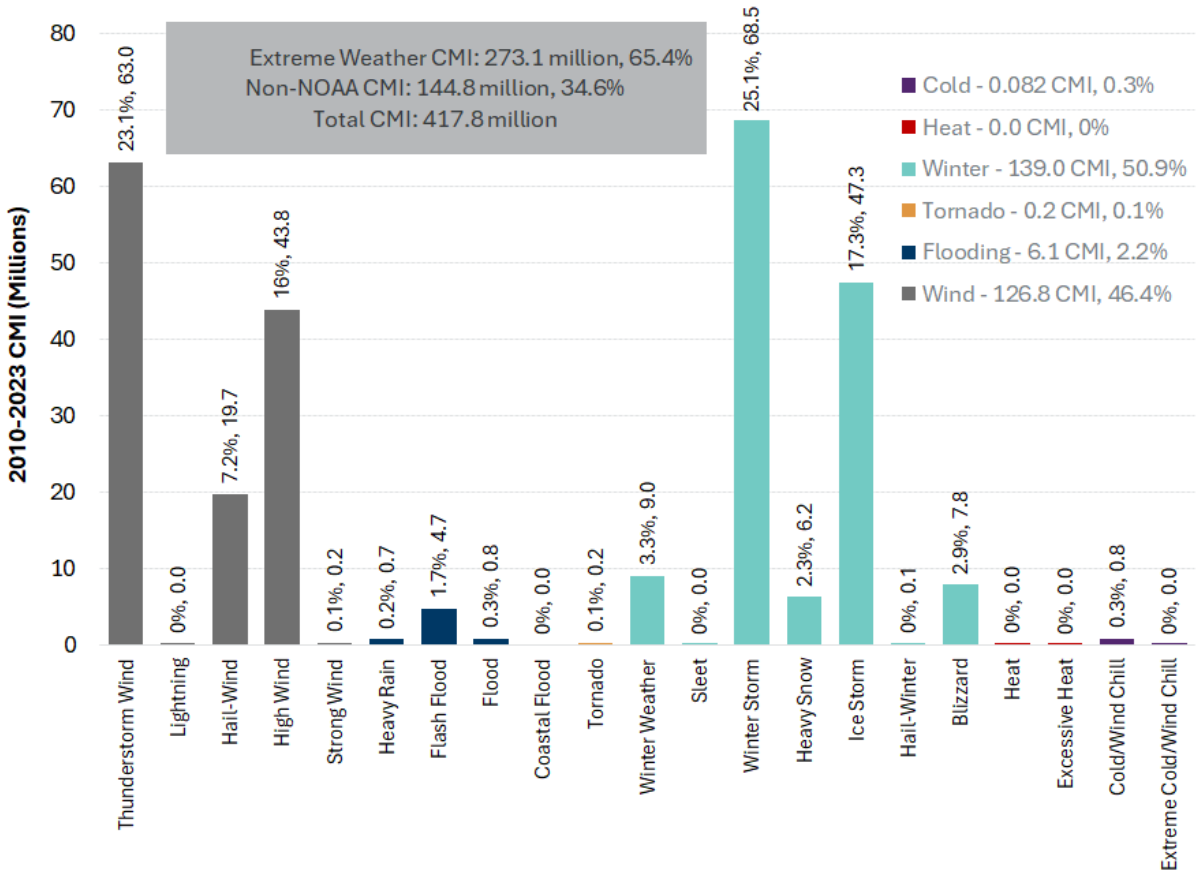
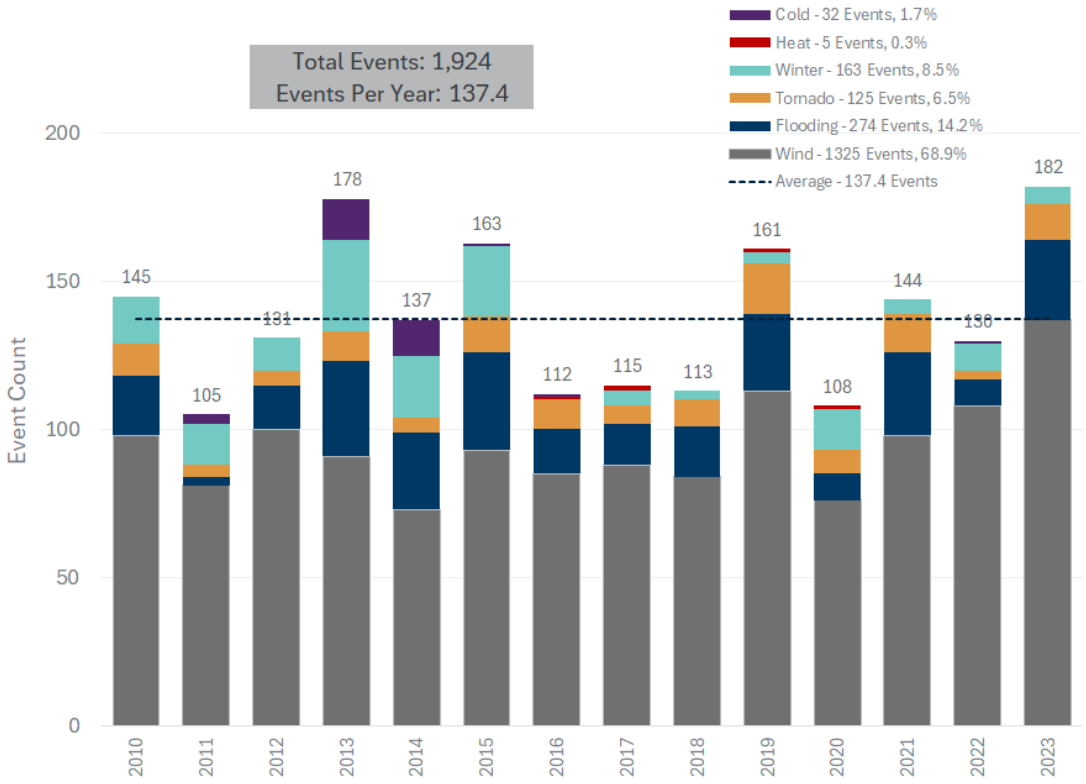


Figure 2 – NOAA Events Identified in SPS's Outage Records (2010-2023)



In addition to the direct impacts of these weather events to the SPS System, some events also increase the likelihood of wildfires. SPS's service area is completely encompassed by areas experiencing significantly increased wildfire risk over the last 50 years. The predominant fuels in the region are finer fuels such as grasses and small woody shrubs that during dry, windy conditions are highly susceptible to fire risk. And as extreme weather conditions become more frequent, SPS must prepare for increasing wildfire activity.

C. Method of Determining SRP Programs and Measures

The Resiliency Rule encourages utilities to work with independent consultants to develop and evaluate measures proposed within the SRP. SPS engaged 1898 & Co. to conduct a thorough analysis of weather and other resiliency events that impact SPS's Texas service area, to support development of this Plan. SPS and 1898 & Co. collaborated on measures focused on weather-based resiliency, including investment activities to support wildfire resiliency. 1898 & Co. performed a cost benefit analysis of the Distribution Overhead Hardening, Distribution System

Protection Modernization, and Operational Flexibility SRP measures based on the estimated costs of the projects and a benefit-cost ratio ("BCR") analysis.

1898 & Co. utilized a resilience and risk-based planning approach to identify, prioritize, and perform benefit modeling to support the development of the SRP. The resilience and risk-based planning approach utilizes a suite of planning models that collectively comprise the Integrated Resilience and Risk Investment Model. The 1898 & Co. model includes foundational data, including a catalogue of the historical resiliency events that impacted the SPS System and information from SPS's asset register, including equipment age and characteristics, to determine the unique vulnerabilities of SPS's System. The model's actionable investment activities prioritize resilience and risk-based investments based on available data, analytics models, and benefit-cost analyses.

This approach calculates the resilience and risk improvement at the investment activity, program, protection zone, and measure levels. Resilience and risk benefits for resilience investment activities are estimated from a customer-centric perspective in alignment with subsection (c)(2)(A)(iii) of the Resiliency Rule. The customer benefits are shown in terms of the decrease in utility restoration costs, the decrease in the number of customers impacted, and the duration of the overall outage. The results of 1898 & Co.'s modeling are shown in Table 1 below, with the Distribution System Protection Modernization measure showing the highest average BCR at 3.0, and the Communication Modernization measure showing the lowest average BCR at 1.8.

Table 1: Benefit-Cost Evaluation Summary Table[2]

Measure / Program	Avg. BCR	SRP Investment (2024$)	Benefits (2024$)	% Improvement in CMI
Distribution Overhead Hardening Measure (Distribution Circuit Hardening Rebuild Program)	4.7	$232.5M	$1,094.5M	58%
Distribution System Protection Modernization: Mainline Automated Reclosing Deployment Program	4.2	$79.7M	$333.0M	37%
Distribution System Protection Modernization: Lateral Reclosing Deployment Program	1.8	$2.0M	$3.5M	21%
Communication Modernization[3]	N/A	$104.6M	$104.6M	N/A
Total	**3.4**	**$418.8M**	**$1,431M**	**N/A**

SPS also engaged EDM International ("EDM") a consulting firm specializing in wildfire mitigation to help SPS assess wildfire risk to the SPS System and to develop a strategy for prioritizing programs that would maximize wildfire mitigation. EDM developed a geospatial Wildfire Risk Map[4] of the SPS service area that allows SPS to visualize and understand the wildfire risk level across the different regions of its service area. Figure 3 below depicts the wildfire threat levels within SPS's service area. The map depicts the threat level by tiers, with Tier 1 representing

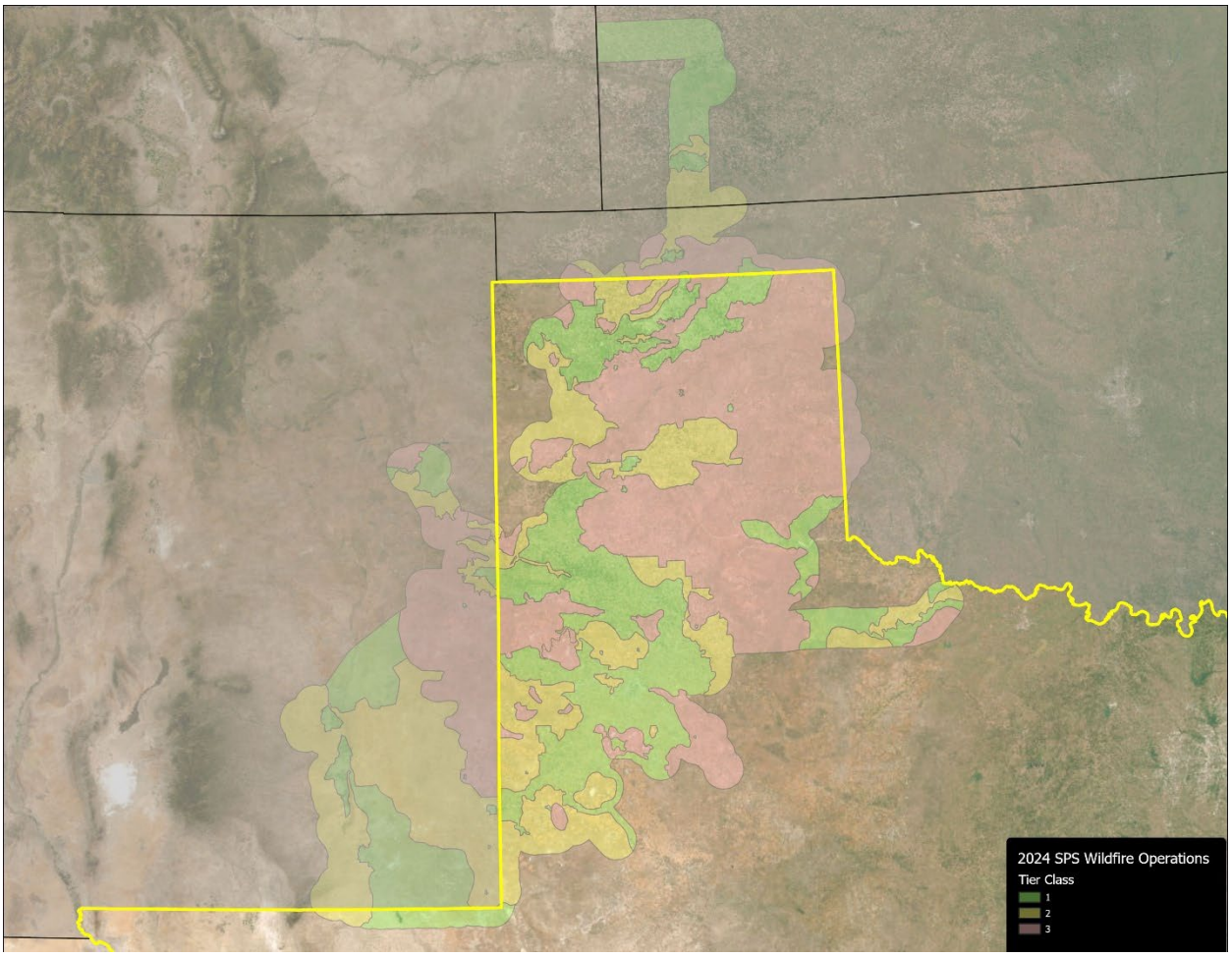
[2] Table 1 presents proposed SRP investments in 2024 dollars, as opposed to the SPS cost estimates presented in Attachment B, which are nominal values that include annual escalation over the three-year investment period. As explained by Mr. De Stigter, 1898 & Co.'s Resilience & Risk Investment Model uses present values to make an apples-to-apples comparison between the present costs of investments against the present value of their benefits over a 50-year expected life.

[3] The Communication Modernization investment enables the full effectiveness of the Mainline Automated Reclosing Deployment program. Section 6.2.4.1 of the 1898 & Co. Report shows a BCR of 4.3 for the mainline automation program. The combined BCR for Communication Modernization and Mainline Automated Reclosing Deployment is 1.8.

[4] In general, the terms Wildfire Risk Map and Wildfire Operations Map are used interchangeably in this SRP and direct testimony.

areas of low wildfire risk, Tier 2 representing areas of moderate wildfire risk, and Tier 3 representing areas of high wildfire risk.

Figure 3 – SPS Wildfire Risk Map



This analysis evaluates the landscape wildfire risk relative to populated areas and developed assets in SPS's service territory to assist SPS with the prioritization and operationalizing of wildfire risk mitigation efforts. This approach prioritizes system vulnerabilities and weather-based resiliency events with the highest likelihood of occurrence. For example, as shown in the 1898 & Co. Report, over 85 percent of the distribution overhead hardening and distribution system protection modernization measures will be focused on areas of SPS's system with the highest wildfire risk.

D. Programs and Measures

SPS's SRP is organized into five measures: (1) Distribution Overhead Hardening, (2) Distribution System Protection Modernization, (3) Communication Modernization, (4) Operational Flexibility, and (5) Wildfire Mitigation. Table 2 below shows the various programs and activities planned and the total budget that SPS has allocated to each measure. More detailed budget information is included in the program descriptions under each relevant measure in Section IV.

SPS ultimately selected the measures and programs proposed in this SRP based on several factors, including (1) mitigating the effects of resiliency events that impact the SPS System; (2) leveraging the BCR as reported by 1898 & Co., which incorporates the historical performance of feeders in the analysis; and (3) optimizing the overall size of the SRP, with consideration for the costs to customers and SPS's ability to execute on the full portfolio of proposed investments in years 2025-2028. SPS proposes to prioritize investments considering the wildfire risk in the area, as determined by the Wildfire Risk Map developed in coordination with EDM, and the BCR, as determined by 1898 & Co.'s analysis. The BCR values associated with projects are derived, in large part, from the historical performance of SPS's facilities during resiliency events.

The proposed measures in the Plan include new or expanded programs and activities to mitigate the effects of resiliency events that pose a material risk to the safe and reliable operation of the SPS System and are distinguishable from existing programs and activities. A summary of the activities and programs within each measure, the resiliency events to be mitigated by each proposed measure, and the estimated capital investment and O&M expenses for each measure is presented in Attachment B ("Summary Table").

E. Expected Benefits and Proposed Metrics

SPS engaged 1898 & Co. to analyze and quantify the expected benefits of certain of the resiliency measures proposed in this SRP, which are described in greater detail in the 1898 & Co. Report (attached hereto as Attachment A). 1898 & Co. used a resilience and risk-based planning approach to identify and prioritize distribution system resiliency investments utilizing an Integrated Resilience & Risk Investment Model developed by 1898 & Co. 1898 & Co. performed the resiliency benefit-cost analysis for resilience investment activities and estimated their

quantifiable benefits for the following SPS measures: (1) Distribution Overhead Hardening; (2) Distribution System Protection Modernization; and (3) Communication Modernization. SPS's Plan also includes Operational Flexibility and Wildfire Mitigation measures, which were not evaluated by 1898 & Co. but are addressed in other parts of SPS's filing.

The Distribution Overhead Hardening measure is designed to mitigate resiliency events that pose a risk to infrastructure structural vulnerabilities, including wind, tornado, and winter events. Hardened facilities will provide significant improvement for customers as hardened facilities will fail less frequently, allowing crews to restore the system more quickly. Quantified benefits for the measure are shown in terms of avoided restoration costs and from avoided customer outages.

The Distribution System Protection Modernization measure includes investment to minimize the impact of disruptive weather-based events. Distribution System Protection Modernization changes the number of customers impacted by the same infrastructure failures and leads to a benefit of reduced or avoided customer outages. Specifically, (a) it provides additional sectionalization of circuit mainlines so that fewer customers experience an outage when an event occurs on the circuit mainline; (b) automated feeder transfer schemes minimize customer downtime during disruptive events; and (c) lateral reclosers avoid sustained outages from nuisance events. The measure also will mitigate the risks to both structural and electrical vulnerabilities on the system.

The Communication Modernization measure will modernize the grid and integrate operational technology and information technology to decrease customer outages and manage other system risks. SPS will make investments in communications systems to enable communication between devices to enable remote device operations. This measure will support future capabilities of the Distribution System Protection Modernization measure; therefore, it indirectly supports mitigation of the same weather events that are mitigated by that measure. The Communication Modernization measure will allow the Automated Recloser Deployment program within the Distribution System Protection Modernization measure to be more effective at minimizing outages for customers and managing other system risks.

The Operational Flexibility measure includes (a) the acquisition of additional mobile substations that will allow SPS to quickly restore service when a substation transformer is damaged or destroyed by a resiliency event and to maintain continuity of service during the substation upgrades proposed in the SRP and (b) the installation of new automated transmission switches that will enhance SPS's ability to sectionalize the transmission system, reducing the frequency and duration of outages and the impact of outages on SPS's wholesale and end-use customers.

Finally, the specific Wildfire Mitigation measure includes both (a) Situational Awareness investments, like AI cameras and wildfire modeling tools to more effectively detect and predict wildfire threats, and (b) Physical Mitigations programs, like increased defensible space around poles and detailed visual inspections that will reduce the likelihood of SPS's infrastructure igniting a catastrophic wildfire. Along with other resiliency investments in the SRP, these programs will help create a safer environment for communities across the SPS service area by reducing the likelihood of fire ignition, protecting SPS's facilities from wildfire damage.

In addition to simply projecting benefits from the investment, the Resiliency Rule requires that each measure include a proposed metric or criteria for evaluating the effectiveness of the measure. SPS proposes metrics that apply to various measures in its SRP, as summarized below.

Table 2 –Metrics for Evaluating Effectiveness					
Metric	**Distribution Overhead Hardening**	**Distribution System Protection Modernization**	**Communication Modernization**	**Operational Flexibility**	**Wildfire Mitigation**
Underperforming Area Count	X	X	X		
Rolling 10-Year Average SAIDI	X	X	X	X	
Storm Restoration Duration	X	X	X		
Average Hardened Protection Zone (AHPZ) CI vs Average Protection Zone (APZ) CI Comparison by County (Hardened Only)	X				
AHPZ CI Percentage Improvement	X				
RAN Tower Completion			X		
End Device Connectivity			X		
Units Completed in DSAP					X
Transmission Inspections					X

These metrics are intended to capture performance improvements from SPS's proposed investments in this Plan, specifically showing how the impacts from severe weather events over time are lessened due to the hardening investments and protection modernization. Additionally, they will capture how SPS's investments in wildfire mitigation are reducing the impacts of fires on our system.

In sum, the SRP is a comprehensive and evidence-based plan developed in collaboration with third-party experts to address the specific needs of our customers, given the unique

characteristics of SPS's Texas service area. The Plan utilizes decades of quantitative, qualitative, and historical data to prioritize risks by events and geography and recommends targeted investments to reduce the impact of severe weather events and wildfire. The analysis from third-party consultants 1898 & Co. and EDM supports the conclusion that these investments are cost-beneficial and in the public interest.

The remainder of this Plan is organized as follows:

- Section II discusses the resiliency events addressed by the SRP;
- Section III discusses SPS's approach to improving system resiliency, including the work performed by 1898 & Co. and EDM;
- Section IV discusses SPS's proposed resiliency measures in this Plan; and
- Section V discusses SPS's proposed metrics for evaluating the effectiveness of its Plan.

II. DESCRIPTION OF RESILIENCY EVENTS AND RISKS ADDRESSED BY THE SRP

The Resiliency Rule requires that a resiliency plan "define, identify, and describe each type of resiliency event and any associated resiliency-related risks the plan is designed to prevent, withstand, mitigate, or more promptly recover from."[5]

SPS's service area is affected by weather-based resiliency events as well as wildfire. SPS and other public utilities are also increasingly facing cybersecurity resiliency events. This Plan includes measures designed to prevent, withstand, mitigate, or more promptly recover from risks posed by each of these events. To understand the weather-based events affecting the resiliency of its system, SPS worked with 1898 & Co. to analyze historic weather data. EDM provided an analysis of historic wildfire data.

A. Weather-Based Resiliency Events Addressed in SRP

1. Weather-Based Resiliency Events in SPS's Service Area

SPS's service area faces numerous types of significant, impactful extreme weather events that can cause forced outages on SPS equipment. These include: (1) Wind, (2) Flooding, (3) Tornado, (4) Winter, (5) Heat, and (6) Cold. SPS engaged 1898 & Co. to comprehensively evaluate the types of extreme weather events that impact the SPS service area. 1898 & Co. began its evaluation by consulting the National Oceanic and Atmospheric Administration ("NOAA") database of non-named weather-based events dating back to 1998 to identify the extreme weather events that have historically impacted the SPS service area and the frequency of those impacts. The NOAA database records events at the county or sub-county level, which allowed 1898 & Co. to collect data on how each type of weather event impacted specific locations in SPS's service area over time. 1898 & Co. identified 21 types of extreme weather events that pose resiliency risks to SPS's service area, divided among seven event categories.

[5] 16 TAC § 25.62(c)(2)(B).

Table 3 below identifies the weather-based resiliency events that pose risks to the SPS service area.

Table 3: Weather-Based Resiliency Events in SPS Service Area

Extreme Weather	
Wind	11. Sleet
1. Thunderstorm Wind	12. Winter Storm
2. Lightning	13. Heavy Snow
3. Hail-Wind	14. Ice Storm
4. High Wind	15. Hail-Winter
5. Strong Wind	16. Blizzard
Flood	**Heat**
6. Flood	17. Heat
7. Heavy Rain	18. Excessive Heat
8. Flash Flood	**Drought**
Tornado	19. Drought
9. Tornado	**Cold**
Winter	20. Cold/Wind Chill
10. Winter Weather	21. Extreme Cold/Wind Chill

Table 4 below defines each of the weather-based resiliency events. These definitions are taken from NOAA's storm data preparation guidelines.

Table 4: Extreme Weather Resiliency Events[6]

No.	Resiliency Event Category	Resiliency Event Type	Definition
1	Wind	Thunderstorm Wind	Winds, arising from convection (occurring within 30 minutes of lightning being observed or detected), with speeds of at least 50 knots (58 mph), or winds of any speed (non-severe thunderstorm winds below 50 knots) producing a fatality, injury, or damage.

[6] *National Weather Service Instruction 10-1605* (July 26, 2021), *available at* https://www.weather.gov/media/directives/010_pdfs/pd01016005curr.pdf.

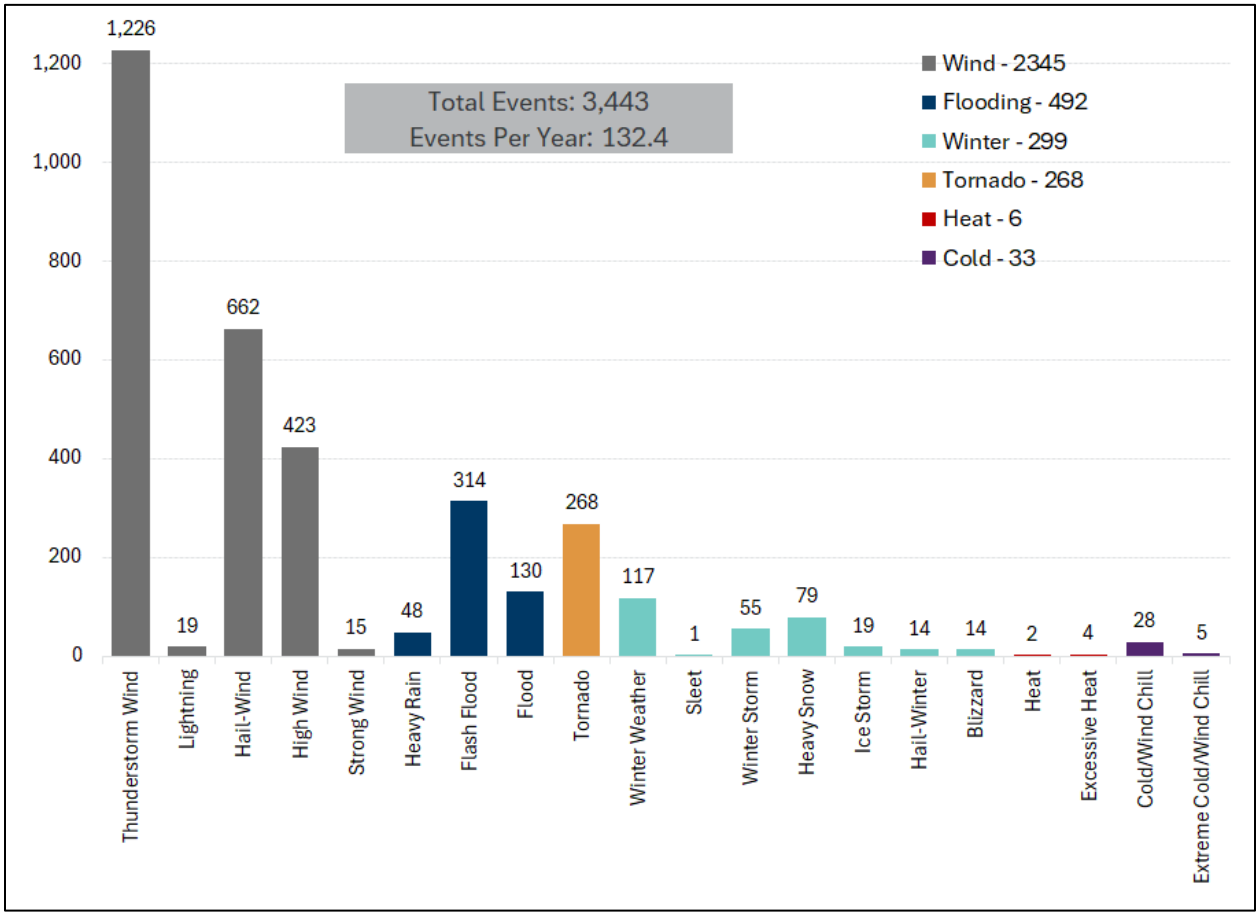
2		Lightning	A sudden electrical discharge from a thunderstorm, resulting in a fatality, injury, and/or damage.
3		Hail-Wind	Hail is defined as, Frozen precipitation in the form of balls or irregular lumps of ice. Hail of any size may be reported, in hundredths of an inch, although the smallest measure in the hail conversion table is 0.25 inches. This report uses "Hail-Wind" to refer to hail that occurs not in connection with a winter-weather event and not during the months of December, January, and February.
4		High Wind	Sustained non-convective winds of 35 knots (40 mph) or greater lasting for 1 hour or longer, or gusts of 50 knots (58 mph) or greater for any duration (or otherwise locally/regionally defined).
5		Strong Wind	Non-convective winds gusting less than 50 knots (58 mph), or sustained winds less than 35 knots (40 mph), resulting in a fatality, injury, or damage.
6	Flood	Flood	Any high flow, overflow, or inundation by water which causes damage.
7		Heavy Rain	Unusually large amount of rain which does not cause a Flash Flood or Flood event, but causes damage, e.g., roof collapse or other human/economic impact.
8		Flash Flood	A life-threatening, rapid rise of water into a normally dry area beginning within minutes to multiple hours of the causative event (e.g., intense rainfall, dam failure, ice jam). Six inches or more of swiftly moving water flowing over a road or bridge, posing a threat to life or property is one of many suggested guidelines for determining if an event was a Flash Flood.
9	Tornado	Tornado	A violently rotating column of air, extending to or from a cumuliform cloud or underneath a cumuliform cloud, to the ground, and often (but not always) visible as a condensation funnel.
10	Winter	Winter Weather	A winter precipitation event that causes a death, injury, or a significant impact to commerce or transportation, but does not meet locally/regionally defined warning criteria. A Winter Weather event could result from one or more winter precipitation types (snow, or blowing/drifting snow, or freezing rain/drizzle).
11		Sleet	Sleet accumulations meeting or exceeding locally/regionally defined warning criteria (typical value is ½ inch or more). Per the National Weather Service, 27 the Southern Region weather criteria for sleet in the State of Texas is ½ inch or more.
12		Winter Storm	A winter weather event that has more than one significant hazard (i.e., heavy snow and blowing snow; snow and ice; snow and sleet; sleet and ice; or snow, sleet and ice) and meets or exceeds locally/regionally defined 12 and/or 24-hour warning criteria for at least one of the precipitation elements.
13		Heavy Snow	Snow accumulation meeting or exceeding locally/regionally defined 12 and/or 24 hour warning criteria. This could mean values such as 4, 6, or 8 inches or more in less than 12 hours or less; or 6, 8, or 10 inches in 24 hours or less. Heavy snow criteria range from 1 inch per event in the southernmost portions of Texas to 4 inches in 12 hours and 6 inches in 24 hours in the northernmost portions.
14		Ice Storm	Ice accretion meeting or exceeding locally/regionally defined warning criteria (typical value is ¼ or ½ inch or more)." The ice accumulation criteria for the southern portion of Texas is 1/8 or more, while the criteria is ¼ inch or more throughout the remainder of the state.

15		Hail-Winter	Hail is defined as, Frozen precipitation in the form of balls or irregular lumps of ice. Hail of any size may be reported, in hundredths of an inch, although the smallest measure in the hail conversion table is 0.25 inches. This report uses "Hail-Winter" to refer to hail that occurs in connection with a winter-weather event, and/or during the months of December, January, and February.
16		Blizzard	A winter storm which produces the following conditions for three (3) consecutive hours or longer: (1) sustained winds or frequent gusts of 30 knots (35 mph) or greater, and (2) falling and/or blowing snow reducing visibility frequently to less than ¼ mile.
17	Heat	Heat	A period of heat resulting from the combination of high temperatures (above normal) and relative humidity. A Heat event occurs and is reported in Storm Data whenever heat index values meet or exceed locally/regionally established advisory thresholds. Heat advisory thresholds range from heat index/temperature levels of 100°F and above to heat index/temperature levels of 110°F and above in Texas.
18		Excessive Heat	Excessive Heat results from a combination of high temperatures (well above normal) and high humidity. An Excessive Heat event occurs and is reported in Storm Data whenever heat index values exceed locally/regionally established excessive heat warning thresholds. Excessive heat warning thresholds range from heat index/temperature levels of 105°F and above to heat index/temperature levels of 115°F and above in Texas.
19	Drought	Drought	Drought is a deficiency of moisture that results in adverse impacts on people, animals, or vegetation over a sizeable area.
20	Cold	Cold/Wind Chill	Period of low temperatures or wind chill temperatures reaching or exceeding locally/regionally defined advisory (typical value is -18°F or colder) conditions.
21		Extreme Cold/Wind Chill	A period of extremely low temperatures or wind chill temperatures reaching or exceeding locally/regionally defined warning criteria (typical value around -35°F or colder).

The NOAA event data shows that 3,443 weather-based resiliency events occurred in SPS's service area from 1998 through 2023, the most recent year for which data is available.[7] Figure 4 below shows the number of occurrences in SPS's service area since 1998, broken down by event type. The most frequent events are Thunderstorm Wind, Hail-Wind, High-Wind, Flash Flood, and Tornado.

[7] 1898 & Co. did not evaluate drought events because their durations are so long that they are difficult to correlate to an outage.

Figure 4: Extreme Weather Events in SPS's Service Area Since 1998



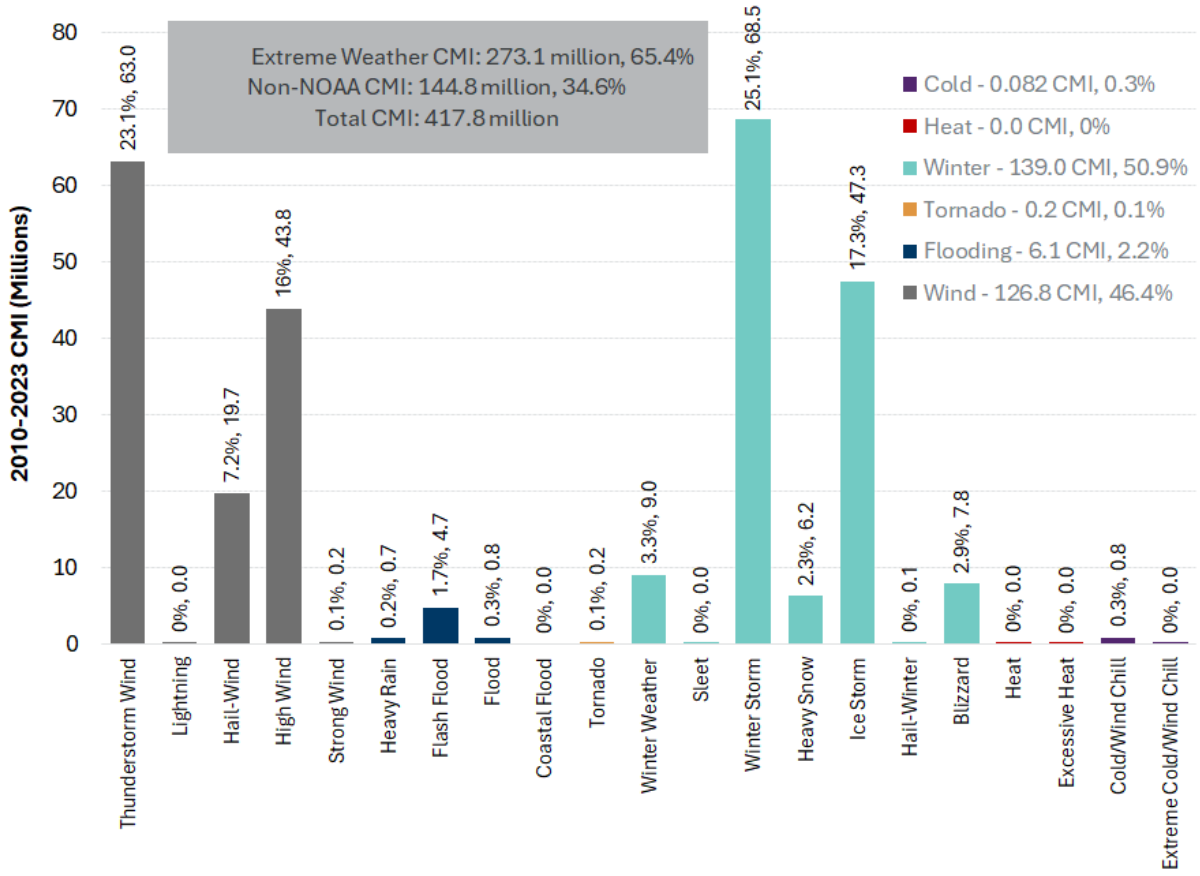
2. Risks Posed by Weather-Based Resiliency Events

The weather-based resiliency events identified by 1898 & Co. pose a number of risks to the SPS system that can result in customer outages. For example, Wind events can cause conductor contact and blow vegetation, debris, or other objects into energized facilities. Wind events can cause structural overloads, potentially toppling poles, snapping conductor, or directly damaging appurtenant equipment. They can also cause galloping conductor when combined with ice or snow. Winter events can cause structural overloads as ice accumulates on facilities and surrounding vegetation. They can also significantly delay restoration efforts, prolonging outages for customers. Heat and Cold events are often accompanied by increased power usage, which can cause thermal overloads on SPS equipment and limit the system capacity available for load transfers, further limiting SPS's ability to restore service. Flood events often have localized impacts that restrict access to structures during an outage event. Approximately 41 percent of the poles on the SPS

system have limited accessibility following heavy rain events. Tornado events, including the surrounding winds that accompany tornados, can also destroy poles, conductor, and other equipment located in their paths.

To quantify the risks that weather-based resiliency events pose to the SPS system, 1898 & Co. correlated the weather-based resiliency events in the NOAA data with outages recorded in SPS's Outage Management System ("OMS"), which data dates to 2010. 1898 & Co. identified over 1,924 NOAA events during which an outage was recorded on SPS's system. 1898 & Co. used data from the OMS to determine the number of Customer Minutes Interrupted ("CMI"), or the total number of minutes that SPS customers collectively were without service during an outage, associated with each resiliency event. 1898 & Co.'s correlation analysis shows that approximately 65.4 percent of all outage minutes recorded since 2010—over 273 million CMI occurred during a weather-based resiliency event. Of those events, Winter Storm, Thunderstorm Wind, Ice Storm, High Wind, and Hail-Wind events had the greatest customer impact, as measured in CMI. In other words, a substantial majority of the customer outages on the SPS system were associated with weather-based resiliency events, and Wind and Winter events were responsible for over 90 percent of those outages. Figure 5 below shows the CMI associated with each type of weather-based resiliency event from 2010 to 2023.

Figure 5: CMI Mapped to NOAA Events (2010-2023)



Finally, 1898 & Co. used the frequency and outage data from NOAA and SPS's OMS data to rank the weather-based resiliency events based on their annual average CMI per event. The ranking shows that Wind and Winter events make up the eight most impactful event types on the SPS System. While Winter events occur less frequently than many other events, they cause a significant number of customer outages when they do occur. Wind events are responsible for a similar amount of CMI compared to Winter events, but they occur much more frequently, so their impacts are spread over a greater number of events. This ranking helped SPS to prioritize the weather-based resiliency events based on their overall customer impact, which guided SPS's selection of the measures and programs to include in the Plan, as described in more detail in Section III. This analysis of weather-based resiliency events allowed SPS to tailor this Plan to prevent, withstand, mitigate, and more promptly recover from the resiliency events with the greatest impact to the SPS service area and its customers.

Table 5: Prioritization of Resiliency Events

No.	Event Category	Event Type	1998 – 2023 Avg Events / Year	Annual Average CMI	Event Frequency Rank	Event Impact Rank
1	Winter	Winter Storm	2.12	68,545,688	9	1
2	Wind	Thunderstorm Wind	47.15	62,993,196	1	2
3	Winter	Ice Storm	0.73	47,320,875	12	3
4	Wind	High Wind	16.27	43,781,368	3	4
5	Wind	Hail-Wind	25.46	19,724,513	2	5
6	Winter	Winter Weather	4.50	8,988,880	7	6
7	Winter	Blizzard	0.54	7,813,848	15	7
8	Winter	Heavy Snow	3.04	6,232,480	8	8
9	Flooding	Flash Flood	12.08	4,664,246	4	9
10	Cold	Cold/Wind Chill	1.08	816,310	11	10
11	Flooding	Flood	5.00	794,983	6	11
12	Flooding	Heavy Rain	1.85	680,936	10	12
13	Tornado	Tornado	10.31	246,922	5	13
14	Wind	Strong Wind	0.58	246,510	14	14
15	Winter	Hail-Winter	0.54	130,885	15	15
16	Wind	Lightning	0.73	35,559	12	16
17	Heat	Heat	0.08	32,855	19	17
18	Winter	Sleet	0.04	13,068	20	18
19	Heat	Excessive Heat	0.15	9,591	18	19
20	Cold	Extreme Cold/Wind Chill	0.19	6,307	17	20
21	Drought	Drought	Not Quantified – Data Not Available to estimate equipment failures and customer outages			

B. Wildfire Risk

Catastrophic wildfires can be devastating to communities and the environment and have become a matter of national priority for utilities, government agencies, legislators, regulators,

customers, investors, ratings agencies, insurers, and other stakeholders. The growing threats from an increased frequency of fire weather conditions, aging infrastructure, and increased development in wildland areas have made preventing wildfires, mitigating ignition risks, and protecting facilities a significant priority for utilities operating in portions of the U.S., including Texas. Wildfire presents a clear and present danger to the safety, reliability, and resiliency of utility systems and the communities served by these facilities. The 2024 Texas Panhandle wildfires are indicative of these conditions and threats.

Understanding the wildfire risk relative to SPS's assets is fundamental to SPS's wildfire prevention and protection efforts. Wildfire risk varies across SPS's geographic service territory. The risk at any given location depends on the fuels, terrain, fire behavior patterns, prevailing weather patterns, proximity of developed areas, and other factors.

Below are general descriptions of Texas wildfire history and characteristics, the increased frequency of wildfire weather conditions and acres burned by wildfires in Texas and the U.S., and recent challenges experienced during wildfire resiliency events in and around SPS's service area.

1. Texas Wildfire Overview

All of the largest wildfires recorded in Texas history have occurred since 1988. Five of the fifteen largest wildfires in Texas history have occurred in, or very near, SPS's service territory.[8] Ninety percent of the 30 largest wildfires in Texas have occurred between January and May, primarily in the grass-dominant Texas Plains. Factors that drive the dormant wildfire season in Texas are grass fuel loading produced during the previous growing season, drought conditions, and seasonal temperature and precipitation. Emerging drought following a wetter-than-normal growing season has produced the most active dormant fire seasons in past years.[9] Each year, the Texas A&M Forest Service and the National Weather Service watch for an extremely dangerous fire weather phenomena known as a Southern Plains Wildfire Outbreak ("SPWO"). The

[8] Historical Fire Statistics, Texas A&M Forest Service, *available at* https://fire-information-tfsgis.hub.arcgis.com/pages/historical-fire-statistics

[9] *2023 Texas Dormant Wildfire Season Expected to be Normal to Below Normal*, Texas A&M Forest Service, (Dec. 1, 2022), *available at* https://ticc.tamu.edu/Documents/PredictiveServices/Outlooks/2023_Dormant_Fire_Season_Outlook_Final.pdf.

environment conducive to a SPWO is characterized by dry vegetation, dry west-southwest winds across an area with low relative humidity, above average surface temperatures, an unstable atmosphere and clear, sunny skies. Historically, SPWO events happen more often during La Niña years. This is because La Niña conditions translate to warmer than normal, and drier than normal, conditions for Texas during the winter and spring months, thereby increasing the potential for high impact wildfire weather and SPWO events. An SPWO event is a force of nature, and much like a hurricane or tornado, it cannot be stopped. Since 2005, SPWO fires account for 3 percent of reported wildfires, but 49 percent of the acres burned.[10]

As winter months and freezing temperatures move in, the growing season ends and grasses cure, turn brown, and become dormant. During this phase, grasses are not actively growing, meaning they are not replenishing and maintaining their moisture levels as they do when they are green. Freeze-cured grasses dry out very quickly and are susceptible to ignition from any spark, which in turn could grow into a wildfire. Grass wildfires can spread very quickly and put residents and communities in the path of danger.[11] Once grass is dry it has a high probability of ignition during periods of low relative humidity and high winds. Depending upon grass height and continuity, a wildfire can grow to over 2,000 acres in size within one hour during periods of high winds. Flame lengths can reach upwards of 34 feet.[12] Wind-driven wildfires characterized by the fire behavior described above challenge even the most robust initial fire suppression attack. High winds also tend to limit the effectiveness of aerial firefighting resources and can cause them to be grounded.

2. Increased Frequency of Wildfire Weather Conditions

To better understand growing wildfire risks across the U.S., a recent national study analyzed historical trends in fire weather, including the analysis of weather data from 476 weather stations across 245 climate divisions during a 50-year period between 1973 and 2022. The study defined fire weather as a combination of three meteorological conditions (i.e., high sustained wind

[10] *Preparing for Wildfires, Southern Plains Wildfire Outbreak,* Texas A&M Forest Service, https://tfsweb.tamu.edu/spwo/.

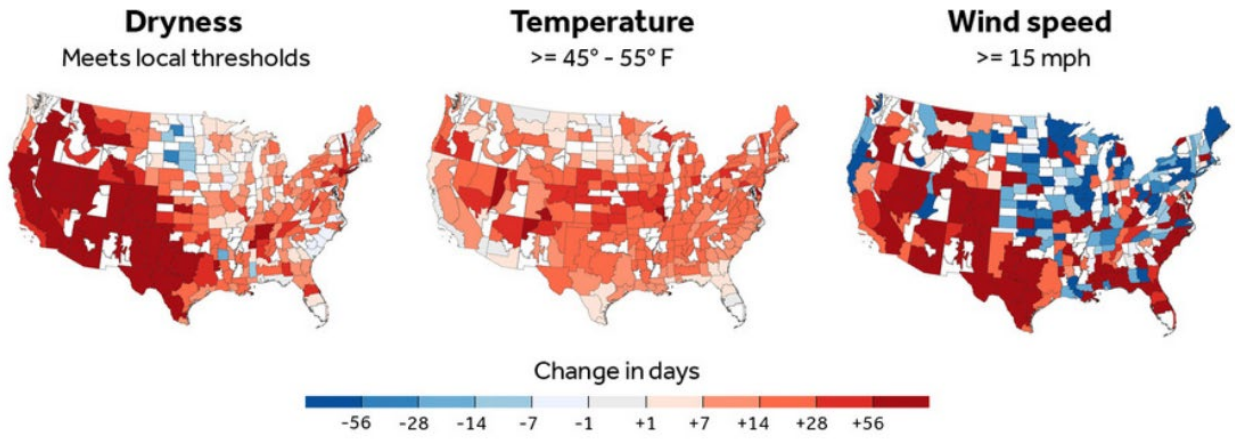
[11] *Id.*

[12] Behave Plus 6.0.0 is a fire behavior prediction and fuel modeling system, https://www.frames.gov/behave/home.

speeds, high ambient air temperatures, and low relative humidity) facilitative for the spread of wildfire. While wind speed, temperature, and humidity are the primary contributors to fire behavior, spread, and suppression difficulty, other environmental factors such as fuel types, fuel densities, and topography can also impact wildfire risk and danger.[13] Figure 6 below depicts the change in average fire weather days from 1973 to 2022, on which the aforementioned three fire weather conditions met or exceeded their corresponding thresholds in each climate division.

Figure 6 – Average Annual Change in the Number of Days on which Each of The Three Critical Fire Weather Meteorological Conditions Thresholds were Met or Exceeded

(1973-2022)

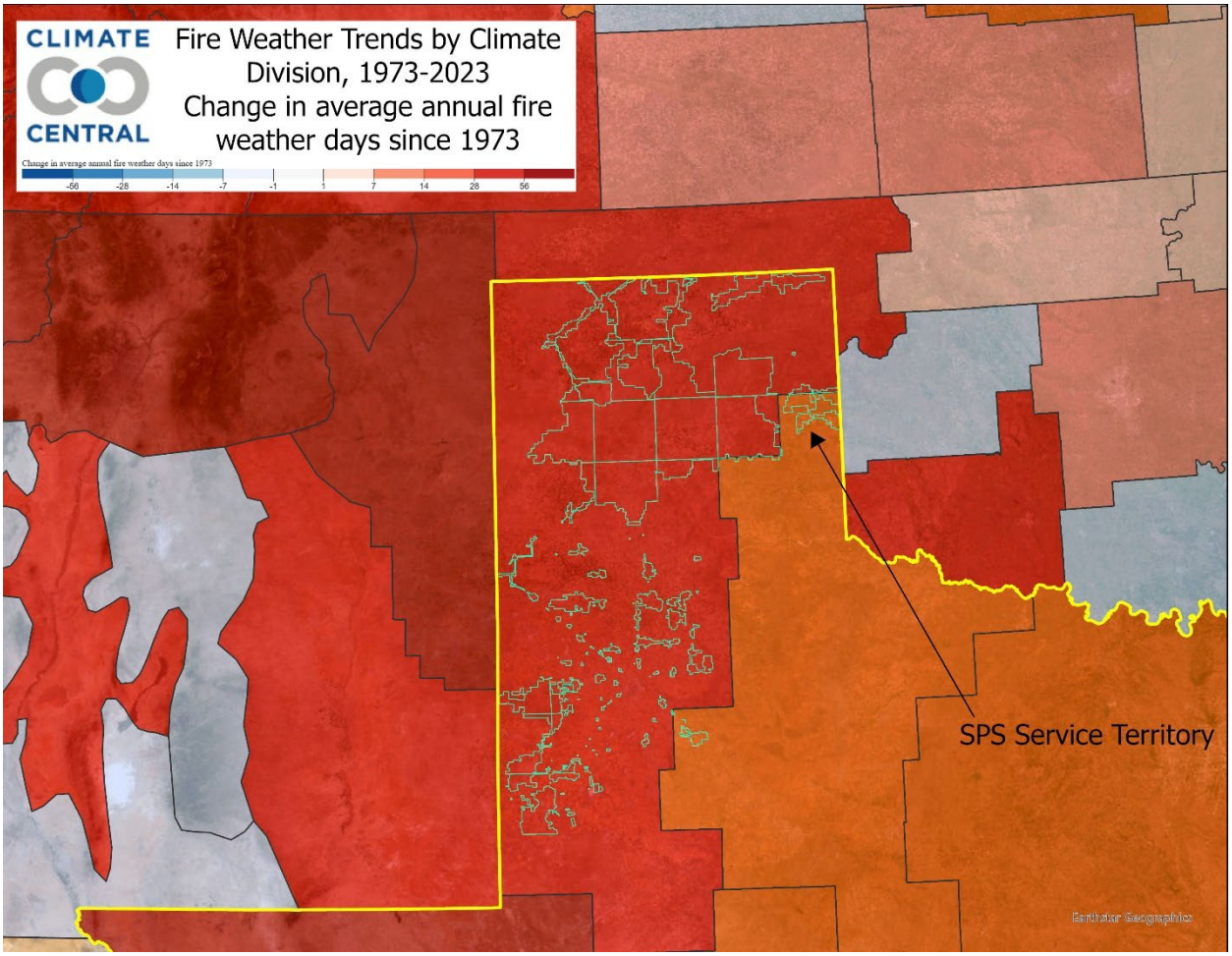


The study concluded that Texas has experienced some of the greatest increases in the average number of annual fire weather days since 1973, with some Texas climate divisions now experiencing approximately two more months of fire weather or more than twice the number of fire weather days now compared to 50 years ago. Figure 7 below depicts the change in average annual fire weather days since 1973 specific to the climate regions in and around SPS's Texas service area.[14]

[13] Wildfire Weather: Analyzing the 50-year shift across America, Climate Central at 3 (May 2023), https://assets.ctfassets.net/cxgxgstp8r5d/1RwlNCKT1zYQFz5NtKW9ue/9a843df6ca96446b1f507a1acabfe0bc/FINAL-Fire_Weather_2023__EN_.pdf.

[14] Wildfire Weather: Analyzing the 50-year shift across America, Climate Central at 6 (May 2023), https://assets.ctfassets.net/cxgxgstp8r5d/1RwlNCKT1zYQFz5NtKW9ue/9a843df6ca96446b1f507a1acabfe0bc/FINAL-Fire_Weather_2023__EN_.pdf.

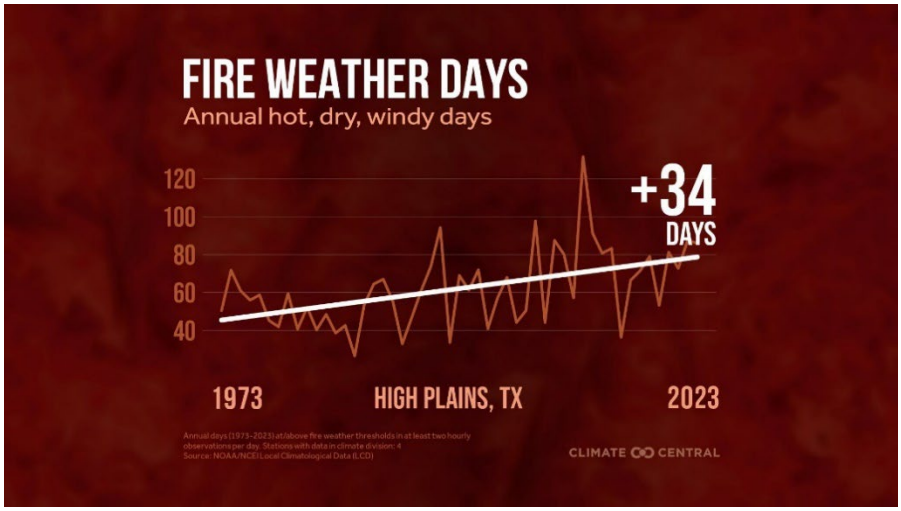
Figure 7 – Change in Annual Number of Fire Weather Days (1973-2022) for Climate Divisions in SPS's Texas Service Area



SPS's service area is completely encompassed by areas experiencing significantly increased wildfire risk over the last 50 years. SPS's service area is located in the High Plains and Low Rolling Plains climate divisions as identified by NOAA's National Centers for Environmental Information. The study identified High Plains, Texas as one of the top 20 national locations with the greatest change in fire weather days during the analysis period with an average increase of 34 annual fire weather days (see Figure 8).[15]

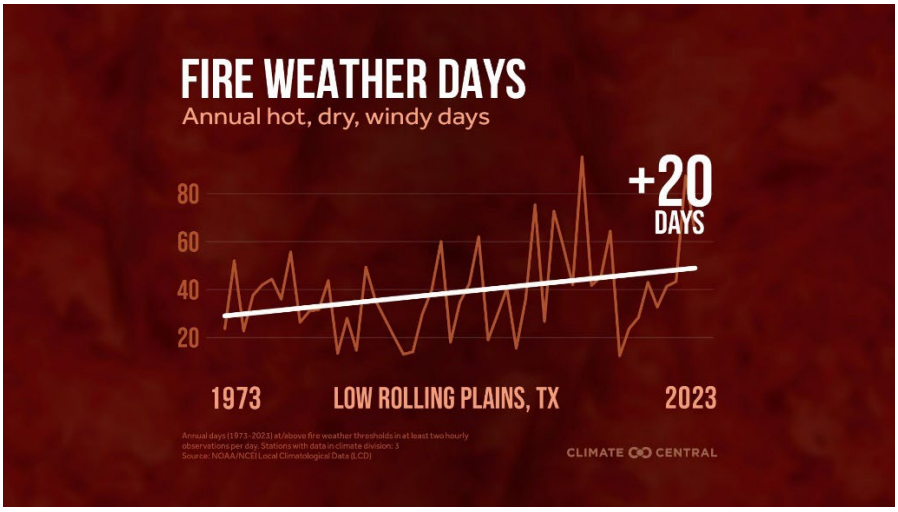
[15] Data used to create the below graphic can be accessed here: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fclimatecentral-web-assets.s3.amazonaws.com%2F2024FireWeather%2F2024FireWeather_DataDownload.xlsx&wdOrigin=BROWSELINK.

Figure 8 – Change in Annual Number of Fire Weather Days in the High Plains, Texas Climate Division (1973-2022)



Low Rolling Plains, Texas was in the top 30 locations experiencing an average annual increase of 20 fire weather days (see Figure 9).[16]

Figure 9 – Change in Annual Number of Fire Weather Days in the Low Rolling Plains, Texas Climate Division (1973-2022)

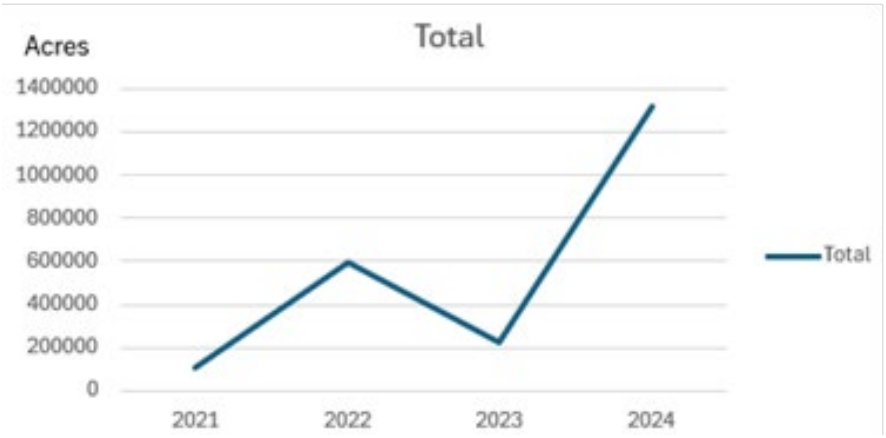


[16] *Id.*

3. Increased Acreages Burned and Frequency of Wildfire Occurrences

A study of recent historical Texas wildfire data indicates a significant increase in the number of acres burned over the previous four years, as depicted in Figure 10.[17]

Figure 10 – Acres Burned in Texas Wildfires (2021 – Year-to-Date 2024)



These data are consistent with other national data that show an upward trend in the number of acres burned by wildland fires across the U.S. Figure 11 below depicts data from the National Interagency Fire Center ("NIFC"). The trendline shows a significant increase in the total number of acres burned in the U.S. in recent decades.[18] Compared to recent years, the U.S. experienced a significant decrease in acres burned in 2023; however, there is a significant increase of acres burned in 2024. For the period between January 1 and December 13, 2024, wildland fires burned 8,509,953 acres. This is approximately two million acres above the 10-year average year-to-date number of acres burned.[19]

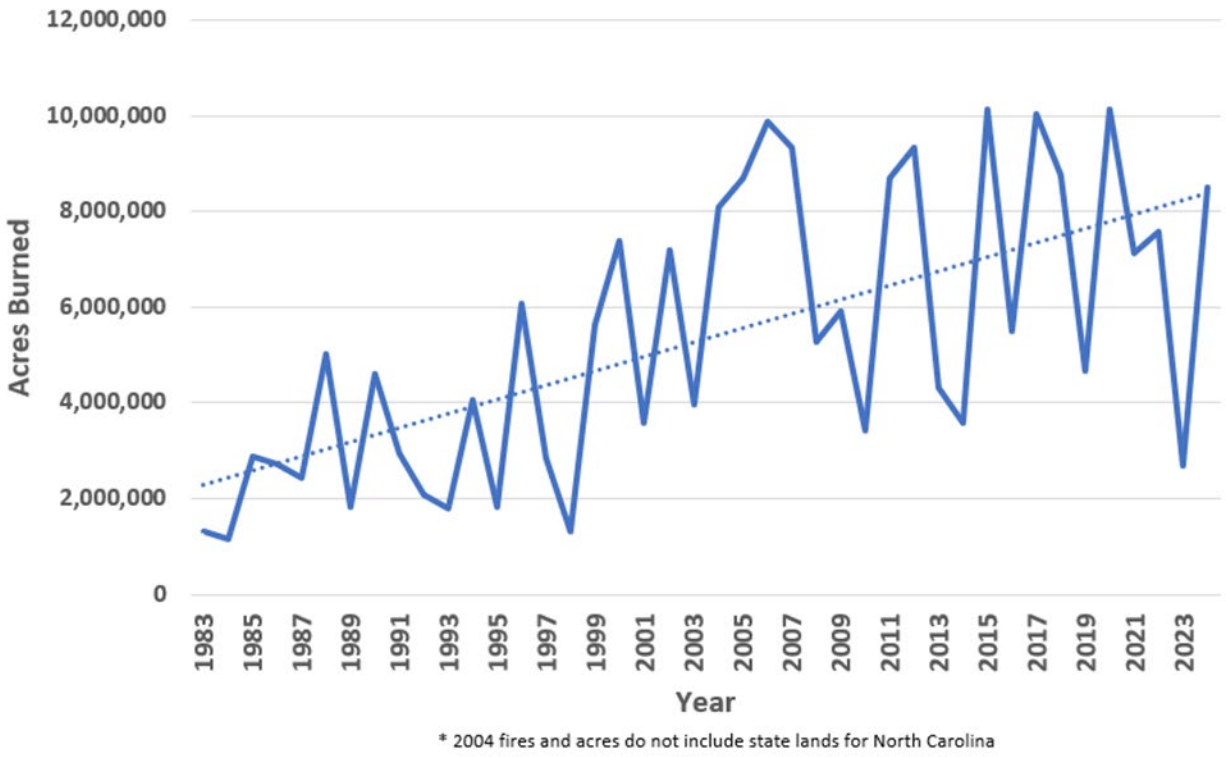
[17] The graph below was created by using the data from the following website: https://services3.arcgis.com/T4QMspbfLg3qTGWY/arcgis/rest/services/WFIGS_Interagency_Perimeters/FeatureServer/0.

[18] *Wildfires and Acres*, National Interagency Fire Center (2023), https://www.nifc.gov/fire-information/statistics/wildfires

[19] *National Fire News*, National Interagency Fire Center (December 2024), *available at* https://www.nifc.gov/fire-information/nfn.

Figure 11 – Annual Number of Acres Burned in U.S. Wildland Fires

(1983 – Year-to-Date 2024)



As extreme weather conditions become more frequent, SPS can expect more frequent and disruptive wildfire events.[20] In their Potential Impacts of Climate Change on U.S. Wildfire Risk by Mid Century of Sept 2021, the Society of Actuaries Research Institute predicts that the Texas Panhandle will experience a 120 percent to 250 percent increase in mean annual acres burned, and a 90 percent to 120 percent increase in the mean number of wildfires.[21] Improved situational awareness, grid hardening, and other pre-planning will help reduce the negative impacts to SPS customers and stakeholders from these kinds of resiliency events.

[20] Alexandra Hart, *More Frequent – and Worsening – Extreme Weather Events are Ahead for Texas*, Texas Standard, (April 25, 2024), *available at* https://www.texasstandard.org/stories/more-frequent-and-worsening-extreme-weather-events-are-ahead-for-texas/.

[21] *Potential Impacts of Climate Change on U.S. Wildfire Risk by Mid Century*, SOA Research Institute, (September 2021), https://www.soa.org/4a8096/globalassets/assets/files/resources/research-report/2021/climate-change-impacts-to-us-wildfire-risk.pdf.

4. Recent Wildfire Resiliency Events and Subsequent Wildfire Risk

The Smokehouse Creek Fire, the single largest wildfire in Texas history, and the Grape Vine Creek, Windy Deuce, and Reamer Creek fires are all indicative of recent utility-related wildfire resiliency events.[22] Collectively, these wildfires burned over one million acres across the Texas Panhandle and Oklahoma in February 2024. Challenges that hindered response times and firefighting efforts were identified in the aftermath of the fires, including a lack of readily available fire-suppression air support, partially ineffectual agency and first-responder communication and coordination, and faulty equipment and infrastructure.[23] The Texas Panhandle fires reinforce the need for SPS's enhanced wildfire prevention and protection programs to increase the safety and resiliency of the electric system for the communities SPS serves. SPS's Wildfire Mitigation measure and its supporting programs are designed to help address and mitigate some of these aforementioned challenges.

It is important to note that landscape wildfire risk persists in the aftermath of the Texas Panhandle fires. The predominant fuels in the region are finer fuels such as grasses and small woody shrubs. Native grasses usually survive wildfires. When a fire sweeps through, it takes the dead plant material from the surface, but grass grows back quickly because most of the plant is below ground and escapes long-term damage. The key to grass growth is the amount of rainfall, not whether there has been a wildfire. Moreover, a fire can improve the quality of the forage by clearing out old vegetation and allowing for increased growth of grass types with more protein.[24]

C. Cybersecurity Risks

Cybersecurity is a top priority for SPS. One of SPS's long-term strategic objectives is to modernize its electric facilities and equipment by deploying upgraded information technology ("IT"), operational technology ("OT"), and communications devices and applications. Upgrading aging, analog devices on the SPS system with modern digital and communications-enabled

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[22] *Investigative Committee on the Panhandle Wildfires*, Texas House of Representatives at 15 (May 1, 2024), *available at* https://www.house.texas.gov/pdfs/committees/reports/interim/88interim/House-Interim-Committee-on-The-Panhandle-Wildfires-Report.pdf

[23] *Id.*

[24] *Rangeland Grasses Recover Quickly After Fire*, United Stats Department of Agriculture, *available at* https://agresearchmag.ars.usda.gov/2017/sep/grasses/.

replacements can provide value to SPS's customers, make the SPS system more reliable, and increase customer engagement. For example, in 2022, the Commission approved SPS's deployment of an Advanced Metering System, which allows SPS to collect more granular data and exercise more precise control over retail delivery systems and operations.[25] Similarly, in this Plan, SPS proposes to deploy hundreds of communications-enabled protective devices that require reliable, secure network communications to automate switching operations, transfer customer load, enable remote control of device settings, and allow SPS to remotely monitor system conditions. While these enhancements present promising opportunities, they are accompanied by new vulnerabilities that must be carefully managed.

The electric grid is critical infrastructure that is vital to the U.S. economy.[26] As such, it presents an attractive target for bad actors seeking to exploit vulnerabilities for political or financial purposes.[27] The proliferation of connected devices on the electric grid increases SPS's reliance on communications infrastructure outside its control, which in turn increases the potential attack surface for cyber-attacks.[28] In January 2024, the U.S. Department of Energy expressly acknowledged the importance of this threat, defining cyber-resilience for critical energy infrastructure as one of the five pillars of its Cybersecurity Strategy.[29]

Recent events validate concerns regarding the risk of cyber-attacks on electric utility infrastructure. In September, Reuters reported that cyber-attacks targeting U.S. utilities surged 70

[25] *Application of Southwestern Public Service Company for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees*, Docket No. 52451, Order (Jul. 14, 2022).

[26] U.S. Department of Energy-Office of Electricity, *Communications in the Electric Grid* at 3 (Nov. 2023), *available at* https://www.energy.gov/sites/default/files/2023-11/Communications_in_the_Electric_Grid_An_Evolving_%20Interdependent_Ecosystem_between_the_Grid_and_Communications_Utilities-r1.pdf

[27] *Id.*

[28] *Id.*

[29] *U.S. Department of Energy Cybersecurity Strategy* at 7-8 (Jan. 2024), *available at* https://www.energy.gov/cio/articles/doe-cybersecurity-strategy-2024.

percent in 2024.[30] This includes multiple attacks that caused operational issues for Texas public utilities serving over 2 million people. One such attack targeted utility systems in Hale Center and Muleshoe, both of which are located in SPS's service area.[31] SPS's extensive, and often remote, critical infrastructure can make SPS systems a particularly attractive target for cyber-attacks.

Documented cybersecurity breaches like the Colonial Pipeline event in 2021 illustrate how damaging cyber-attacks can be for critical infrastructure systems and markets. In 2021, Colonial Pipeline was forced to shut down one of the largest pipeline systems in the U.S., over 5,500 miles of pipeline, after hackers gained access to the Colonial Pipeline IT network, stole 100 gigabytes of data, and infected the network with ransomware that affected multiple computer systems. Colonial Pipeline was only able to regain control of the network after paying the hackers a multi-million-dollar ransom. By that time, the attack had resulted in widespread fuel shortages and a spike in gas prices.

In a 2021 congressional report, the National Academy of Sciences observed that stopping directed attacks targeting critical energy infrastructure will require "sophisticated, multifaceted defenses."[32] But grid operators often have limited control over cyber-security defenses for communications over public networks. For example, while SPS has a robust cybersecurity framework for OT/IT communications, it is completely reliant on public carriers to secure communications transmitted through a public cellular network. SPS's data is not prioritized on these networks, and SPS has no ability to monitor the communications once they are transmitted to the public network. This creates a potential vulnerability in SPS's cybersecurity defenses that could be exploited by bad actors.

In November 2024, the Federal Bureau of Investigation ("FBI") and Cybersecurity & Infrastructure Security Agency ("CISA") warned that state-sponsored hackers had for months

[30] *See Cyberattacks on US Utilities Surged 70% This Year, Says Check Point*, Reuters (Sep. 11, 2024), *available at* https://www.reuters.com/technology/cybersecurity/cyberattacks-us-utilities-surged-70-this-year-says-check-point-2024-09-11/.

[31] *Rural Texas Towns Report Cyberattacks that Caused One Water System to Overflow*, Texas Tribune (Apr. 19, 2024), *available at* https://www.texastribune.org/2024/04/19/texas-cyberattacks-russia/.

[32] National Academy of Sciences, *The Future of Electric Power in the United States* at 225 (2021), *available at* http://nap.nationalacademies.org/25968

infiltrated public cellular networks and other telecommunications infrastructure, placing user data at risk of interception or alteration.[33] CISA issued another statement on December 18, 2024, warning that all "highly targeted individuals should assume that all communications between mobile devices" are at risk. As explained above, public utility infrastructure is increasingly being targeted by cyber-attacks in an effort to disrupt the operation of critical infrastructure. An attack targeting SPS's OT/IT communications could potentially disrupt service for thousands of SPS customers. Accordingly, this Plan includes investments to mitigate the risks that cybersecurity threats pose to SPS, its systems, and its customers.

[33] *See Joint Statement from FBI and CISA on the People's Republic of China (PRC) Targeting of Commercial Telecommunications Infrastructure* (Nov. 4, 2024), *available at* https://www.cisa.gov/news-events/news/joint-statement-fbi-and-cisa-peoples-republic-china-prc-targeting-commercial-telecommunications.

III. SPS'S APPROACH TO IMPROVING SYSTEM RESILIENCY

A. Measure Selection

1898 & Co. assisted SPS in the selection, design, and scoping of the proposed measures. As described in more detail in the 1898 & Co. report, included as Attachment A, 1898 & Co. used the Integrated Resilience and Risk Investment Model to evaluate the effectiveness and quantify the expected benefits for potential resiliency investments included in their evaluation. For each investment activity, 1898 & Co. calculated expected customer benefits by monetizing the value of (1) the reduction in the frequency and duration of outages (measured as CMI) and (2) avoided restoration costs. 1898 & Co. compared these benefits with the estimated costs of each investment to calculate the BCR. The BCR value represents 1898 & Co.'s sophisticated modeling of resiliency events, infrastructure vulnerabilities, rebuild costs, quantified customer benefits, and other factors to provide a reliable measure of the net benefit of resiliency investments for customers.

Ultimately, SPS selected the measures, programs, and activities presented in this SRP based on several objectives, including (1) mitigating the impacts of resiliency events with the greatest impacts on the SPS system and its customers, as determined by SPS's operational experience and the 1898 & Co. analysis; (2) furthering SPS's long-term resiliency objectives, including mitigating wildfire risks and modernizing system protection capabilities; (3) leveraging the BCR, which accounts for the historical performance of the system during resiliency events; and (4) optimizing the overall size of the Plan, with consideration for the costs to customers and SPS's ability to execute on the full portfolio of proposed investments between 2025 and 2028.

The proposed measures consist of new programs that will work in conjunction with existing programs and activities to make the SPS system more resilient and expansions of ongoing resiliency-related investments.

B. Project Prioritization and Implementation

SPS will prioritize execution of individual projects within each measure based on (1) the wildfire risk in an area, prioritizing work in areas designated as Wildfire Risk Tier 3 and Tier 2 by the Wildfire Risk Map developed in collaboration with EDM and (2) the BCR value for all projects with quantified benefits. This approach ensures that SPS is prioritizing work based on the

landscape/population wildfire risk and the historical performance of feeders, while providing further support to advance existing initiatives beyond what would be feasible outside of the SRP. SPS intends to implement this prioritization strategy at the circuit level by grouping investments so that all protection zones on a circuit that are targeted for investment under any of the five measures are addressed together. Based on this approach, several programs across various measures will be completed at the same time. This will promote the efficient use of work crews to save time and labor costs in the implementation of the Plan, which will aid SPS in its ability to fully execute on the SRP investments.

SPS is prioritizing wildfire mitigation efforts to address assets and vegetative fuels located in areas that have an elevated risk for wildfire danger and increased risks to human life and property. Areas prioritized for wildfire risk mitigation are based on risk levels established by the Wildfire Operations Map and the iterative approach to assess the landscape/population wildfire risk in SPS's service area discussed in Section IV.G.2 of this SRP. SPS has used its Wildfire Operations Map to prioritize its Wildfire Mitigation measure programs and supporting activities in the heightened wildfire risk areas located in its Texas service area (i.e., Wildfire Tiers 2 and 3). SPS will continue to use the Wildfire Operations Map to guide the implementation of the approved programs and activities.

C. Ongoing Resiliency Approach

SPS's commitment to resiliency did not begin with this SRP. As detailed in the Annual Summary Report on Infrastructure Storm Hardening,[34] SPS's storm hardening philosophy is to install overhead lines that meet or exceed the needs of its service area. This section describes several of SPS's ongoing programs, initiatives, and standards that contribute to system resiliency. Several of these initiatives are based on inspection and as-needed replacement of existing facilities and equipment to proactively identify defects or vulnerabilities and prevent failures before they occur. These ongoing programs will work in conjunction with the measures proposed in the SRP to further enhance the resiliency of the SPS system.

[34] *See* Reports of Storm Hardening, Project No. 39339, SPS Storm Hardening Report at 2 (May 1, 2024).

1. Construction Standards

In 2014, SPS updated its construction standards, transitioning from Grade C to Grade B construction for all new and rebuilt overhead facilities. Grade B is the highest grade of construction under the National Electric Safety Code ("NESC") and results in the highest strength and largest safety factors for overhead distribution facilities. Historically, this standard was used for transmission lines and was not typical for distribution lines. Extending the Grade B standard to all new and rebuilt distribution facilities means that all overhead lines installed since 2014 are hardened to SPS's highest standard, making them better able to withstand and mitigate resiliency events that impact the SPS service area.

2. Wood Pole Inspection and Treatment

As a part of the Wood Pole Inspection and Treatment Program, SPS has invested approximately $109 million to replace over 21,000 wooden poles since 2020. Regularly inspecting the health of poles is a crucial element of asset health management, because wooden poles decay with time and exposure to elements and wildlife. To manage pole health, SPS conducts frequent assessments and maintains a continuing pole replacement schedule. The Wood Pole Inspection and Treatment Program provides for a ground line inspection and remedial protective treatment for wood distribution and transmission poles. Wood poles are on a rotating cycle for inspection, with all wood poles receiving a visual inspection every 12 years and poles older than 10 years old receiving an invasive ground line inspection, assessment, and remedial treatment to arrest any existing deterioration and prevent future damage. Poles receiving an invasive inspection are assessed for remaining strength. Poles found to be compliant with the NESC guidelines receive remedial treatments and remain in service. Poles found to not be compliant with the NESC guidelines are prioritized for either replacement with Grade B construction or for ground line reinforcement to bring the pole into compliance. Because pole failures contributed to the largest amount of CMI from 2020-2022,[35] pole inspections have played, and will continue to play, an

[35] *See CY 2022 Electric Utility Service Quality Report Under 16 TAC § 25.81*, Project No. 54467, Southwestern Public Service Company's Report in Response to the Commission's December 14, 2023 Order in Docket No. 55614 at 3-4 (December 15, 2023).

important role in identifying and mitigating pole failures. Poles that have been upgraded since 2014 will not be addressed as a part of this SRP.

3. Routine Overhead System Maintenance

Through this program, SPS performs circuit assessments and any necessary rebuilds to resolve identified defects. This program reviews the entire SPS distribution system on a three-to-five-year cadence. Aspects of the underground system are reviewed as a part of the program; however, the primary focus is the assessment of overhead pole equipment including crossarms, cutouts, arrestors, conductor, jumpers, insulators, and other supporting equipment and hardware. SPS began this program in 2017 and has completed two full rounds of patrols, while currently nearing completion on the third round. Since 2017, SPS has addressed defects at over 49,000 locations.

4. Feeder Performance Improvement Program ("FPIP")

The FPIP program identifies the worst performing feeders in SPS's service territory and creates capital projects to improve their reliability. SPS compiles an annual list of distribution feeders, ranks them based on multiple reliability metrics, and completes a detailed engineering analysis to identify beneficial upgrades. Consistent with the Resiliency Rule, all activities proposed in this SRP are incremental to this program.

5. Advanced Capital Projects Initiative

SPS's Advanced Capital Projects initiative identifies facilities and areas of the system that need additional hardening based on specific input from SPS personnel regarding issues such as line condition, operating concerns, flexibility, and customer impact.

6. Fault Location Isolation and Service Restoration Project ("FLISR")

Under the FLISR project, SPS uses data from its Advanced Distribution Management System ("ADMS") to identify distribution feeders for modernization and equips selected facilities with automated field devices such as reclosers. SPS selects facilities based on the number of outages impacting the feeder mainline over the prior year, prioritizing the feeders with the greatest number of mainline outages. The devices installed under FLISR are integrated with the ADMS, allowing SPS to remotely monitor system conditions and control device settings.

IV. PROPOSED RESILIENCY MEASURES

This SRP is an integrated portfolio of measures and investments designed to collectively mitigate the risks posed to SPS's System by the resiliency events described above. SPS organized the SRP into five measures:

(1) Distribution Overhead Hardening

(2) Distribution System Protection Modernization

(3) Communication Modernization

(4) Operational Flexibility

(5) Wildfire Mitigation

SPS developed these five measures to address risks associated with resiliency events that pose a risk to the safe and reliable operation of the SPS System. As described above, these categories of resiliency events include Wind, Flood, Tornado, Winter, Heat, Cold, and Wildfire. Each SRP measure described in this section includes programs, activities, standards, services, procedures, practices, structures, or equipment used to address the risks these resiliency events pose to the SPS System. Implementing these measures will advance SPS's efforts to harden and modernize the grid, and integrate operational and information technology, which will better equip the SPS System to prevent, withstand, mitigate, and more promptly recover from the identified resiliency events and associated risks. Customers will benefit from a reduction in the frequency and duration of outages, reduced system restoration costs, and improvements in overall service reliability. Customers will also benefit from reductions in wildfire risk, general safety benefits, and improved service in areas of lower performance. The Commission's approval of this SRP will significantly enhance SPS's efforts to build a more resilient electric system.

A. Distribution Overhead Hardening

The Distribution Overhead Hardening Measure includes a comprehensive look at each protection zone along the feeder, identifies deficiencies in the construction, and rebuilds all facilities needed to upgrade the zone to SPS's current standards. This measure includes replacing distribution poles, conductor, line transformers, and open wire secondary; trussing/reinforcing distribution poles; adding new poles to mitigate long span-lengths; wrapping poles to mitigate

external wildfire risks in areas of heightened wildfire risk; and replacing arrestors and transformer fuses with non-expulsion alternatives to prevent ignitions in areas of heightened wildfire risk as a part of the Distribution Overhead Hardening measure.

Overhead distribution lines are a central focus of this SRP, as SPS's distribution system consists of 93 percent overhead lines and 7 percent underground lines.[36] SPS's service territory covers a vast, primarily rural, area with distribution lines often traveling great distances between customers. Many of these lines were built with long spans between supporting structures to reduce the number of poles needed to cover the distance. Long span lengths combined with large open areas with high wind conditions and icing potential make conductor more susceptible to galloping and contact, which can lead to overall fatigue and increased loading on the supporting structures.

1. Resiliency Events Mitigated

The Resiliency Rule requires that, for each measure, the utility must identify "one or more risks posed by resiliency events that the measure is intended to prevent, withstand, mitigate, or more promptly recover from."[37] In this section, SPS describes the resiliency events and risks this measure is designed to address.

The Distribution Overhead Hardening measure will enhance the structural integrity of SPS's overhead infrastructure to prevent, withstand, and mitigate the weather-based resiliency events and wildfire risks described in Section II above. This measure will mitigate risks posed by (1) Wind, (2) Flood, (3) Tornado, (4) Winter, (5) Heat, (6) Cold, and (7) Wildfire.

Pole replacements, additions, and reinforcement under this measure will reduce span lengths and make the rebuilt facilities more capable of surviving a Wind, Flood, Tornado (unless in the direct path of a tornado), and Winter events that can cause structural overloading. Conductor upgrades will increase structural integrity and provide additional capacity to prevent thermal overloads and facilitate load transfers during Heat and Cold events. The additional structural integrity from these activities will reduce the likelihood of conductor contact or broken equipment

[36] *See CY 2022 Electric Utility Service Quality Report Under 16 TAC § 25.81*, Project No. 54467, Southwestern Public Service Company's Report in Response to the Commission's December 14, 2023 Order in Docket No. 55614 at 4 (December 15, 2023).

[37] 16 TAC § 25.62(c)(2)(A).

igniting a wildfire. Replacing fuses and arrestors with non-expulsion alternatives in areas of heightened wildfire risk will also reduce ignition risk, and pole wraps in areas of heightened wildfire risk will protect facilities from external wildfire damage.

2. Description of Program in the Distribution Overhead Hardening Measure

The Resiliency Rule requires that the resiliency plan "must be organized by measure" and include "a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure."[38] This section provides a description of the Overhead Hardening measure in compliance with this requirement.

The Distribution Circuit Hardening Rebuilds program within the Distribution Overhead Hardening measure is designed to increase the resiliency of the SPS System through comprehensive rebuilds to increase the structural integrity and carrying capacity of overhead facilities.

Facilities hardened under this measure will be rebuilt to Grade B construction standards. This will allow the hardened facilities to withstand or mitigate many resiliency events that pose a risk to the SPS System. Where full rebuilds are the recommended solution, SPS will shorten span lengths beyond what is required by Grade B standards to prevent conductor contact during high-wind events.

In designing the Distribution Overhead Hardening Measure, SPS and 1898 & Co. considered (1) the wide range of resiliency event types, frequencies, and impacts, which pose varied risks to the system; (2) the makeup of the system, including customer counts and types, infrastructure age and condition, and significant deviations from current design standards; and (3) the cost of investments to address vulnerabilities and improve the resiliency of infrastructure, including partial and full rebuilds to the current hardening standards.

As shown in the 1898 & Co. report, approximately $1.8 billion of potential Distribution Overhead Hardening work has a BCR greater than 1.0. The BCR for all projects included in the

[38] 16 TAC § 25.62(c)(2).

SRP is at least 3.22, meaning the benefits of every project completed under this measure will exceed its costs more than three times over.

2.1 Description of Distribution Circuit Hardening Rebuilds Program

The Distribution Overhead Hardening measure is comprised of a single program: Distribution Circuit Hardening Rebuilds program. The program is comprised of seven discrete activities.

Details of the activities described below outline the guidelines given to 1898 & Co. to generate project estimates. Specific project scopes will be refined following a field review and engineering analysis prior to design and construction.

2.2 Descriptions of Activities within the Distribution Overhead Hardening Measure:

2.2.a Pole Replacements and Installations, Long Span Length Reduction

SPS will install new poles to address long span lengths and replace existing poles based on their age. New span lengths will be determined according to the conductor size to reduce loading on the supporting poles and prevent conductor contact during high-wind events. Table 6 below outlines the standards for span length under this measure. SPS will replace poles installed prior to 1980, which are now nearing their average approved service lives of 53 years.

Table 6 – Span Lengths

Wire Size	Additional Pole Needed for Spans Greater Than
#2	240ft
2/0	280ft
4/0	300ft
336 ACSR	290ft

2.2.b Pole Trussing

In locations where SPS finds that the addition of a new pole is not necessary to mitigate long span lengths or replacement is not identified based on age, poles that meet the below criteria will be trussed to reinforce the strength of the pole. Trussing adds new physical supports to the pole, which is particularly beneficial to harden areas of the overhead distribution system where span lengths exceed SPS's current standard but are not long enough to justify the addition of a new pole.

Figure 12: Image of Trussing



Table 7 – Truss Range	
Wire Size	**Truss Poles for Span Lengths Between**
#2	-
2/0	245ft - 280ft
4/0	230ft - 300ft
336 ACSR	215ft - 290ft

2.2.c Conductor Replacements

SPS will replace vulnerable conductor and secondary wire to meet current construction standards. This activity will target small-wire primary conductor, open-wire secondary, and other conductor installed prior to when the current design standards took effect. Small-wire primary includes conductor that is 4 American Wire Gauge ("AWG") or smaller, which is an outdated standard and provides limited carrying capacity. Due to its age, small-wire conductor often is brittle and typically has been spliced multiple times. Small-wire primary will be replaced with primary conductor of a larger size and carrying capacity. Where primary conductor is selected for replacement, SPS anticipates that a full rebuild of the protection zone will be required, including all poles installed prior to 2014.

Open wire secondary is composed of uninsulated conductor, installed pole to pole, that are located below the primary conductor(s) on the overhead distribution system. It is highly susceptible to damage from weather events due to exposure to vegetation. Outages associated with open wire secondary often require substantial time to repair and place back in service. Open wire secondary will be replaced with lashed cable where the primary conductor has been selected for replacement.

Figure 13: Image of Open Wire

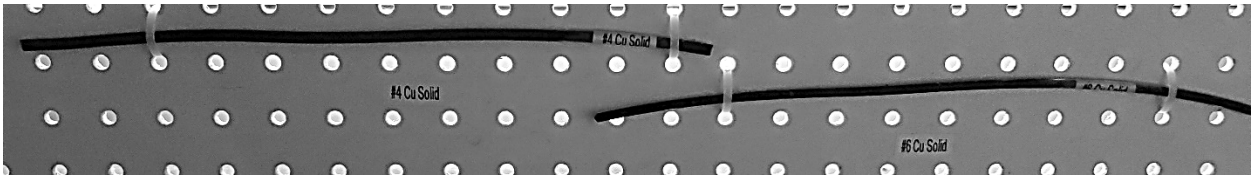
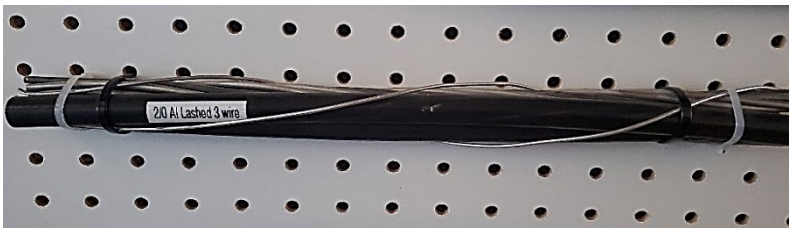


Figure 14: Image of Lashed Cable



2.2.d Line Transformer Replacements

SPS will replace line transformers that are approaching their end-of-life in protection zones hardened under the Distribution Overhead Hardening measure.

2.2.e Wildfire Pole Wraps

This activity involves wrapping poles in fire retardant material to mitigate the risk of pole damage from wildfires. SPS will install pole wraps on all poles that are located in areas of heightened wildfire risk.

2.2.f Expulsion Fuse Replacement

SPS will replace expulsion fuses and associated fuse cutouts with non-expulsion equivalents to mitigate the risk of wildfire ignition. Non-expulsion fuses reduce wildfire ignition risk because they do not emit sparks when they operate. SPS will replace fuses and fuse cutouts in protection zones selected for rebuilds under this measure that are located in areas of heightened wildfire risk.

Figure 15: Expulsion Fuse Sparking

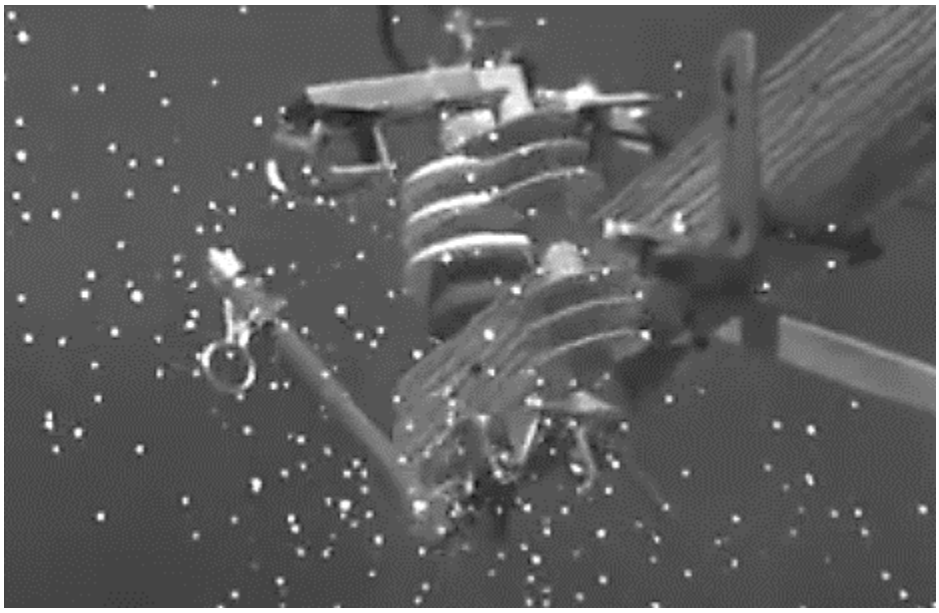
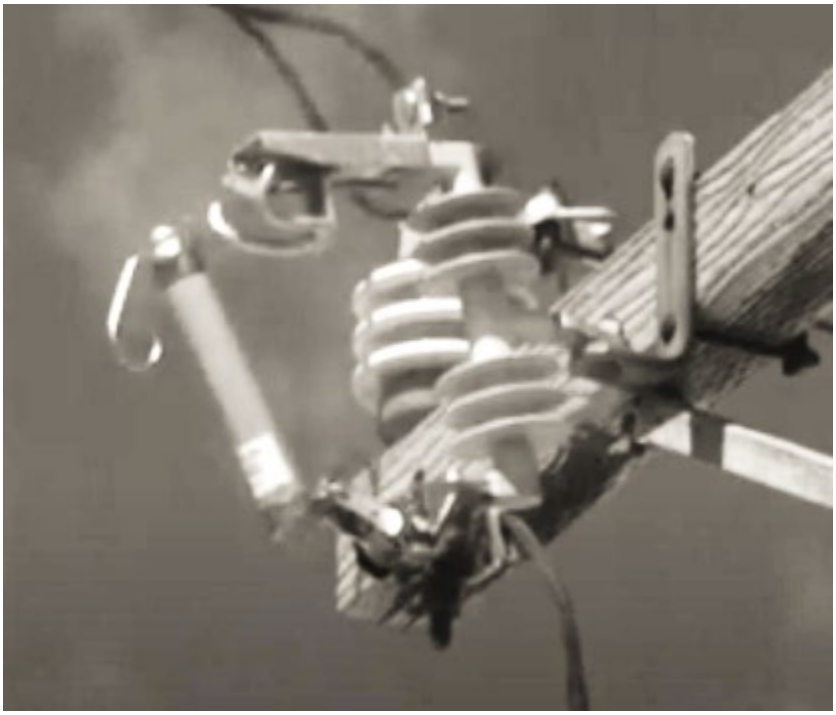


Figure 16: Non-expulsion Fuse in Operation



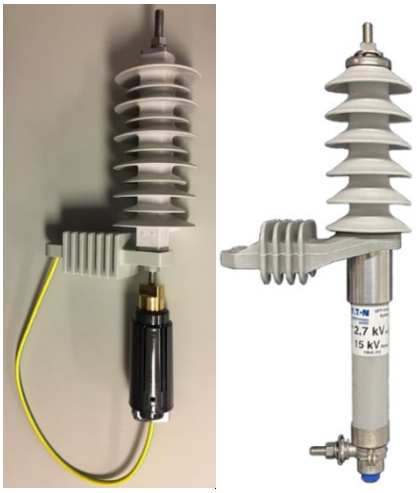
2.2.g Wildfire Arrestor Replacement

SPS will replace wildfire arrestors on in-line transformers with non-expulsion equivalents to mitigate the risk of wildfire ignition. Non-expulsion arrestors reduce wildfire ignition risk because they do not emit sparks when they operate. SPS will replace arrestors in protection zones selected for rebuilds under this measure that are located in areas of heightened wildfire risk.

Figure 17: Standard Arrestor



Figure 18: Wildfire Arrestors



3. Evidence of Effectiveness and Expected Benefits

The Resiliency Rule requires an SRP to "include evidence of the effectiveness of the measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the identified resiliency event."[39] Evidence that is quantitative, performance-based, or provided by an independent entity with relevant experience is afforded greater weight.[40] Further, the SRP must "explain the expected benefits of the resiliency measures including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers, and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations."[41]

SPS engaged 1898 & Co. to evaluate the effectiveness and expected benefits for the Distribution Overhead Hardening measure. 1898 & Co. comprehensively evaluated the SPS overhead system to identify potential hardening projects. Each project consists of the full set of equipment additions, upgrades, and replacements necessary to bring a protection zone into full compliance with SPS's current hardening standard. The results of this evaluation are provided in Section 6.1.4 of the 1898 & Co. report. Table 8 below summarizes the results of the benefit-cost analysis for the projects included in the Plan.

Table 8 Distribution Overhead Hardening Projects

Average BCR	Minimum BCR	Average CMI Reduction	Avoided Restoration Costs
4.7	3.22	58%	76%

The Distribution Overhead Hardening projects included in the Plan have an average BCR of 4.7, with a minimum of 3.22. This means that the expected customer benefits for every project that SPS proposes are at least three times greater than the estimated costs. 1898 & Co. estimates

[39] 16 TAC § 25.62(c)(2)(A)(iii).

[40] *Id.*

[41] 16 TAC § 25.62(c)(2)(A)(iii).

that the projects included in the Plan will result in a 58% average reduction in CMI and a 76 percent average reduction in system restoration costs.

These results are quantitative evidence that the Distribution Overhead Hardening measure will be effective in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the identified resiliency events. The results further demonstrate that the Distribution Overhead Hardening measure will provide benefits for SPS customers in the form of reduced frequency and duration of customer outages, reduced system restoration costs, and improvement in the overall reliability of service.

In addition to the quantified benefits, the Distribution Overhead Hardening measure will also provide qualitative benefits for SPS customers, including improved safety, improved reliability of service during and after a resiliency event, reduced wildfire ignition risks, and reduced susceptibility to outages caused by wildfire damage, consistent with leading utility wildfire management strategies, as EDM concluded.

4. Proposed Implementation of Measure

The Resiliency Rule requires an SRP to include "implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments."[42]

SPS will conduct work in the Distribution Overhead Hardening measure throughout the duration of the SRP period, beginning in 2025 and continuing through 2028. SPS will harden approximately 170 protection zones, prioritizing projects for rebuilds based on the wildfire risk in the area and the BCR. Individual project scopes will be refined following a field review and engineering analysis prior to design and construction.

[42] 16 TAC § 25.62(c)(2)(E).

Table 9 – Distribution Overhead Hardening Implementation Distribution Circuit Hardening Rebuilds Program Estimated Scope of Work	
Activity	**Count**
Pole Replacements and Installations	**10,865 Poles Replaced**
Pole Installations (Long Span Length Mitigation)	**5,289 Poles Installed**
Pole Trussing	**1,688 Trusses**
Primary Conductor Replacements	**783 Miles**
Open Wire Secondary Replacements	**11 Miles**
Line Transformer Replacements	**515 Transformers**
Pole Wraps	**14,264 Wraps**
Wildfire Transformer Fuse Replacements	**452 Fuses**
Non-Expulsion Fuse Replacements	**173 Arrestors**

Table 10 – Distribution Overhead Hardening Budget					
Program: Distribution OH Hardening Measure	**2025**	**2026**	**2027**	**2028**	**Total Plan**
Capital	$19.5 M	$56.1 M	$75.7M	$101.7M	$253.0
O&M	$0	$0	$0	$0	$0
Total Estimated Spend	$19.5 M	$56.1 M	$75.7M	$101.7M	$253.0M

5. Metrics for Evaluating Effectiveness of Distribution Overhead Hardening Measure

The Resiliency Rule requires that "[e]ach measure in the resiliency plan must include a proposed metric or criteria for evaluating the effectiveness of that measure in preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the resiliency event it is designed to address."[43]

The metrics SPS proposes to evaluate the effectiveness of this measure include identification of underperforming areas, the average duration of outage events, average storm restoration durations, comparison of hardened vs. non-hardened protection zones, and hardened protection zone improvement. Please see Section V of this Plan for details on the evaluation metrics.

6. Reasonable Alternatives Considered

The Resiliency Rule requires that an SRP "explain the selection of each measure over any reasonable and readily-identifiable alternatives."[44]

[43] 16 TAC § 25.62(c)(2)(C).

[44] 16 TAC § 25.62(c)(2)(A)(v).

As an alternative to the Distribution Overhead Hardening measure, SPS considered overhead-to-underground conversions and staying on the same inspect, test, replace cycle supported by existing programs. When reasonably targeted, undergrounding can provide cost effective resiliency benefits to customers. As a general matter, however, undergrounding is not a cost-effective alternative to overhead hardening in most of SPS's service area. Undergrounding facilities can range from five to ten times the cost per mile of fully rebuilding the lines overhead and faces significant voltage losses as the distance between substations increases. Staying on the same inspect, test, and replace cycle that SPS operates under today would not provide the additional resiliency benefits identified by 1898 & Co. SPS identified the Distribution Overhead Hardening measure as being the most cost-effective solution for the projects selected as part of the Plan. This measure will address all issues on the protection zone at one time, whereas existing programs only identify and address point failures and miss opportunities to bring the entire zone to the current standard. This approach will reduce CMI for all customers in the protection zone, as the failure of a single asset in a protection zone results in the failure of the entire protection zone.

7. Measure Distinction from Existing Programs

Pursuant to the Resiliency Rule, if a utility's resiliency plan measures are similar to programs and measures the utility is already implementing, the plan "must distinguish the measures in the resiliency plan from these programs and measures and, if appropriate, explain how the related items work in conjunction with one another."[45]

The Wood Pole Inspection and Treatment program and the Routine Overhead Maintenance program involve periodic inspections and replacements of individual assets. These programs are intended to prevent point failures based on asset condition, not to provide comprehensive hardening for a protection zone. Circuit rebuilds under FPIP address only the worst performing feeders on the SPS system. The Distribution Overhead Hardening measure will target specific protection zones for comprehensive rebuilds to harden the entire zone against the risks posed by weather-based resiliency events and wildfire. The wildfire-specific activities in areas of heightened wildfire risk are not part of the existing programs. And because SPS is selecting protection zones

[45] 16 TAC § 25.62(c)(2)(D).

for rebuilds based on the BCR, this measure will target the facilities that provide the greatest net resiliency benefit for customers, not necessarily those with the worst historical performance.

Despite these differences, the Distribution Overhead Hardening measure will work in conjunction with the existing programs in several ways. First, work completed under the existing programs will reduce the costs associated with this measure because SPS will not replace facilities installed since 2014 that meet current standards. Second, the work completed under this measure has the potential to reduce the scope of the capital maintenance required under the existing programs because all assets in the targeted protection zones will have been upgraded to the current standard. Finally, if any circuits are selected for rebuilds under this measure that would otherwise have been eligible for improvement under FPIP, that will allow FPIP to address additional low-performing feeders.

8. Additional Information Required by the Resiliency Rule

The Resiliency Rule requires an SRP to state whether a measure (1) "is a coordinated effort with federal, state, or local government programs or may benefit from any federal, state, or local government funding opportunity"[46] or if the measure (2) "may require a transmission system outage to implement."[47]

The Distribution Overhead Hardening measure is not a coordinated effort with any federal, state, or local government program. Potential opportunities for government funding may exist in the future but none are applicable to this measure at this time.

The Distribution Overhead Hardening measure should not require any transmission outages to implement. If, however, an outage is required, SPS commits to coordinate the outage with the Southwest Power Pool.

B. Distribution System Protection Modernization

While the Distribution Overhead Hardening measure is designed to provide resilience improvement by having fewer infrastructure failures, this measure is designed to improve

[46] 16 TAC § 25.62(c)(2)(A)(iv).

[47] 16 TAC § 25.62(c)(2)(A)(vi).

absorptive capacity by decreasing the absolute impact of infrastructure failures when they occur. As explained in Section 6.2.1 of the 1898 & Co. report, improving absorptive capacity does not decrease the number of failures, but it does lessen the impact of those failures.

The Distribution System Protection Modernization measure includes two programs to reduce the customer impacts of outages: (1) Mainline Automated Reclosing Deployment and (2) Lateral Reclosing Deployment.

The Mainline Automated Reclosing Deployment program includes activities such as installing additional reclosers on the circuit to sectionalize mainline, installing reclosers at ties between circuits, installing communications equipment on existing reclosers, replacing reclosers with equipment that can accept communications, and replacing substation breakers and relay panels with modern equipment that can accept communications and be remotely operated. SPS will perform protection studies to optimize protection schemes and device placement. Additionally in heightened wildfire risk areas, SPS will install fault indicators, replace tap level fuses with non-expulsion alternatives, and modernize protection schemes. Communications-enabled relays, breakers, and reclosers installed under this program connect to SPS's ADMS through the communications upgrades completed under the Communication Modernization measure. Under the Lateral Reclosing Deployment program, SPS will install reclosers on select lateral circuits.

Details of the program activities described below outline the guidelines given to 1898 & Co. to generate project estimates. Specific project scopes will be refined following a field review and engineering analysis prior to design and construction.

Modernizing protection schemes in areas of heightened wildfire risk involves the implementation of enhanced powerline safety settings ("EPSS"), which is an industry leading protection standard in areas susceptible to wildfires. EPSS is an operational mitigation that modifies settings in relays and recloser controls on the distribution system (both within the substation and outside the substation on the feeder) to create a wildfire-specific operating mode. When EPSS is activated, relays and reclosers are more sensitive to electrical faults and react faster to those faults compared to normal device settings. When activated, EPSS also disables reclosing in relays and reclosers that would normally be set to automatically reclose after tripping because

of a fault. Ultimately, EPSS allows for powerlines to remain in service during periods of elevated wildfire risks, but with protection settings that reduce ignition risk.

SPS will perform the work in the Distribution System Protection Modernization measure on circuits with a BCR greater than or equal to 0.9. As noted in the 1898 & Co. report, their evaluation did not include an analysis of safety-related benefit streams or benefits related to reduced wildfire risks. Thus, for investments with a BCR between 0.9 and 1.0, mitigating general safety risks and other qualitative considerations provide sufficient direct benefits that the total benefits are in excess of costs. This measure will mitigate general safety risks and will also provide qualitative benefits for SPS customers in the form of wildfire risk mitigation, which will be achieved through the enabling of EPSS, addition of non-expulsion equipment, and installation of fault indicators.

Details of the program activities described below outline the guidelines given to 1898 & Co. to generate project estimates. Specific project scopes will be refined following a field review and engineering analysis prior to design and construction.

1. Resiliency Events Mitigated

The Resiliency Rule requires that, for each measure, the utility must identify "one or more risks posed by resiliency events that the measure is intended to prevent, withstand, mitigate, or more promptly recover from."[48]

Like the Distribution Overhead Hardening measure, the Distribution System Protection Modernization measure addresses the resiliency risks associated with Wind, Flood, Tornado, Winter, Heat, Cold, and Wildfire events. However, in contrast to the Distribution Overhead Hardening measure's focus on preventing and withstanding those risks, this measure will focus on mitigating and more promptly recovering, primarily through the use of reclosers and communications equipment to enable sectionalization, load transfer, and remote monitoring and control of the SPS system. This measure includes two programs: Mainline Automated Reclosing Deployment and Lateral Reclosing Deployment.

[48] 16 TAC § 25.62(c)(2)(A).

2. Description of Programs in the Distribution System Protection Modernization Measure

The Resiliency Rule requires that the resiliency plan "must be organized by measure" and include "a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure."[49] This section describes the Distribution System Protection Modernization measure in compliance with that requirement of the Rule.

2.1 Description of Mainline Automated Reclosing Deployment Program

The Mainline Automated Reclosing Deployment program includes the deployment of mainline reclosers, breakers, relays, and the controls necessary to increase sectionalization and enable automated feeder switching.[50] When an outage occurs, sectionalization minimizes the number of downstream customers initially impacted by using reclosers to isolate the fault. Automated feeder switching reconfigures the system to transfer customer load to facilities with sufficient capacity to minimize customer downtime.

Based on historical experience, SPS has estimated needing to install a minimum of one recloser every 10 circuit miles to coordinate devices and detect faults on the system. However, fewer or additional installations may be needed to optimize distribution protection schemes for sectionalization. As SPS is modernizing the protection scheme, all tie reclosers will be installed with, or upgraded to include communications capabilities. Substation upgrades will be performed at the stations that directly serve the upgraded protection schemes.

The Mainline Automated Reclosing Deployment program is comprised of eight activities described below.

[49] 16 TAC § 25.62(c)(2).

[50] The "mainline" refers to the portion of a feeder that is directly protected by the substation breaker or an automated feeder switch.

2.1.a Description of Sectionalizing Recloser Installation Activity

SPS will install additional reclosers to sectionalize mainline facilities and enhance the resiliency of the system during extreme weather events. Sectionalization provides operational flexibility and allows for shorter restoration times.

Sectionalizing the distribution system enables the isolation of faults and restoration of service to sections of the distribution system that were not directly impacted by the fault. This mitigates the impact of equipment damaged during extreme weather events, such as faults caused by broken conductor in specific sections of the distribution system. Additional reclosers on the circuit can also mitigate risks of overloading the equipment caused by extreme temperatures via redirecting power flows and transferring load between facilities.

2.1.b Description of Tie Recloser Installation Activity

SPS will install mid-point (tie) reclosers to facilitate load transfers, as depicted in Figure 4-6 of the 1898 & Co. Report. Historically, an open switch was installed between circuits and a field employee must be deployed to manually transfer load during an outage or potential overload. SPS will replace that switch with a recloser so that lines on either side of the tie point can be transferred remotely through the ADMS. As full modernization of the circuit takes place, all reclosers on the circuit will have the ability to open or close as needed to sectionalize the circuits from both directions. This will allow fewer customers to be impacted by an outage event.

2.1.c Description of Existing Recloser and Communication Replacements Activity

In addition to installing sectionalizing and mid-point (tie) reclosers, SPS will replace existing reclosers without sufficient control capabilities with equipment that can accept communications. Reclosers already equipped with communications and control capabilities will not be replaced. Necessary communications upgrades will be performed to enable remote operation and remote control of device settings.

Figure 19: Image of Existing Recloser vs. Replacement





2.1.d Description of Substation Relay Panel Replacements Activity

SPS will convert legacy electromechanical solid-state relays to microprocessor relays capable of communications and EPSS. If no RTU or modem exists at the substation, SPS will connect a cellular modem as each relay is converted.

2.1.e Description of Substation Breaker Replacements Activity

At substations where SPS is replacing or resetting relays under this measure, SPS will replace distribution circuit breakers classified as "end of life" (50+ years) as part of the same

project. This is consistent with industry practice, as it allows the entire portion of the substation to be modernized at once and better ensures the system relay and protection system as a whole will function properly. Consolidating the breaker and relay work is more cost-effective than replacing the circuit breaker on a subsequent project.

2.1.f Description of Fault Indicator Installation Activity

SPS will install wildfire fault indicators at fused tap locations in areas of heightened wildfire risk that do not currently have such capabilities. This will enhance SPS's ability to identify faulted segments during patrol following an outage or when wildfire conditions dictate alternative operating of the system.

2.1.g Description of Non-Expulsion Fuses Activity

SPS will replace tap-level fuses on circuits that are entirely or partially located in areas of heightened wildfire risk with non-expulsion alternatives to mitigate ignition risk. Non-expulsion fuses mitigate wildfire ignition risk because they do not emit sparks when they operate.

2.1.h Description of EPSS Activity

SPS will implement EPSS as a part of the modernization of settings on circuits upgraded in areas of heightened wildfire risk.

2.2 Description of Lateral Recloser Deployment Program

SPS will replace fuses with lateral reclosers in areas without heightened wildfire risk. Like the Mainline Automated Reclosing Deployment program, this program will involve installing reclosers at strategic locations on the SPS System to enhance sectionalization. However, under this program, SPS will install reclosers on lateral circuits (i.e., circuits that would be typically protected by a fuse). These devices will not remotely communicate with the ADMS, meaning SPS cannot remotely adjust automated reclosing settings or enable EPSS. In times of high wildfire risk, these are critical features of reclosers that have the ability to communicate remotely. There are no additional activities within the Lateral Recloser Deployment program.

3. Evidence of Effectiveness and Expected Benefits

The Resiliency Rule requires an SRP to "include evidence of the effectiveness of the measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the identified resiliency event."[51] Evidence that is quantitative, performance-based, or provided by an independent entity with relevant experience is afforded greater weight.[52] Further, the SRP must "explain the expected benefits of the resiliency measures including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers, and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations."[53]

SPS engaged 1898 & Co. to evaluate the effectiveness and expected benefits for the Distribution System Protection Modernization measure. 1898 & Co. comprehensively evaluated the SPS distribution system to identify potential modernization projects. Each project consists of the full set of equipment additions, upgrades, and replacements necessary to fully modernize the protection scheme on that circuit (for mainline projects) or protection zone (for lateral projects). This includes optimizing the number of customers between reclosers to maximize customer benefits. 1898 & Co. quantified the benefits for each project by recalculating historical outage

[51] 16 TAC § 25.62(c)(2)(A)(ii).

[52] *Id.*

[53] 16 TAC § 25.62(c)(2)(A)(iii).

records to account for the sectionalization, load transfer, and automated reclosing capabilities of a fully modernized circuit.

The recalculated outage records provide the quantified benefits of the measure in terms of reduced frequency or duration of outages (measured as a reduction in CMI) and avoided restoration costs. 1898 & Co. monetized the avoided CMI using the DOE ICE Calculator to calculate the BCR value for each program. The results of this analysis are provided in Section 6.2.4 of the 1898 & Co. report.

Table 11 below summarizes the results of the benefit-cost analyses for the Mainline Automated Reclosing Deployment and Lateral Reclosing Deployment projects included in the Plan.

Table 11 Distribution System Protection Modernization

Program	Average BCR	Minimum BCR	Average CMI Reduction	Avoided Restoration Costs
Mainline Automated Reclosing Deployment	4.2	0.9	37%	68%
Lateral Reclosing Deployment	1.8	0.9	21%	100%

The Mainline Automated Reclosing Deployment projects included in the Plan include all projects with a BCR of 0.9 or higher and have an average BCR of 4.2. 1898 & Co. estimates that the projects included in the Plan will result in a 37% average reduction in CMI and a 68% average reduction in system restoration costs.

The analysis shows that approximately $79.7 million, or 37 percent, of the total potential investment in the Mainline Automated Reclosing Deployment program has a BCR of 1.0 or greater. The quantified benefits for these projects are approximately $330 million, resulting in a BCR of 4.3.

These results are quantitative evidence that the Distribution System Protection Modernization measure will be effective in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by resiliency events. They demonstrate that the Distribution System Protection Modernization measure will provide benefits for SPS customers in the form of reduced outage duration, reduced system restoration costs, and improvement in the overall reliability of service.

In addition to the quantified benefits, this measure will also provide qualitative benefits for customers, including through installation of fault indicators, non-expulsion fuses, and enablement of EPSS. Customers will benefit from reduced wildfire ignition risk reduction, improved safety, and improved reliability during and after a resiliency event.

4. Proposed Implementation of Measure

The Resiliency Rule requires an SRP to include "implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments."[54]

SPS will execute the Distribution System Protection Modernization measure throughout the duration of the SRP's three-year period, beginning in 2025 and continuing through 2028. SPS will modernize approximately 151 protection zones, prioritizing projects for upgrades based on the wildfire risk in the area and the BCR. Individual project scopes will be refined following a field review and engineering analysis prior to design and construction.

[54] 16 TAC § 25.62(c)(2)(E).

Table 12 – Distribution System Protection Modernization Estimated Scope of Work		
Program	**Activity**	**Count**
Mainline Automated Reclosing Deployment	**Sectionalizing Recloser Installations**	**402 Reclosers**
	Sectionalizing Recloser Replacements	**53 Reclosers**
	Tie Recloser Installations	**226 Reclosers**
	Existing Recloser Communication Installations	**28 Communication Installs**
	Substation Relay Panel Replacements	**65 Relays Replaced**
	Substation Relay Panel Reconfigurations	**86 Relays Reconfigured**
	Substation Breaker Replacements	**16 Breakers**
	Fault Indicator Installations	**963 Fault Indicators**
	EPSS Feeder Upgrades	**151 Feeders**
	Wildfire Fuse Replacements	**2,567 Fuses**
Lateral Reclosing Deployment*	**Lateral Recloser Installation**	**62 Lateral Reclosers**

*Activity counts are based on 1898 & Co. analysis. SPS will refine project scopes following a field review and engineering analysis prior to design and construction.

Table 13 – Distribution System Protection Modernization Budget					
Program: Distribution System Protection Modernization Measure	**2025**	**2026**	**2027**	**2028**	**Total Plan**
Capital	$8.1M	$19.4M	$28.3M	$36.5M	$92.3M
O&M	$0	$0M	$0M	$0M	$0M
Total Estimated Spend	$8.1M	$19.4M	$28.3M	$36.5M	$92.3M

5. Metrics for Evaluating Effectiveness of Distribution System Protection Modernization Measure

The Resiliency Rule requires that "[e]ach measure in the resiliency plan must include a proposed metric or criteria for evaluating the effectiveness of that measure in preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the resiliency event it is designed to address."[55]

The metrics SPS proposes to evaluate the effectiveness of this measure include identification of underperforming areas, the average duration of outage events, and average storm restoration durations. Please see Section V of this Plan for details on the evaluation metrics.

6. Reasonable Alternatives Considered

The Resiliency Rule requires that an SRP "explain the selection of each measure over any reasonable and readily-identifiable alternatives."[56]

No viable and cost-effective alternatives exist to sectionalize the distribution system. The 1898 & Co. analysis considered various alternatives around the level of sectionalization (customer pod size) and the number of reclosers needed to optimize protection schemes and provide the maximum customer benefit that is technically feasible. SPS selected the optimal configuration for each circuit.

7. Measure Distinction from Existing Programs

Pursuant to the Resiliency Rule, if a utility's resiliency plan measures are similar to programs and measures the utility is already implementing, the plan "must distinguish the measures in the resiliency plan from these programs and measures and, if appropriate, explain how the related items work in conjunction with one another."[57]

The Distribution System Protection Modernization Measure will work in conjunction with the FLISR program, which is described in Section III.C above. In December 2021, SPS activated the ADMS, which has many core and advanced functions that include FLISR. SPS began its multi-

[55] 16 TAC § 25.62(c)(2)(C).

[56] 16 TAC § 25.62(c)(2)(A)(v).

[57] 16 TAC § 25.62(c)(2)(D).

year deployment of FLISR in 2023, including the deployment of additional automated field devices such as reclosers that are integrated with the ADMS. FLISR reviews and selects projects for upgrades based strictly on the historical performance of the mainline of the feeder.

The work proposed in the Distribution System Protection Modernization measure is incremental to FLISR work and will broaden SPS's deployment of communications-enabled field devices to circuits with demonstrated net benefits for customers. This measure also includes additional work in the substation that is not part of the FLISR program.

8. Additional Information Required by the Resiliency Rule

The Resiliency Rule requires an SRP state whether a measure (1) "is a coordinated effort with federal, state, or local government programs or may benefit from any federal, state, or local government funding opportunity[58] or if the measure (2) "may require a transmission system outage to implement."[59]

The Distribution System Protection Modernization measure is not a coordinated effort with any federal, state, or local government program. Potential opportunities for government funding may exist in the future but none are applicable to this measure at this time.

The work performed under this measure should not require any transmission outages to implement. If, however, a transmission outage is required, SPS commits to coordinate the outage with Southwest Power Pool.

C. Communication Modernization

The Resiliency Rule requires that the resiliency plan "must be organized by measure" and include "a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure."[60] This section provides a description of the Communication Modernization measure in compliance with that requirement of the Rule.

[58] 16 TAC § 25.62(c)(2)(A)(iv).

[59] 16 TAC § 25.62(c)(2)(A)(vi).

[60] 16 TAC § 25.62(c)(2).

The Communication Modernization measure consists of investments in private communications infrastructure to modernize SPS's operational technology ("OT") communications, including building out a private LTE ("pLTE") cellular network. Modernizing communication and protection systems is a high priority for SPS. The proliferation of connected devices presents exciting opportunities to provide value for customers through applications such as automated switching, EPSS, and advanced metering. These devices require a reliable, and reliably available, communications network to connect them to SPS's ADMS. Unfortunately, public cellular networks provide inadequate coverage across much of SPS's rural, sparsely populated service area to deploy the devices on a widespread basis. Additionally, reliance on a third-party cellular network presents cybersecurity risks for SPS's critical infrastructure.

Building out a pLTE network is essential to fully enable the operational capabilities of the protective relays, breakers, and reclosers proposed in the Distribution System Protection Modernization measure. Without it, these devices cannot communicate with the ADMS or be remotely monitored or controlled. Migrating system communications to a pLTE network will also make the SPS system more resilient and secure against the threat of cyber-attacks because SPS will maintain visibility and control over network access, data traffic, and security protocols.

In designing the Communication Modernization measure, SPS considered: (1) the technology enhancements needed to fully deploy new capabilities across the SRP, (2) the level of investment needed to support the other resiliency measures; and (3) SPS's long-term objectives for OT and system communications and existing capabilities gaps.

In addition to the investments in pLTE infrastructure, the Communication Modernization measure includes supporting investments in optical ground wire ("OPGW"), to provide data transport (i.e., "backhaul") between the pLTE network and the ADMS, and remote terminal units ("RTUs"), to provide visibility into substation operations.

1. Resiliency Events Mitigated

The Resiliency Rule requires that, for each measure, the utility must identify "one or more risks posed by resiliency events that the measure is intended to prevent, withstand, mitigate, or more promptly recover from."[61]

The Communication Modernization measure mitigates resiliency risks associated with Wind, Flood, Tornado, Winter, Heat, Cold, and Wildfire events by enabling the remote monitoring and control of the protective devices proposed under the Distribution System Protection Modernization measure. This measure also mitigates cybersecurity resiliency risks.

2. Description of Program in the Communication Modernization Measure

The Resiliency Rule requires that the resiliency plan "must be organized by measure" and include "a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure."[62] This section provides a description of the Communication Modernization measure in compliance with that requirement of the Rule.

Under this measure, SPS will invest in private communications infrastructure to extend pLTE and private fiber networks across its service area. These investments are critical to SPS's long-term objectives for resiliency, wildfire mitigation, and cybersecurity. SPS will construct 49 new pLTE towers at existing SPS substations and microwave installations, add approximately 83 miles of new OPGW and install 4 RTUs to terminate the OPGW. The RTUs will be installed at SPS substations with a pLTE tower to provide backhaul between the pLTE network and the ADMS.

The pLTE network, private fiber network, and public carrier network, which will continue to be used as a backup, will provide three layers of redundancy to prevent any single event from disrupting SPS's system communications. The RTUs will provide visibility into system conditions and remote-control capabilities at the substations where they are installed.

[61] 16 TAC § 25.62(c)(2)(A).

[62] 16 TAC § 25.62(c)(2).

The pLTE network will increase communications availability, provide greater visibility into the state of the SPS electric system, enable remote operation and control of connected devices, and allow SPS to exercise greater control over network security and reliability. Existing public carrier networks do not provide coverage across large portions of SPS's service area. This prevents SPS from being able to effectively deploy communications-enabled devices such as protective relays, breakers, and reclosers in these areas. These protective devices are central to SPS's efforts to make the system more resilient. Connected reclosers can be remotely controlled to sectionalize the distribution system, isolate faults, and transfer customer load when a thunderstorm, ice storm, or other resiliency event causes an outage. Communicating relays allow SPS to remotely monitor system conditions and activate EPSS settings to mitigate wildfire ignition risks. In order to provide these capabilities, devices need access to a secure, reliable communications network.

In addition to the benefits for weather-based resiliency events and wildfire, the Communication Modernization measure will also make SPS's OT communications, and therefore SPS's electric system, more secure against risks posed by cybersecurity threats.

Sending system communications through public networks makes SPS reliant on third-party carriers to adequately secure their network communications. SPS's data is not prioritized, and once data is transmitted, SPS loses the ability to monitor it until it is received by SPS's backend systems.

Migrating to the pLTE network will subject communications to SPS's robust cybersecurity protections. Bad actors will have fewer attack vectors to infiltrate the network because only approved devices will have access. SPS will implement rogue-device protection to prevent unauthorized access, as well as encryption and multi-factor authentication to make end-use devices more secure. The network will be protected by end-to-end monitoring of all data traffic and devices and will be a zero-trust environment, allowing SPS to implement additional security controls such as Internet Protocol Security (IPSec) tunnels to encrypt and authenticate data traffic. These security measures will prevent or mitigate potential cyber-threats from disrupting the safe and reliable operation of the SPS electric system.

The Communication Modernization measure is comprised of a single program: Private Circuit Communications Deployment, which program includes three distinct activities.

2.1 Description of Activities within the Private Circuit Communications Deployment Program

2.1.a Private LTE Network Buildout

The pLTE network buildout consists of 49 pLTE tower installations. This work is intended to provide coverage in areas of high wildfire risk, enabling device connection where previously not possible. The following figures show the planned locations of the proposed pLTE towers and network coverage over SPS's distribution system:

Figure 20 – Texas North

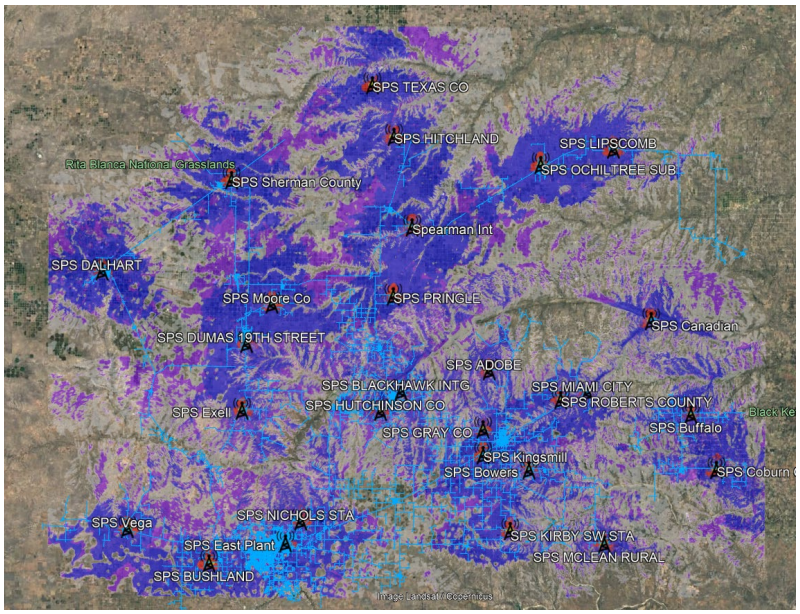
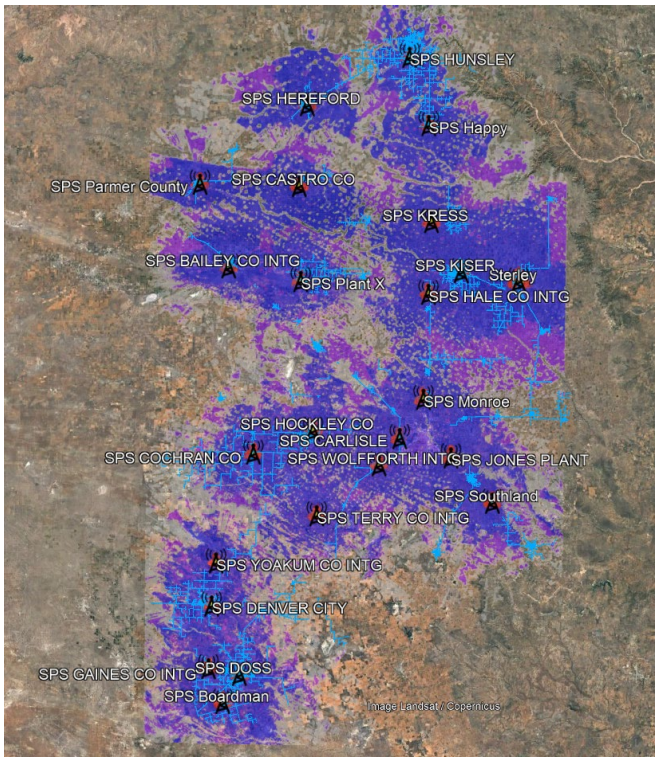


Figure 21 – Texas South



2.1.b Private Fiber Optic

Private fiber provides high-speed and reliable backhaul communication from pLTE towers to the core network. SPS will install OPGW, a type of private fiber optic cable, on transmission lines, terminating into RTUs at substations where pLTE towers are installed.

2.1.c RTU Installation

SPS will install RTUs where not already existing to enable data transmission to the control center. This work is necessitated by pLTE deployment and is incremental to SPS's existing OPGW and RTU installation plan.

3. Evidence of Effectiveness and Expected Benefits

The Resiliency Rule requires an SRP to "include evidence of the effectiveness of the measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the identified resiliency event."[63] Evidence that is quantitative, performance-based, or provided by an independent entity with relevant experience is afforded greater weight.[64] Further, the SRP must "explain the expected benefits of the resiliency measures including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers, and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations."[65]

SPS engaged 1898 & Co. to evaluate the effectiveness and expected benefits for the Communication Modernization measure.

The benefits of this measure are twofold: (1) it will make the SPS system more secure against cybersecurity risks and (2) it will unlock the full benefits of the communications-enabled protective devices installed under the Mainline Automated Reclosing Deployment program.

First, migrating communications from third-party cellular carriers to pLTE will make the SPS system more secure against cyber-attacks by allowing SPS to monitor and maintain control

[63] 16 TAC § 25.62(c)(2)(A)(ii).

[64] *Id.*

[65] 16 TAC § 25.62(c)(2)(A)(iii).

over network access and data traffic. The pLTE network will also make the SPS system more secure by providing a third layer of redundancy for communications, in addition to the public cellular and private fiber networks, preventing any single event from disrupting system communications.

The Communication Modernization measure will also benefit customers by enabling the full benefits of the investments proposed under the Mainline Automated Reclosing Deployment program. SPS's ability to fully and effectively utilize communications-enabled protective devices requires the investment in a pLTE network. Accordingly, 1898 & Co. modeled the costs and benefits for the Communication Modernization measure and Mainline Automated Reclosing Deployment program together, calculating a combined BCR of 1.8. In other words, the customer benefits of combining the Mainline Automated Reclosing Deployment program and the Communication Modernization measure, including a reduction in the frequency or duration of outages, reduced system restoration costs, and improvement in general reliability, are almost double their combined investment costs.

In addition to these quantified benefits, the Communication Modernization measure will provide qualitative benefits for SPS customers, including protecting the SPS system against cybersecurity threats and reducing wildfire ignition risk by providing the communications required to remotely monitor and control field devices and remotely enable EPSS.

4. Proposed Implementation of Measure

The Resiliency Rule requires an SRP to include "implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments."[66]

SPS will begin building out its pLTE and private fiber networks under this measure in 2025 and continue throughout the three-year implementation period. This is anticipated to include erecting 49 pLTE towers at existing SPS substations and microwave installations, stringing 83

[66] 16 TAC § 25.62(c)(2)(E).

miles of OPGW on existing transmission lines, installing 4 RTUs at existing SPS substations, and terminating the OPGW into the newly installed RTUs (6 terminations in total). The planned implementation schedule is provided in the table below.

Table 14 – Communication Modernization Implementation

	2025	2026	2027	2028	Total Plan
PLTE Towers	0	16	15	18	49
OPGW Line Miles	0	7	44	32	83
RTU Installations	0	1	2	1	4
OPGW Terminations	0	2	2	2	6

The total estimated cost for the Communication Modernization measure is $112.6 million. There is no incremental O&M associated with the proposed Communication Modernization investments.

Table 15 – Communication Modernization Budget

	2025	2026	2027	2028	Total Plan
Capital	$0M	$34.2M	$37.0M	$41.4M	$112.6M
O&M	$0M	$0M	$0M	$0M	$0M
Total Estimated Spend	$0M	$34.2M	$37.0M	$41.4M	$112.6M

*SPS does not currently anticipate incurring any costs for this measure in 2025. However, depending on the timing of SRP approval, SPS may begin initial engineering work in late 2025.

5. Metrics for Evaluating Effectiveness of Communication Modernization Measure

The Resiliency Rule requires that "[e]ach measure in the resiliency plan must include a proposed metric or criteria for evaluating the effectiveness of that measure in preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the resiliency event it is designed to address."[67]

The metrics SPS proposes to evaluate the effectiveness of this measure are the completion of cellular tower construction and the connectivity of end devices on the cellular network. Please see Section V of this Plan for details on the evaluation metrics.

6. Reasonable Alternatives Considered

The Resiliency Rule requires that an SRP "explain the selection of each measure over any reasonable and readily-identifiable alternatives."[68]

There are few alternatives to a private network for communicating with field devices in areas with inadequate public cellular coverage. Installing repeaters to extend a public cellular signal is not scalable given the size of SPS's distribution system. Even if it were, the costs to connect each repeater and protective device connected to the network would likely make this option cost-prohibitive. Another alternative is to restrict SPS's deployment of communications-enabled protective devices to areas with adequate cellular coverage. This alternative is unacceptable because it would prevent SPS from providing many of its customers with the resiliency benefits of distribution automation and EPSS. Further, relying on third-party providers for OT communications is a less secure alternative for the reasons described above. SPS also considered partnering with public cellular providers for alternative solutions, but their solutions are still evolving and focus on usage/data plans, resulting in high O&M costs.

The only viable alternative to RTU installation is to install a cellular modem to connect each relay. This alternative would fail to capitalize on the existing OPGW infrastructure, is not

[67] 16 TAC § 25.62(c)(2)(C).

[68] 16 TAC § 25.62(c)(2)(A)(v).

financially viable, and would still require a public cellular network. There are no viable alternatives to OPGW backhaul.

7. Measure Distinction from Existing Programs

Pursuant to the Resiliency Rule, if a utility's resiliency plan measures are similar to programs and measures the utility is already implementing, the plan "must distinguish the measures in the resiliency plan from these programs and measures and, if appropriate, explain how the related items work in conjunction with one another."[69]

SPS has been deploying private fiber for communications between substations and control systems, as well as microwave installations for point-to-point communications for many years. These solutions provide a different set of capabilities from pLTE and neither can feasibly provide communications to field devices across the distribution system.

SPS currently relies on circuit-level communications and public cellular networks to enable communication between devices across most of its system. These solutions will continue to play a role in providing backup communications or communications in areas not covered by the pLTE network. The Communication Modernization measure is distinct from these approaches because it involves development of an integrated private communications network.

SPS recently began initial development of its pLTE network. One tower was recently activated and will begin connecting to devices in late 2024 or early 2025. The second tower is expected to be activated in 2025. These are the only two pLTE installations currently planned, and neither is included in the 49 towers proposed in the SRP. SPS is unlikely to build any additional towers outside of the SRP until at least 2029. A deployment at the scale proposed in the SRP would take many years beyond that.

8. Additional Information Required by the Resiliency Rule

The Resiliency Rule requires an SRP to state whether a measure (1) "is a coordinated effort with federal, state, or local government programs or may benefit from any federal, state, or local

[69] 16 TAC § 25.62(c)(2)(D).

government funding opportunity"[70] or if the measure (2) "may require a transmission system outage to implement."[71]

The Communication Modernization measure is not a coordinated effort with any federal, state, or local government program, and SPS will not benefit from any government funding opportunities in completing this work.

Installation of the OPGW will require transmission outages. The other activities within this measure should not require transmission outages. SPS commits to coordinate all outages with SPP.

D. Operational Flexibility

The Resiliency Rule requires that the resiliency plan "must be organized by measure" and include "a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure."[72] This section provides a description of the Operational Flexibility measure in compliance with that requirement of the Rule.

The Operational Flexibility measure consists of two programs that will make the SPS system more resilient by providing additional flexibility in managing power disruptions when an outage occurs. Under the Mobile Substation Equipment Procurement program, SPS will procure additional mobile substation equipment to enable quicker restoration of power during equipment failures at SPS substations. Under the Installation of Transmission Switches programs, SPS will install additional transmission switches to increase SPS's ability to sectionalize and isolate faults on the transmission system, reducing the customer impacts of outages and accelerating service restoration for customers by isolating damaged sections. These programs will allow SPS to mitigate and more promptly recover from outages caused by resiliency events.

1. Resiliency Events Mitigated

The Resiliency Rule requires that, for each measure, the utility must identify "one or more risks posed by resiliency events that the measure is intended to prevent, withstand, mitigate, or more

[70] 16 TAC § 25.62(c)(2)(A)(iv).

[71] 16 TAC § 25.62(c)(2)(A)(vi).

[72] 16 TAC § 25.62(c)(2).

promptly recover from."[73] This section identifies the resiliency events the Operational Flexibility measure is proposed to address.

The Operational Flexibility Measure is designed to mitigate and more promptly recover from the risks posed by weather-based resiliency events, including Wind, Flood, Tornado, Winter, Heat and Cold events. Specifically, this measure will address risks that result in outages on the transmission system and at SPS substations.

2. Description of Programs in the Operational Flexibility Measure

The Resiliency Rule requires that the resiliency plan "must be organized by measure" and include "a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure."[74] This section provides a description of the Overhead Hardening Measure in compliance with that requirement of the Rule.

The Operational Flexibility measure is comprised of two programs: Mobile Substation Equipment Procurement and Installation of Transmission Switches.

2.1 Description of Mobile Substation Equipment Procurement Program

SPS will procure additional mobile substation equipment to better ensure that adequate inventory is available across a variety of equipment types, voltage ratings, and capacity ratings to respond to a wide range of failures and events. Mobile substation equipment includes the transformers, circuit switchers, and voltage regulators that allow SPS to quickly respond to a substation outage while a permanent repair or replacement is undertaken. Mobile substation equipment is typically mounted on a trailer so that it can be mobilized and delivered to the site quickly.

Any weather-based resiliency event that damages a substation can potentially cause damage or destruction of the substation transformer. When this happens, mobile substation equipment is often the only means to quickly restore service to customers. This is particularly

[73] 16 TAC § 25.62(c)(2)(A).

[74] 16 TAC § 25.62(c)(2).

important for customers served from a single transformer, whose load cannot be transferred to an alternate substation.

Maintaining a sufficient supply of mobile substation equipment of the appropriate voltages and capacities allows SPS to restore service in the time it takes to deploy, connect, test, and energize the mobile unit—typically about 18-24 hours. Permanent repairs or replacements of substation transformers often take months to complete, and procurement lead times for substation transformers have increased significantly over the last several years. Lead times that were in the range of 10-18 months just a few years ago are now typically 24-36 months, resulting in longer timelines to plan a replacement for equipment once the replacement decision is made. Longer lead times mean a larger inventory of mobile substation equipment is necessary to provide the tools and flexibility needed to quickly respond to outages caused by resiliency events.

SPS already operates mobile substation equipment but has identified the need for additional equipment. Procuring the equipment proposed under this program will allow SPS to respond to resiliency events even when existing units are deployed for service restoration or capital projects. Over the past three years, SPS has employed an average of 20 mobile substation installations per year. This is up from previous years due to existing equipment age, material lead times, updates to employee safe-working distances, and other factors.

A larger fleet of mobile substation equipment will also support resiliency by increasing SPS's ability to complete the work proposed in this Plan efficiently and with minimal disruption to customers. Many of the substations proposed for investment under the SRP measures are islanded, without adequate ties to transfer the customer load to other assets. SPS will deploy mobile substation equipment to reduce the number of customer outages required to perform the work. For example, Van Buren Substation has four feeders identified for relay and breaker replacements as part of the Distribution System Protection Modernization measure. Mobile substation equipment will be required to efficiently complete the replacements and not introduce additional risk for customers while the work is completed.

Overall, increased mobile equipment quantities help ensure that SPS can respond to resiliency events quickly, can respond to more events—and more widespread events—

simultaneously, and can execute on its proposed SRP investments with reduced disruption to customers.

2.2 Description of Installation of Transmission Switches Program

SPS will install new disconnect switches on selected transmission lines. SPS has performed a review to identify optimal locations for new switches. These new switch locations were chosen based on the distances to existing sectionalizing equipment and the availability of switching options on circuits that serve distribution substations. The chosen locations currently have very limited options when switching around failed assets and storm damage.

Disconnect switches are installed on transmission lines to increase system flexibility and to allow for sectionalization, similar to the distribution system reclosers proposed under the Distribution System Protection Modernization measure. Transmission switches bolster system resiliency by decreasing the number of customers that may lose power during a resiliency event. For example, if a tornado damages part of a transmission line, disconnect switches can allow SPS to reconfigure the system, restoring service to undamaged portions of the transmission system and substations they feed. If a substation is deenergized, all distribution customers who take service from that station and cannot be transferred to adjacent infrastructure are subject to an outage.

Switches also provide a means to segment a transmission line to reduce the amount of transmission line that needs to be deenergized to perform the necessary work. This is beneficial for emergency response in the case of resiliency events and for planned work. When repairs are complete, transmission switches also allow for a faster and more controlled restoration process. For example, disconnect switches can simply be closed rather than having additional outages to physically install connections.

3. Evidence of Effectiveness and Expected Benefits

The Resiliency Rule requires an SRP to "include evidence of the effectiveness of the measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the identified resiliency event."[75] Evidence that is quantitative, performance-based, or provided

[75] 16 TAC § 25.62(c)(2)(A)(ii).

by an independent entity with relevant experience is afforded greater weight.[76] Further, the SRP must "explain the expected benefits of the resiliency measures including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers, and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations."[77]

The Operational Flexibility measure will help the SPS transmission and distribution system prevent, withstand, mitigate, or more promptly recover from the risks posed by extreme weather events. The programs in this measure include industry-standard investments and activities commonly used by electric utilities.

The U.S. Department of Energy ("DOE") recognizes that mobile substation equipment is an effective means of rapidly restoring electric service.[78] In a report on the benefits of mobile substation equipment, the DOE noted that the flexibility of being able to relatively easily deploy mobile substations for various tasks justifies utility ownership of mobile transformers.[79] The DOE report also concludes that mobile substation equipment can play a critical role in reestablishing grid connection to provide rapid restoration of service.[80] The Mobile Substation Equipment Procurement program will make use of these capabilities to mitigate and more promptly recover from resiliency events that damage or destroy a substation transformer.

The Mobile Substation Equipment Procurement program will reduce the frequency and duration of customer outages by giving SPS additional tools to quickly restore service to customers when a resiliency event damages or destroys a substation transformer. It will also improve overall service reliability for customers, as SPS will be able to deploy the mobile substation equipment to

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[76] *Id.*

[77] 16 TAC § 25.62(c)(2)(A)(iii).

[78] *See U.S. Department of Energy, Benefits of Using Mobile Transformers and Mobile Substations for Rapidly Restoring Electrical Service* (Aug. 2006), *available at* https://www.energy.gov/oe/articles/benefits-using-mobile-transformers-and-mobile-substations-rapidly-restoring-electrical

[79] *Id.* at 9.

[80] *Id.* at 26.

maintain continuity of service during maintenance of substation facilities that would otherwise require an outage.

The Installation of Transmission Switches program will allow SPS to withstand, mitigate, and more promptly recover from outages caused by a fault on the transmission system. Transmission switches are commonly used by electric utilities to sectionalize the transmission system and isolate faults. The Installation of Transmission Switches program will reduce the frequency and duration of customer outages, reduce system restoration costs, and improve overall service reliability for customers by expanding SPS's ability to quickly reconfigure the transmission system without the need to deploy SPS personnel to perform manual switching. The additional transmission switches installed under this program will also provide safety benefits by reducing the exposure of SPS personnel to energized facilities.

4. Proposed Implementation of Measure

The Resiliency Rule requires an SRP to include "implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments."[81]

SPS will procure six mobile substations, one mobile circuit switcher, and one mobile regulator under the Mobile Substation Equipment Procurement program. SPS will stage the mobile substation equipment in locations across its service area to provide substation outage support. Under the Installation of Transmission Switches program, SPS will install 17 switching devices, including 14 loadbreak switches and 3 non-loadbreak switches. Individual project scopes will be refined following a field review and engineering analysis prior to design and construction.

Transmission line outages are typically required to install transmission switches. During installation, SPS will use temporary "shoo-fly" line configurations or mobile substations to reroute power around the affected section of the transmission line, minimizing downtime that could result in outages for SPS customers.

[81] 16 TAC § 25.62(c)(2)(E).

The estimated cost of the Mobile Substation Equipment Procurement program is approximately $30.8 million. The estimated cost for the Installation of Transmission Switches program is approximately $12.8 million, including approximately $6,000 in incremental O&M expense.

Table 16 – Operational Flexibility Implementation Budget					
Operational Flexibility	**2025**	**2026**	**2027**	**2028**	**Total Plan**
Capital	$3.1M	$10.1M	$23.8M	$6.7M	$43.7M
O&M			$0.002M	$0.004M	$0.006M
Total Estimated Spend	$3.1M	$10.1M	$23.8M	$ 6.7	$43.7M

5. Metrics for Evaluating Effectiveness

The Resiliency Rule requires that "[e]ach measure in the resiliency plan must include a proposed metric or criteria for evaluating the effectiveness of that measure in preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the resiliency event it is designed to address."[82]

The metric SPS proposes to evaluate the effectiveness of this measure is the average duration of outage events. Please see Section V of this Plan for details on the evaluation metric.

6. Reasonable Alternatives Considered

The Resiliency Rule requires that "[e]ach measure in the resiliency plan must include a proposed metric or criteria for evaluating the effectiveness of that measure in preventing,

[82] 16 TAC § 25.62(c)(2)(C).

withstanding, mitigating, or more promptly recovering from the risks associated with the resiliency event it is designed to address."[83]

Mobile Substation Equipment:

Installing field ties or redundant transformers are viable alternatives to mobile transformers in a technical sense, but there are several reasons why these solutions are not financially viable. First, field ties require extensive distribution infrastructure investments which are typically not cost-justified in small, rural communities that today are served by a single substation. Installing redundant transformers presents similar challenges. Mobile substation equipment offers the desired benefits in a more cost-effective and flexible manner, as one mobile transformer can provide service restoration to multiple locations. Mobile substation equipment can be deployed quickly and moved to different sites as needs arise, making them a more attractive option than installing more costly permanent infrastructure primarily to provide backup service.

Installation of Transmission Switches:

The only alternative to installing switches on transmission facilities is deploying field resources to manually disconnect the line, which often requires crews to physically contact an energized line. Installing switches limits the exposure of SPS field crews to energized equipment and allows for faster switching when compared to the manual alternative.

7. Measure Distinction from Existing Programs

Pursuant to the Resiliency Rule, if a utility's resiliency plan measures are similar to programs and measures the utility is already implementing, the plan "must distinguish the measures in the resiliency plan from these programs and measures and, if appropriate, explain how the related items work in conjunction with one another."[84]

Mobile Substation Equipment Procurement:

This program will expand SPS's existing fleet of mobile substation equipment and provide SPS with additional tools and greater flexibility to respond to resiliency events, planned

[83] 16 TAC § 25.62(c)(2)(C).

[84] 16 TAC 25.62(c)(2)(D).

maintenance, and capital projects across the SPS service area that could otherwise result in a substation outage.

Installation of Transmission Switches:

SPS's current transmission switch installation work addresses: (1) the replacement of existing switches due to age or defect through End of Life Replacement and (2) installations on newly installed taps. SPS does not have an existing program to proactively install transmission switches on existing transmission facilities. This program is incremental to the existing work and provides added resilience benefits to the existing system by reducing the number of customers exposed to an outage on the transmission system.

8. Additional Information Required by the Resiliency Rule

The Resiliency Rule requires an SRP state whether a measure (1) "is a coordinated effort with federal, state, or local government programs or may benefit from any federal, state, or local government funding opportunity"[85] or if the measure (2) "may require a transmission system outage to implement."[86]

The Operational Flexibility measure is not a coordinated effort with any federal, state, or local government program, and SPS will not benefit from any government funding opportunities in completing this work.

The Installation of Transmission Switches program will likely require transmission outages as switches are replaced on the transmission system. SPS commits to coordinate all outages with Southwest Power Pool. No transmission system outages will be required to implement the Mobile Transformer Inventory procurement program.

[85] 16 TAC § 25.62(c)(2)(A)(iv).

[86] 16 TAC § 25.62(c)(2)(A)(vi).

E. Wildfire Mitigation

The Resiliency Rule requires that the resiliency plan "must be organized by measure" and include "a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure."[87] This section provides a description of the Wildfire Mitigation measure in compliance with that requirement of the Rule. Other wildfire related activities in other measures of the SRP are:

- Distribution Overhead Hardening
- Conductor Replacements
- Line Transformer Replacements
- Wildfire Pole Wraps
- Wildfire Ignition Fuse Replacements
- Wildfire Arrestor Replacements
- Distribution System Protection Modernization
- Fault Indicator Installation
- EPSS
- Lateral Recloser Deployment
- Communication Modernization
- Private LTE Network Buildout

This measure improves and enhances system resiliency by providing SPS with greater awareness of the wildfire risks facing its system and mitigating potential ignition sources and risks posed by wildfires to the SPS System and the communities it serves. In developing this measure, SPS has engaged with outside partners to assess wildfire risks, develop mitigation programs, and conduct an independent review of the proposed programs under this measure.

To understand the wildfire risk facing its service area, SPS engaged EDM to advise regarding wildfire risk in the SPS service area and to develop a geospatial wildfire risk map of its service area. The Wildfire Risk Map depicts areas of elevated wildfire risk by tier. Using the

[87] 16 TAC § 25.62(c)(2).

Wildfire Risk Map, SPS is better able to understand the areas most vulnerable to wildfire risk and where to prioritize spending to optimize risk mitigation.

There are two programs under the Wildfire Mitigation measure of the SRP: (1) Wildfire Situational Awareness and (2) Wildfire Physical Mitigations. The Wildfire Situational Awareness program includes activities that are intended to help SPS assess its wildfire risk by monitoring forecasted and real time fire danger and fire weather conditions and monitoring of SPS assets and to better understand wildfire risk on the landscape relative to populated areas and SPS facilities. The Wildfire Physical Mitigation program encompasses activities that help SPS mitigate potential utility ignition sources (prevention) and physical risks to the equipment used in its service area from passing wildfire (protection).

The information provided by the situational awareness tools described below provides SPS with timely (and often real time) information about physical and environmental threats, including active, potential, and expected threats. This information provides analysts what they need to proactively respond, assess correlated information, and make decisions to minimize damage and impact to operations thus creating a more resilient system.

As part of SPS's wildfire risk assessment and the development of the Wildfire Operations Map, discussed above in Section II.B, SPS determined that it will prioritize and implement its Physical Mitigations activities in the areas of heightened wildfire risk located in its service territory (i.e., Tiers 2 and 3). The Wildfire Operations Map and Tiers are described in more detail below.

1. Resiliency Events Mitigated

The Resiliency Rule requires that, for each measure, the utility must identify "one or more risks posed by resiliency events that the measure is intended to prevent, withstand, mitigate, or more promptly recover from."[88]

This measure is designed to improve and enhance SPS's system resiliency and mitigates risks posed by wildfires. A detailed description of the impact and recurrence of wildfire in SPS's

[88] 16 TAC § 25.62(c)(2)(A).

service area was developed in collaboration with EDM in preparation of this SRP and is provided in Section III.B and in additional detail below.

2. Description of Programs in the Wildfire Mitigation Measure

The Resiliency Rule requires that the resiliency plan "must be organized by measure" and include "a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure."[89] This section provides a description of the Communication Modernization measure in compliance with that requirement of the Rule.

The Wildfire Mitigation measure is comprised of two programs: Wildfire Situational Awareness and Wildfire Physical Mitigation.

2.1 Description of Wildfire Situational Awareness Program

Situational Awareness is a recognition of existing and potential "burning conditions" related to the environment. Awareness of these burning conditions is necessary for effective resiliency event preparation, pre-planning, and response. Specific to SPS's Wildfire Mitigation measure, situational awareness is SPS's ability to perceive, understand, and respond to hazardous conditions associated with wildfire weather, wildfire danger, and fire on the landscape that can impact the safety and resiliency of SPS's electric system. SPS's Situational Awareness measure includes several programs designed to improve its ability to forecast and monitor in real time and thoroughly understand the unique environments and micro-climates in its service area so that it can rapidly respond to and mitigate the threat of wildfire. The Situational Awareness programs under the Wildfire Mitigation measure of the SRP include: (1) Wildfire Risk Maps, (2) Enhanced Meteorology Capabilities, (3) Weather and Fire Science Modeling, and (4) Artificial Intelligence ("AI") Cameras. These programs are described below.

2.1.a Description of Wildfire Risk Map Activity

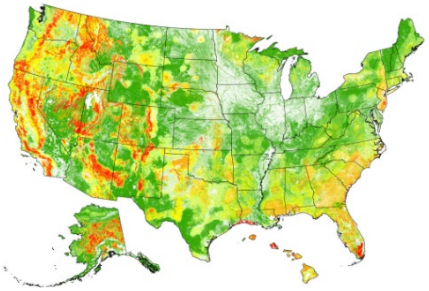
SPS engaged wildfire subject matter experts at EDM to develop the aforementioned geospatial Wildfire Risk Map outputs specific to SPS's service area that are versatile and useful

[89] 16 TAC § 25.62(c)(2).

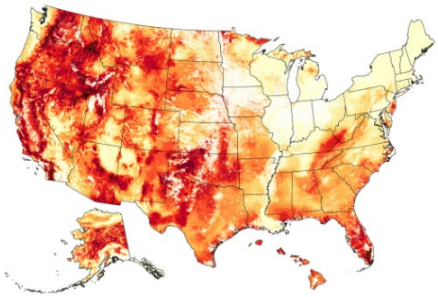
for helping SPS better understand its fire risk on the landscape relative to developed/populated areas and its facilities and to assist with the prioritization and operationalizing of its various wildfire mitigation efforts. Below are the key features and aspects of the Wildfire Risk Map outputs:

- Provides a landscape view of wildfire hazards, including a compiled and weighted evaluation of landscape and population wildfire risk to match local variables for SPS's service area and assets
- Provides up to date modeling of population and structure risk
- Provides a drilled down presentation of wildfire risk in hexagonal one-acre grid capture
- Designed for utility purposes and localized specific to SPS and its assets, including:
    - Overhead electric transmission and distribution
    - Substations
    - Generation sites
    - Gas transmission and distribution
- Encompasses a 10-mile buffer on each side of the centerline and around SPS assets that provides a wider view of the surrounding areas that could be impacted by fire on the landscape
- Provides defined, weighted, valued, and geospatially visualized wildfire adjective class risk ratings
- Leverages defensible, high quality, publicly available data that are vetted and curated from various government agencies and reputable private sources
- Provides a versatile and updatable data repository with various layers that can be turned on or off for a variety of analyses

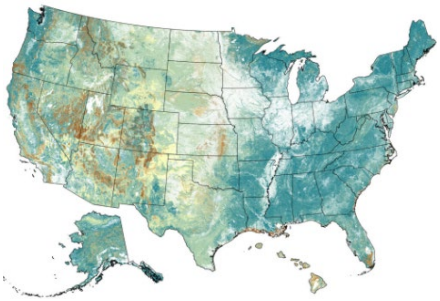
In order to develop the Wildfire Risk Map outputs, baseline datasets from wildfirerisk.org ("WRO") were utilized. These data sets are created by the U.S. Department of Agriculture Forest Service ("USFS") at the direction of Congress for the express purpose of providing guidance and mitigation prioritization assistance to elected officials, land use planners, fire managers, and the like. The following baseline data were leveraged in the development of SPS's Wildfire Risk Map products:



Wildfire Hazard Potential - WHP: "An index that quantifies the relative potential for high-intensity wildfire that may be difficult to manage that serves as a measure to help prioritize where fuel treatments may be needed."[90]



Burn Probability - BP (or Wildfire Likelihood): "The annual probability of wildfire burning in a specific location."[91]

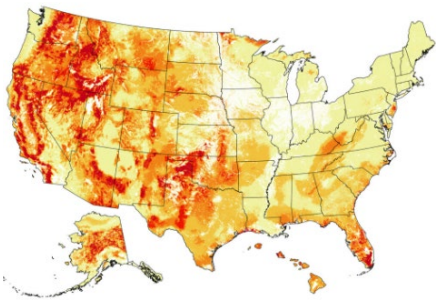


Conditional Flame Length – CFL: "Most likely flame length at a given location if a fire occurs, based on all simulated fires; an average measure of wildfire intensity."[92]

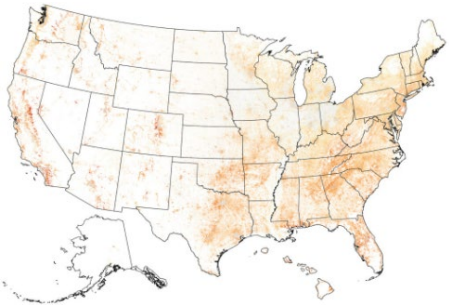
[90]Wildfire Risk to Communities, USFS (2024), *available at* https://wildfirerisk.org/download/.

[91] *Id.*

[92] *Id.*



Risk to Potential Structures - RPS (or Risk to Homes): A measure that integrates wildfire likelihood and intensity with generalized consequences to a home on every pixel. For every place on the landscape, it poses the hypothetical question, "What would be the relative risk to a house if one existed here?"[93]



Housing Unit Risk – HU Risk: "This layer incorporates all primary elements of wildfire risk. It integrates wildfire likelihood and intensity with the generalized susceptibility of homes, and it also incorporates housing density."[94]

Using these baseline data, four Wildfire Risk Map outputs representing the geospatial categorizations of wildfire hazards coincident with SPS's service area were developed, namely the:

- Hazardous Fire Areas (HFAs): A fundamental and more granular geospatial representation of landscape/population wildfire risk split into six risk classifications.
- Fire Tiers: Aggregated from the six HFAs, the four Fire Tiers represent a broader visualization of landscape/population wildfire risk.
- Operational Tiers: An interim output that interprets and further aggregates the more granular Fire Tiers into three larger risk polygons to facilitate the operationalizing of wildfire risk mitigations.
- Wildfire Operations Map: The product of landscape/population fire risk informed by broad utility infrastructure and corresponding asset locations to create three contiguous risk tier

[93] *Id.*

[94] *Id.*

polygons that can be more easily interpreted for operational and mitigation prioritization decision-making purposes.

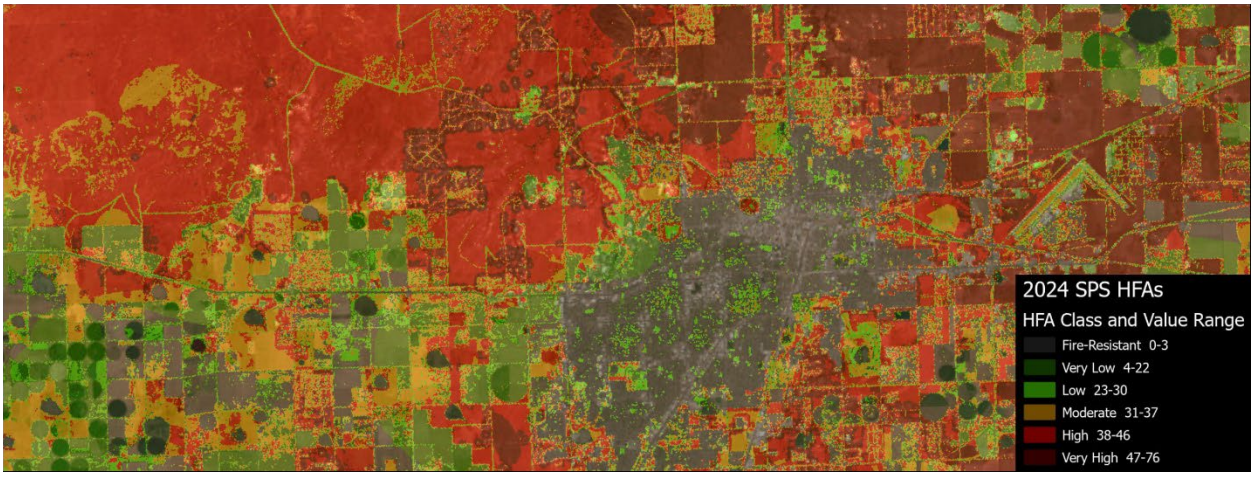
The basis for all four analyses and map outputs is similar, however the HFAs and Fire Tiers provide more granular insight into the relative hazards across the landscape whereas the Operational Tiers and the Wildfire Operations Map meld the information into generally larger polygons more appropriate for prioritizing and operationalizing mitigation strategies. SPS's Wildfire Risk Map outputs are scheduled to be updated approximately every three years to continuously improve the wildfire risk map outputs as new data become available and SPS's wildfire risk mitigation efforts evolve and mature over time.

Below are summaries of each wildfire risk map output:

Hazardous Fire Areas

HFAs are a foundational dataset that give SPS the ability to see wildfire risk more granularly. The WRO baseline data is used to produce the HFAs, which are then weighted and scored or valued locally for where population and SPS facilities are located. HFA values are then developed, with six classes ranging from fire resistant to very high risk. Figure 22 below shows a detailed image of the HFAs localized to a developed area within SPS's Texas service area.

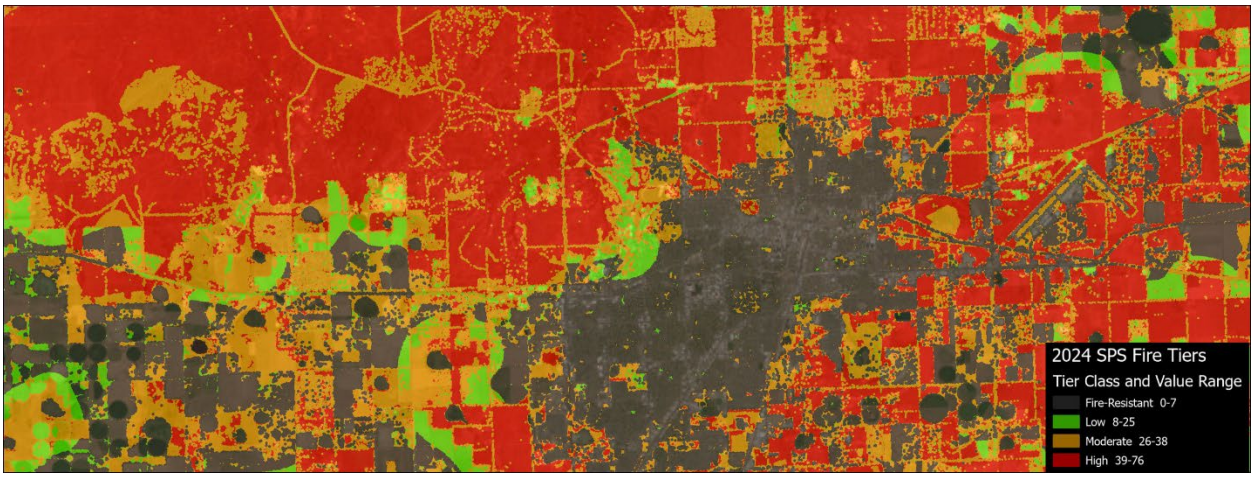
Figure 22 –Localized Detailed Image of HFAs in SPS's Texas Service Area



Fire Tiers

The Fire Tiers are aggregated from the HFAs using broader wildfire risk value ranges per Tier than the individual HFAs to develop a geospatial wildfire risk visualization variant. The six HFAs were aggregated into four Fire Tier levels or adjective classes: fire-resistant, low, moderate, and high. Fire-resistant areas include areas with significant human development and landscapes resistant to fires (e.g., bodies or water and waterways, dense urban areas covered by buildings and surfaces covered in asphalt, and irrigated fields). Low areas include areas of human development that reduce the likelihood of a large, destructive wildfire. In general, urban and semi-urban areas can be classified as low. However, a catastrophic wildfire can still occur in areas designated as low, depending on fire danger and fire weather conditions severity and fire suppression resource availability. Moderate areas are areas where a wildfire may cause significant damage to human infrastructure due to fuel continuity or terrain. High areas are areas in which fuel continuity and population density are such that wildfire is more likely to become a destructive or catastrophic event. Figure 23 below shows a detailed image of the Fire Tiers localized to a developed area within SPS's Texas service territory.

Figure 23 –Localized Detailed Image of Fire Tiers in SPS's Texas Service Area



Operational Tiers

The Operational Tiers were developed as an interim and preliminary step to help "operationalize" the Wildfire Risk Map by modifying and reshaping the more granular geospatial HFAs and Fire Tiers into larger polygons. Essentially, the Operational Tiers are interpreted from

the HFAs and Fire Tiers to create fewer, more contiguous tier polygons in order to facilitate the development of the Wildfire Operations Map. Building the Operational Tiers involves modifying or "pulling" and "pushing" the Fire Tier boundaries to encompass similarly dense Fire Tier classifications into fewer homogenous landscape/population fire risk polygons and aggregates the four Fire Tiers into three Operational Tiers (Low – Tier 1, Moderate – Tier 2, and High – Tier 3). In general, this effort yields a visual, geospatial interpretation of the landscape / population wildfire risk as represented by the HFAs and Fire Tiers; it does not account for the centerline locations of SPS assets.

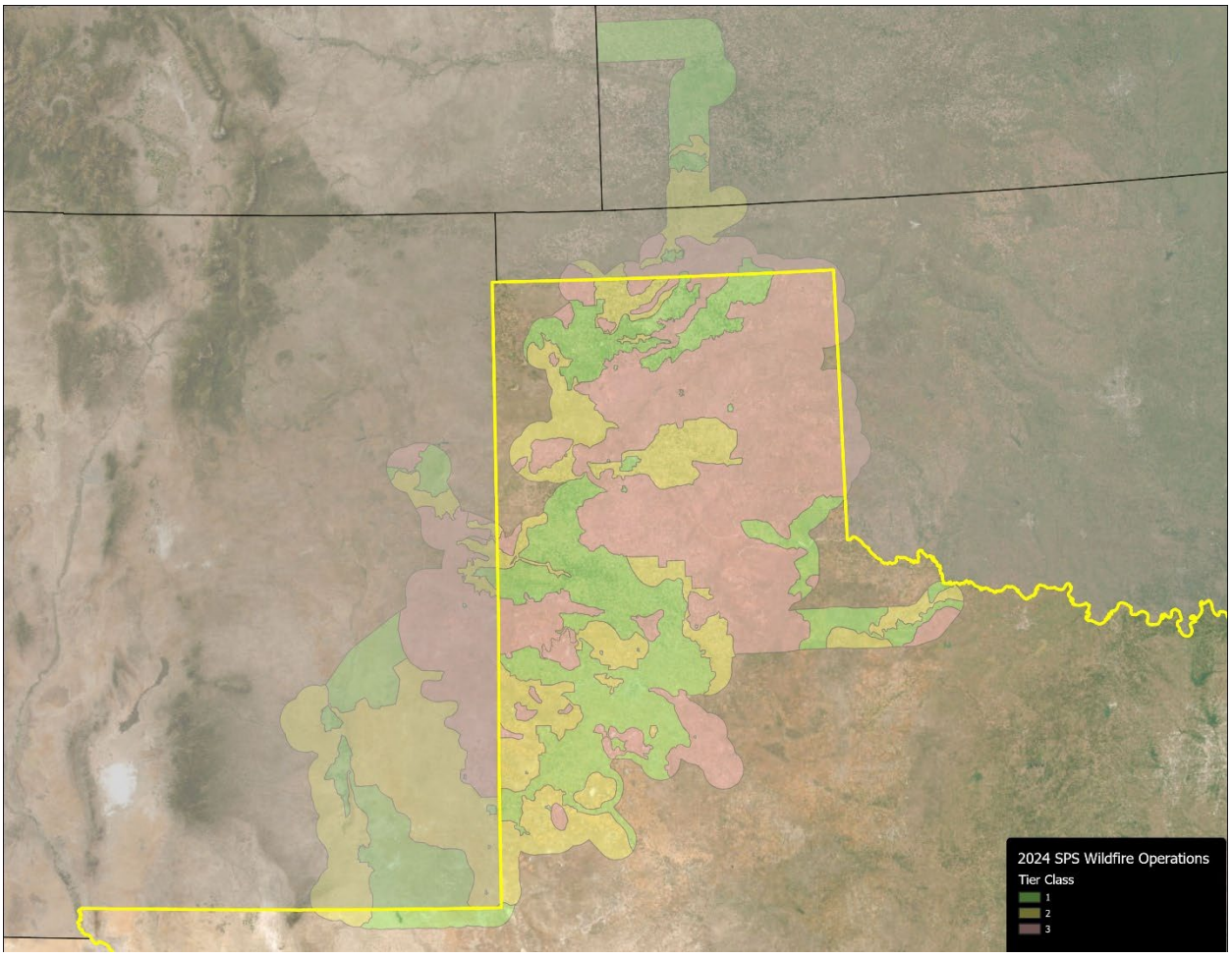
Wildfire Operations Map

Developing the Wildfire Operations Map involved leveraging the local knowledge of SPS subject matter experts regarding operations, assets, and field conditions to adjust the boundaries of the Operational Tiers by logically aggregating areas and grouping or categorizing SPS circuits and assets into similar risk tier classifications. In general, these contiguous boundaries can be more easily interpreted for operational and prioritization decision-making purposes. Recognizing that individual circuits can traverse wildlands and developed areas with varying wildfire-risk characteristics and Tier classifications, homogenous areas of risk categorization were defined for circuits and facilities to be visually assigned and grouped to provide consistency for operational decisions. For example, if a distribution circuit is located in a region predominately categorized as "High" fire risk with fewer line miles traversing areas of "Moderate" and "Low" risk, the entire risk area surrounding the distribution feeder may be adjusted to the "High" risk tier. From an operational perspective, activities undertaken by utility personnel for that circuit, or the surrounding area would be treated as if it were "High" risk, regardless of the designation of each individual hexagon or pixel in the original HFAs or Fire Tier-based maps.

The Wildfire Operations Map is a map of geospatially grouped facilities and circuits that references and interprets localized wildfire risk provided by the HFAs, aggregated Fire Tiers, and preliminary Operational Tiers analyses. The Wildfire Operations Map is intended to enhance operational efficiencies and facilitate risk-based operational decisions by asset and/or circuit (e.g., system operations, field operations, etc.). This can allow for more focused and efficient utilization of risk mitigation resources and consistent implementation of wildfire mitigation practices across

the SPS service area. SPS is prioritizing resource allocations and implementation of its Wildfire Situational Awareness and Wildfire Operations Mitigations activities in the higher fire risk areas demarcated as Tier 2 and Tier 3 in the Wildfire Operations Map. Figure 24 below is an image of the regional Wildfire Operations Map and Tiers with emphasis on SPS's Texas service territory.

Figure 24 – SPS Wildfire Operations Map and Tiers



2.1.b Description of Enhanced Meteorology Capabilities Activity

Weather stations gather real-time data essential for weather forecasts and the validation of weather models. These stations monitor various weather conditions, including temperature, relative humidity, wind speed and direction, solar radiation, and fuel moisture content. This information helps identify areas at high risk for wildfires, triggers early warnings, and informs

decisions regarding operational mitigations and targeted inspections. By establishing a network of weather stations, utility companies can gain a more detailed understanding of local weather patterns and conditions and thereby take more informed proactive measures to prevent wildfires. Weather stations strategically installed relative to the location of SPS assets can provide invaluable data for mitigating wildfire risks.

SPS plans to install a total of 110 weather stations in areas of heightened wildfire risk (Tiers 2 and 3). These automated weather stations can be deployed in remote locations and installed directly onto utility poles, allowing for more precise and site-specific weather data collection than is typically obtained through less granular government or third-party monitoring networks. Annual maintenance and equipment repairs are part of an ongoing process to ensure optimal data quality, reliability, and sustainability.

The new devices must comply with SPS's installation standards and clearances, and their locations will depend on the distribution and transmission circuits, as well as the type of assets involved. Upfront planning will be necessary to complete the installation design. This may include geospatial design as well as material and labor considerations (such as new poles, permits, and labor).

Once installed, SPS will retrieve the weather data it collects from an external cloud platform and transfer it to an internal IT database for daily analysis and reporting. This data will guide proactive operational decision making and thereby help ensure the safety and reliability of our operations. Additionally, SPS will use the data for ongoing climate studies, enhancing its understanding of long-term weather patterns that impact SPS asset performance. This knowledge will support future investments in more sustainable approaches to system hardening, public safety, wildfire prevention, and operational mitigations.

2.1.c Description of Weather and Fire Science Modeling Activity

Advanced modeling tools like the ones SPS is proposing to implement through this SRP—Fire Sight, Risk Associated with Value Exposure ("RAVE") and Risk Associated with Ignition Location ("RAIL")—have become essential in navigating the complexities posed by wildfires.

These tools provide comprehensive insights into wildfire risks, enabling utilities to implement effective preventive measures and enhance resilience against wildfires.

Fire Sight is a sophisticated wildfire risk management tool that leverages historical weather and fire science modeling to identify risks across landscapes. It evaluates various factors, including weather, topography, fuels, historical wildfire occurrence, and utility outage data to pinpoint areas where preventive actions can have the most significant impact. By analyzing this data, Fire Sight allows electric utilities to design mitigation projects to optimize mitigation effectiveness for asset hardening and vegetation management by prioritizing those assets with the highest expected risk. This tool enhances the ability to visualize and understand wildfire risks effectively, supporting operational decisions aimed at reducing risks to customers and communities.

RAVE focuses on evaluating the potential consequences of wildfires by assessing location-specific risks. This tool comprehensively analyzes the impact of wildfires on various values-at-risk, such as population, buildings, and critical facilities. By leveraging an extensive historical data repository, RAVE enables machine learning models to predict possible building loss and other consequences. This powerful tool enhances the ability to visualize and understand risks effectively, supporting utilities in making informed decisions to mitigate wildfire risks and protect communities.

RAIL is designed to characterize wildfire risk associated with specific ignition locations, such as electrical utility network assets. Unlike static risk assessments, RAIL assigns potential impacts to the ignition location, identifying which assets have the greatest risk of causing a wildfire. The analysis considers three main components: the probability of ignition for the asset, the fire spread potential of wildfires starting at the asset ignition location, and the consequence of the values-at-risk impacted by the fire spread. By combining these components, RAIL provides risk scores for specific assets, enabling utilities to prioritize mitigation efforts and reduce wildfire risks effectively.

The integration of Fire Sight, RAVE, and RAIL data into wildfire risk management strategies offers significant value and benefits. These tools provide comprehensive insights into wildfire risks, enabling utilities to implement effective preventive measures and enhance resilience against wildfires.

2.1.d Description of Artificial Intelligence Cameras ("AI Cameras") Activity

AI Cameras provide 24/7 real-time wildfire detection and alerts, featuring optical zoom capabilities that enhance detection and evaluation. AI Cameras are strategically mounted in locations with overlapping viewsheds, with the primary purpose of situational awareness for early wildfire detection. Each identified location is equipped with two physical cameras that rotate to detect smoke. These high-resolution cameras gather data that is verified and forwarded by a human operator. This system delivers real-time information and fire detections, which are shared with SPS and first responders. The AI Cameras have demonstrated exceptional accuracy and speed in detecting fires, allowing for quicker fire suppression responses and reducing the impact of wildfires. SPS plans to install a total of 68 cameras in Tier 2 and Tier 3 wildfire risk areas. SPS is partnering with Pano AI for implementation of the AI Cameras. Attached as Attachment C is a white paper from Pano AI, titled "Pano AI's Impact on Wildfire Mitigation," providing additional context for this activity.

2.2 Description of Wildfire Physical Mitigations Program

The Wildfire Physical Mitigation program activities aim to help SPS prevent wildfire and protect its service area. The activities help mitigate (1) potential utility ignition sources and (2) physical wildfire risks to equipment used in its service area. The Physical Mitigation programs under the Wildfire measure include (1) Defensible Space Around Poles ("DSAP"), (2) wood substation conversion, and (3) transmission wildfire detailed inspection.

2.2.a Description of DSAP Activity

The DSAP program focuses on managing and removing vegetation that could act as fuel for wildfires near transmission and distribution assets in these areas, free of brush, limbs, foliage, and grasses. DSAP is specifically tailored to the type of asset and its related equipment. As part of the program, any existing wood debris not generated by SPS may be removed, whenever practical, following discussions with landowners or land management agencies. The DSAP program plays a crucial role in minimizing the risk of wildfires by establishing safe zones around power lines and their associated equipment. By doing so, it significantly reduces the chances of ignition from wildlife encounters, severe storms, and extreme weather conditions.

For distribution poles, the DSAP zone includes a 10-foot radius and an 8-foot vertical area around the pole. In the case of transmission lines, DSAP entails clearing a 50-foot radius around transmission structures, or the full width of the easement or Right of Way ("ROW"), whichever is smaller. As part of both distribution and transmission DSAP activities, herbicide treatments will likely be applied annually to prevent the regrowth of vegetation.

To ensure transparency and foster positive relationships with the community, SPS will implement a comprehensive customer outreach strategy. This strategy includes informing property owners about the DSAP program through various channels. Property owners will receive detailed information about what to expect during the DSAP activities, including the specific areas involved and the potential impacts on their property. By collaborating closely with property owners and external stakeholders, SPS aims to build trust and ensure that the DSAP program is conducted in a manner that is respectful of community needs and concerns. Regular updates will be provided throughout the program to keep everyone informed about progress and any changes that may occur.

2.2.b Description of Wood Substation Conversion Activity

SPS will remove wood substations located in the Wildfire Operations Map Tiers 2 and 3 with plans to implement distribution feeder level voltage conversions or step-downs at each site. There are four wood substations in Tiers 2 and 3 in Texas that are owned and operated by SPS. SPS will address all four of these sites, as follows:

- Follett (two step-downs)
- Higgins (two step-downs)
- Kerrick (conversion)
- Magnolia (step-down)

Most of the electric equipment and conductor within substations are mounted onto structural members. In modern substations, these structural members are typically made of steel. In the past, treated wood was sometimes used for the substation structure, especially for smaller distribution substations. The wood substations on SPS's system are nearing the end of their expected lifespan. Removing these aging substations provides the opportunity to modernize the

system. It also improves resiliency by removing wood structures, which are more susceptible to damage from resiliency-type events such as fires and high winds.

2.2.c Description of Transmission Wildfire Detailed Inspection Activity

This wildfire-based program will primarily involve performing detailed visual inspections (i.e., ground patrols) of transmission lines and poles. Lines in Tier 3 of the Wildfire Operations Map will be patrolled annually. Lines in Tier 2 will be patrolled every two years. Lines in Tier 1 will be inspected on a four-year cycle and costs for those patrols are not included in this filing.

These inspections will be completed by Qualified Electrical Worker ("QEW") equipped with high-power binoculars and other tools, approaching transmission assets (e.g., structures) by driving or walking and then inspecting them from a short distance away. SPS currently conducts routine high-speed helicopter aerial patrols for rapid transmission line and structure inspections, but these inspections can lack the granularity and detail required to identify certain smaller component defects. Therefore, there is a need to conduct detailed visual inspections more frequently in higher-risk wildfire areas. While the primary method of inspection in this program will be ground patrols, SPS may incorporate additional inspection techniques, such as high-resolution imagery assessments and detailed helicopter-aided aerial inspections in instances where ground inspection may be difficult to perform due to challenging access or to enable more comprehensive evaluation of asset conditions. The benefits of these patrols are increased situational and operational awareness of system and asset conditions. Factors such as exposure to weather and storms, decay, corrosion and other age-related deterioration, and impacts from equipment (e.g., farm equipment) can affect the condition of the assets, and detailed patrols allow for identification and classification of defects on the transmission system ahead of failures. The defects identified through the inspection program are addressed through transmission asset health programs such as End of Life Replacement, Major Line Rebuild, and Major Line Refurbishment.

3. Evidence of Effectiveness and Expected Benefits

The Resiliency Rule requires an SRP to "include evidence of the effectiveness of the measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed

by the identified resiliency event."[95] Evidence that is quantitative, performance-based, or provided by an independent entity with relevant experience is afforded greater weight.[96] Further, the SRP must "explain the expected benefits of the resiliency measures including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers, and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations."[97]

EDM assisted SPS in developing effective programs to maximize wildfire risk mitigation. EDM is an independent consultant with expertise in wildfire mitigation program development. SPS selected the programs in the Wildfire Mitigation measure based on SPS's operational experience in the Texas Panhandle and Plains regions, EDM's wildfire risk mitigation expertise, and industry-leading practices, to ensure the Wildfire Mitigation measure is effective in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by wildfire.

The expected benefits of this measure include reducing the frequency and duration of customer outages caused by wildfires, reducing restoration costs, and improving overall service reliability for customers. The Situational Awareness program will reduce the frequency and duration of outages and reduce restoration costs by giving SPS greater visibility into the state of the system and potential wildfire conditions, allowing SPS to more quickly activate EPSS, coordinate with first responders, and ready personnel and equipment to respond if a wildfire ignites. The Physical Mitigation program will reduce the frequency of outages and restoration costs by proactively protecting, hardening, and inspecting SPS facilities in wildfire zones Tier 2 and 3. As EDM concluded, the programs SPS is proposing are consistent with other leading utilities wildfire mitigation programs, are dynamic and evolving and are, therefore, consistent with good utility practice.

[95] 16 TAC § 25.62(c)(2)(A)(ii).

[96] 16 TAC § 25.62(c)(2)(A)(iii).

[97] *Id.*

4. Proposed Implementation of Program Implementation

The Resiliency Rule requires an SRP to include "implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments."[98]

Both the Situational Awareness and Physical Mitigations programs have an estimated implementation timeline beginning mid-2025, through 2028, consistent with the implementation timeline of the SRP. Table 17 includes the estimated implementation budget for these programs.

Table 17 – Wildfire Mitigation Estimated Implementation and Budget

Program	Execution Timeline	Estimated capital spend	Estimated O&M spend	Total Estimated Spend
Situational Awareness	Mid-2025 through 2028	$16.8M	$2.2M	$19.0 M
Physical Mitigation	Mid-2025 through 2028	$2.7M00,000.00	$13.6M	$16.3M

5. Metrics for Evaluating Effectiveness

The Resiliency Rule requires that "[e]ach measure in the resiliency plan must include a proposed metric or criteria for evaluating the effectiveness of that measure in preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the resiliency event it is designed to address."[99]

The metrics SPS proposes to evaluate the effectiveness of the Wildfire Mitigation Measure include calculating asset fire susceptivity factors based on fire simulations and an annual evaluation of asset failure and outages based on the windspeed detected at the nearest weather

[98] 16 TAC § 25.62(c)(2)(E).

[99] 16 TAC § 25.62(c)(2)(C).

station to determine asset fragility curves. Please see Section V of this Plan for details on the evaluation metrics.

6. Reasonable Alternatives Reviewed

The Resiliency Rule requires that an SRP "explain the selection of each measure over any reasonable and readily-identifiable alternatives."[100]

There are a few alternatives that would address wildfire mitigation in SPS's service area, including continuation of an already existing inspection program, replacement of certain substations, and a new public private data collaboration. SPS considered these alternatives, and ultimately landed on the above programs, as EDM confirmed that in their experience the above programs are consistent with other leading utilities' wildfire mitigation programs and what state regulators would expect to see in a utility's wildfire mitigation planning efforts.

The Wildfire Annual Visual Inspections would be a continuation of a four-year detailed inspection cycle without an increase in cadence. The wood substation conversion program contemplated replacement of all wood structure with steel structures or substation skids. This was not the chosen solution because the replacement would cost 600 to 1900 percent more and substation skid would cost 300 to 1100 percent more than the step-down and conversion solutions. Additionally, these sites are distribution fed, and a substation asset is non-standard for such sites in SPS. Finally, while collaboration between public and private companies could enhance the availability of data related to wildfire situational awareness, the data may be too broad to apply specifically to the identified high-risk wildfire areas. Additionally, the frequency and accuracy of the data may not allow SPS to make timely operational decisions.

7. Measure Distinction from Existing Programs

Pursuant to the Resiliency Rule, if a utility's resiliency plan measures are similar to programs and measures the utility is already implementing, the plan "must distinguish the

[100] 16 TAC § 25.62(c)(2)(A)(v).

measures in the resiliency plan from these programs and measures and, if appropriate, explain how the related items work in conjunction with one another."[101]

While some of the programs under this measure are similar to SPS's existing programs for wildfire mitigation, the programs described above are on a quicker cadence (i.e., transmission visual inspections, DSAP, etc.) in order to enable SPS to more quickly and efficiently mitigate risks.

SPS, moreover, is able to derive significant benefits by drawing on the experiences of SPS's affiliate, Public Service Company of Colorado ("PSCo"). In Colorado, PSCo has a robust wildfire mitigation program which encompasses many of the same programs that SPS has included in this SRP, including but not limited to enhanced meteorology capabilities, weather station deployment, weather and fire science modeling, enhanced vegetation management, and enhanced powerline safety settings. SPS is able to leverage in Texas the experience of Xcel Energy employees who have been engaged in the Colorado programs.

8. Additional Information Required by the Resiliency Rule

The Resiliency Rule requires an SRP state whether a measure (1) "is a coordinated effort with federal, state, or local government programs or may benefit from any federal, state, or local government funding opportunity"[102] or if the measure (2) "may require a transmission system outage to implement."[103]

The Wildfire Mitigation measure is not a coordinated effort with any federal, state, or local government program. However, as a part of the Bipartisan Infrastructure Law, the U.S. Department of Energy's Grid Deployment Office is administering a $10.5 billion Grid Resilience and Innovation Partnerships ("GRIP") program to improve the resilience of utility infrastructure against growing threats of extreme weather and climate change. SPS was awarded $7.3 million to

[101] 16 TAC § 25.62(c)(2)(D).

[102] 16 TAC § 25.62(c)(2)(A)(iv).

[103] 16 TAC § 25.62(c)(2)(A)(vi).

use for Weather and Fire Science modeling software, and if the SRP is approved, SPS is proposing to use those funds to offset the costs to its Texas customers.

Additionally, the Wildfire Mitigation measure should not require any transmission outages. If, however, an outage is required, SPS commits to coordinate the outage with Southwest Power Pool.

V. PROPOSED METRICS FOR EVALUATING EFFECTIVENESS

The Resiliency Rule requires that "[e]ach measure in the resiliency plan must include a proposed metric or criteria for evaluating the effectiveness of that measure."[104] SPS proposes a suite of metrics that cover the various measures in its SRP.

Consistent with the Resiliency Rule, SPS developed its proposed metrics to provide a quantitative assessment of the effectiveness of the resiliency measures proposed in this SRP. The metrics are intended to be considered together as a portfolio to illustrate the resiliency of the SPS transmission and distribution systems. SPS proposes to report on its SRP annually, consistent with the Resiliency Rule, through the metrics described below.

Several measures have multiple associated metrics. And several metrics are useful for considering the efficacy of multiple measures.

SPS's proposal includes metrics it has not previously tracked or used, and SPS is including innovative metrics, particularly associated with the Wildfire Mitigation measure. Accordingly, it will take time to develop reliable rolling averages to accurately assess improvements to resiliency based on implementation of this SRP. SPS expects to begin to collect new and more accurate data over the course of the planned implementation period of 2025 through 2028, particularly given that the SRP itself includes new technology and communication build-out. After implementation of this inaugural SRP is underway, SPS may discover new and additional points of analysis or data tracking, which it can develop for consideration in future plan submittals.

[104] 16 TAC § 25.62(c)(2)(C).

Table 18 –Metrics for Evaluating Effectiveness					
Metric	**Distribution Overhead Hardening**	**Distribution System Protection Modernization**	**Communication Modernization**	**Operational Flexibility**	**Wildfire Mitigation**
Underperforming Area Count	X	X	X		
Rolling 10-Year Average SAIDI	X	X	X	X	
Storm Restoration Duration	X	X	X		
Average Hardened Protection Zone (AHPZ) CI vs Average Protection Zone (APZ) CI Comparison by County (Hardened Only)	X				
AHPZ CI Percentage Improvement	X				
RAN Tower Completion			X		
End Device Connectivity			X		
Units Completed in DSAP					X
Transmission Inspections					X

Underperforming Area Count

Identifies the number of underperforming areas across the SPS System as categorized by 16 TAC §25.52. "Underperforming Areas" include distribution feeders for which the System Average Interruption Duration Index ("SAIDI") or System Average Interruption Frequency Index ("SAIFI") exceeds the system average by more than 300 percent for two or more consecutive years. This metric applies to all resiliency measures except Wildfire Mitigation.

Rolling 10-Year Average SAIDI

Calculates the average duration of all outage events over the last 10 years, normalized for customer counts. This metric applies to the Distribution System Resilience and Distribution System Protection Modernization measures. This metric applies to all resiliency measures except Wildfire Mitigation. This metric is only recommended to be considered after the first several years of resiliency investment, as it takes time to realize the impact of resiliency measures.

$$Rolling\ 10\ Year\ Average\ SAIDI = \frac{\sum_{i-1}^{10} Total\ SAIDI_i}{10}$$

Storm Restoration Duration

Calculates an average storm restoration duration for Major Event Days with more than 2.5 beta, as defined by IEEE 1366. Each year, a new average restoration duration is calculated and compared with the average durations from the previous three years. This metric applies to all resiliency measures except Wildfire Mitigation. This metric will require the impact of the resiliency measures to accumulate over the first several years of the investment before it is considered for evaluating effectiveness.

$$Storm\ Restoration\ Duration = \frac{\sum_{i=1}^{n}(Restoration\ Duration)_i}{Total\ Number\ of\ Major\ Event\ Days}$$

Average Hardened Protection Zone (AHPZ) CI vs Average Protection Zone (APZ) CI Comparison by County (Hardened Only)

Average Hardened Protection Zone ("AHPZ") CI vs. Average Protection Zone ("APZ") CI Comparison by County (Hardened Only) – Compares hardened protection zones with non-hardened protection zones. This metric applies to the Distribution System Resiliency measures.

$$AHPZ\ CI = \frac{\sum_{i=1}^{n} Total\ CI_i}{Hardened\ Protection\ Zone\ Miles}$$

$$APZ\ CI = \frac{\sum_{i=1}^{n} Total\ CI_i}{Non\ Hardened\ Protection\ Zone\ Miles}$$

AHPZ CI Percentage Improvement

Estimates the performance improvement between non-hardened protection zones and hardened protection zones. This metric includes all interruptions and applies to the Distribution System Resiliency measures.

$$AHPZ\ CI\ \%\ Improvement = \frac{AHPZ\ CI\ (Hardened) - APZ\ CI(Non\ Hardened)}{APZ\ CI\ (Non\ Hardened)}$$

RAN Tower Completion

SPS will report cellular tower construction completion, testing, and in-servicing as compared to the SRP.

End Device Connectivity

SPS will report connectivity of end devices to PLTE cellular towers, including acceptance from the business unit on end-to-end testing validation in accordance with the Plan.

Units Completed in DSAP

SPS will calculate and report the number of units identified and completed in Tiers 2 and 3 for DSAP compared to the Plan.

Transmission Inspections

Detailed inspections executed in Tier 2 and 3 wildfire areas, with associated number of emergency and high-priority defects identified and remediated.

VI. CONCLUSION

The Commission's approval of this SRP will significantly enhance SPS's efforts to build a more resilient electric system. SPS's SRP has been developed consistent with the requirements of the Resiliency Rule and includes measures and investments designed to collectively mitigate the impacts of risks posed to SPS's System from a wide range of resiliency events. SPS's Plan should be approved as proposed, as it will benefit SPS customers through reduced frequency of power outages and outage times; cost savings from decreased storm recovery costs and expensive emergency repairs; a hardened infrastructure and equipment to withstand weather events and other threats; improved overall safety, reliability, and system stability; a more modern and flexible system; and specific investments addressing wildfire risk and upgrading communication capabilities for protection, response and recovery.

1898 & CO.
PART OF BURNS McDONNELL

SPS SYSTEM RESILIENCY INVESTMENT STUDY:

A QUANTITATIVE ANALYSIS AND ASSESSMENT OF POTENTIAL RESILIENCY MEASURES ON THE SPS SYSTEM.

December 18, 2024

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TABLE OF ACRONYMS

Acronym	Term/Phrase/Name
ANL	Argonne National Laboratory
BCR	Benefit-Cost Ratio
C&I	Commercial & Industrial
CI	Customers Interrupted
CMI	Customer Minutes Interrupted
CIS	Customer Information System
DOE	Department of Energy
GIS	Geographic Information System
ICE	Interruption Cost Estimator
MED	Major Event Day
NARUC	National Association of Regulatory Utility Commissioners
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory
PUCT	Public Utility Commission of Texas
ROW	Right-of-Way
SPS	Southwestern Public Service Company
SRP	System Resiliency Plan
TAC	Tex. Admin. Code
T&D	Transmission and Distribution

1.0 Executive Summary

Southwestern Public Service Company (SPS) engaged 1898 & Co., the advisory and technology consulting arm of Burns & McDonnell, to assist with the identification, quantitative analysis, and benefit-cost assessment of investments for potential inclusion in SPS's System Resiliency Plan (SRP). 1898 & Co. used a resilience and risk-based planning approach to identify and prioritize distribution system resiliency investments utilizing an Integrated Resilience & Risk Investment Model developed by 1898 & Co. The resilience and risk-based planning approach aligns with the requirements of Public Utility Commission of Texas Substantive Rule 16 Tex. Admin. Code (TAC) § 25.62, herein referred to as the "Resiliency Rule."

1898 & Co.'s analysis includes only those customers and assets located in Texas. Any reference in this document to the SPS system, assets, or customers only includes those in Texas, unless otherwise stated.

1898 & Co.'s key objectives for the Integrated Resilience & Risk Investment Model are to:

1. Quantify the resiliency improvement expected for individual resiliency investment activities, programs, and measures, specifically estimating the decrease in the duration and frequency of customer outages and reduction in outage-restoration costs;
2. Demonstrate the expected improvement in the number and duration of customer outages for certain measures within SPS's SRP; and
3. Identify investments with the highest quantified resilience and risk benefit per dollar invested into the system.

1898 & Co.'s Integrated Resilience & Risk Investment Model employs a data-driven decision-making methodology utilizing sophisticated algorithms to calculate the resilience benefit of investments by identifying the expected range of reduced duration and frequency of customer outages, measured as Customer Minutes Interrupted (CMI), and reduced outage restoration costs. Resilience-based prioritization facilitates the identification of investments that provide the most

benefit to SPS's customers. Prioritizing and optimizing investments in the electric delivery system helps provide confidence that the overall investment level is appropriate and that customers will get the most value for the level of investment.

This report outlines the methodology employed by 1898 & Co. to identify potential resiliency investments, perform the resiliency benefit-cost analysis (BCA) for resilience investment activities, and estimate the quantifiable benefits for all potential resiliency investments. This report also lays out the approach SPS and 1898 & Co. used to select specific investments for the SRP. Table 1-1 provides an overview of the structure of the SRP and which measures and programs 1898 & Co. evaluated. Certain measures and programs include wildfire-specific investment activities, which 1898 & Co. did not evaluate. These activities, and the measures not evaluated by 1898 & Co., are addressed in other parts of SPS's filing.

Table 1-1: SRP Structure & Programs Evaluated by 1898 & Co.

Measure	Measure Program	Systematic Approach Investment Activity Identification & Cost Estimating	Effectiveness and Benefits
Distribution Overhead Hardening	Distribution Circuit Hardening Rebuilds	X	X[1]
Distribution System Protection Modernization	Mainline Automated Reclosing Deployment	X	X[1]
	Lateral Reclosing Deployment	X	X
Communication Modernization	Communication Modernization		X
Operational Flexibility	Mobile Substation Equipment Procurement		
	Installation of Transmission Switches		
Wildfire Mitigation	Situational Awareness		
	Operational Mitigation		

The Distribution Overhead Hardening Measure and Distribution Circuit Hardening Rebuild Program involve hardening specific sections of distribution circuits to withstand weather-based events by adding or replacing infrastructure to meet SPS's current hardening standards. The measure also includes wildfire-specific investments to mitigate wildfire risks. As directed by SPS, 1898 & Co. estimated scoping activities with these investments. The Distribution System Protection Modernization Measure includes investment in smart and connected protection devices to minimize the impact of disruptive events. The measure also includes wildfire-specific investments to mitigate wildfire risks. As directed by SPS, 1898 & Co. estimated scoping activities with these investments. The Communication Modernization Measure includes investments to deploy a private communication network to enable device

[1] Excludes any evaluation of the wildfire-specific investment activities that are a part of this program.

communication across the SPS system. This measure is needed to fully realize the benefits of the Distribution System Protection Modernization Measure.

1.1 Resiliency Events and SPS's System

16 TAC § 25.62(c)(2)(B)
A resiliency plan must define, identify, and describe each type of resiliency event and any associated resiliency-related risks the plan is designed to prevent, withstand, mitigate, or more promptly recover from.

1.1.1 Weather-Based Events

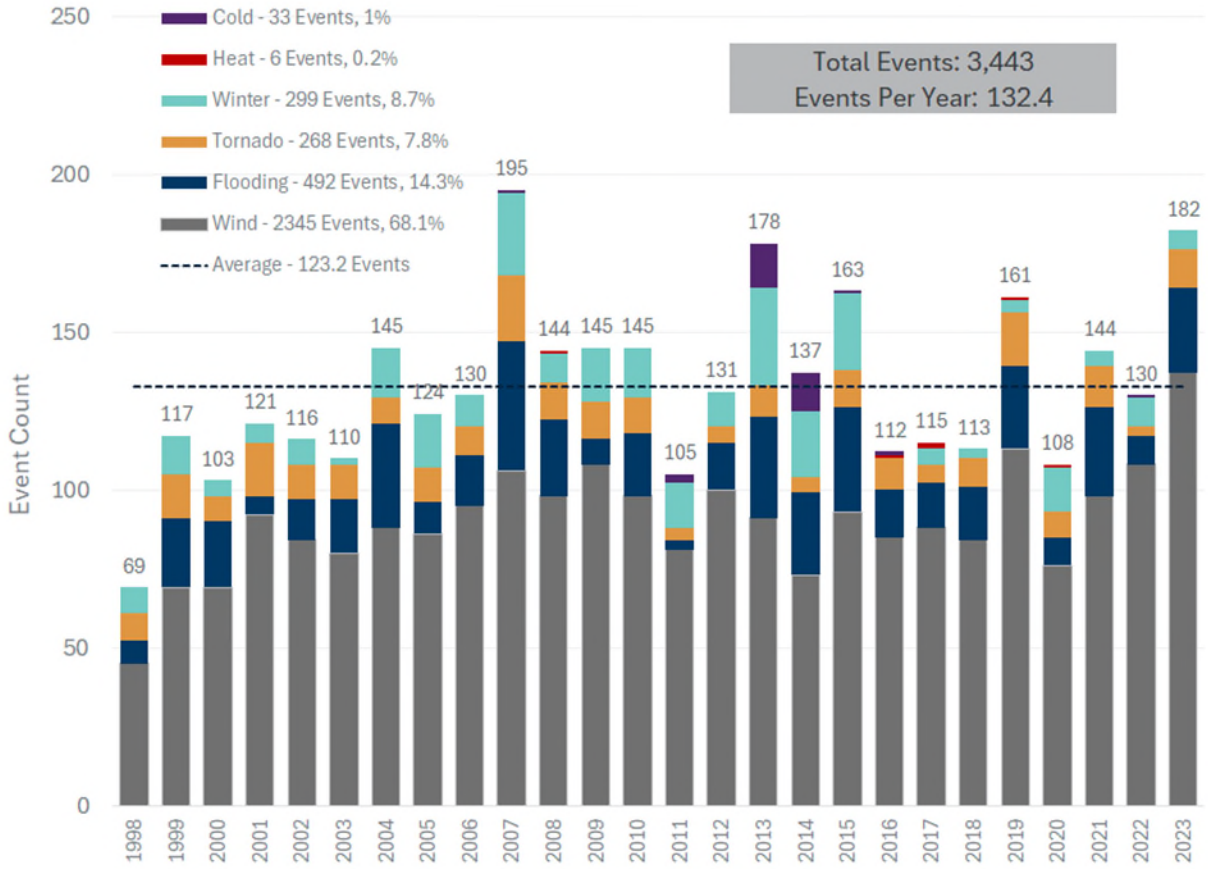
1898 & Co. used weather-based event data from the National Oceanic and Atmospheric Administration (NOAA) and SPS's outage management system (OMS) to understand the frequency and impacts of weather-based resiliency events to SPS's customers. The database includes the following types of NOAA-defined weather-based resiliency events for SPS's service area:

Extreme Weather	
Wind	11. Sleet
1. Thunderstorm Wind	12. Winter Storm
2. Lightning	13. Heavy Snow
3. Hail-Wind	14. Ice Storm
4. High Wind	15. Hail-Winter
5. Strong Wind	16. Blizzard
Flood	**Heat**
6. Flood	17. Heat
7. Heavy Rain	18. Excessive Heat
8. Flash Flood	**Drought**
Tornado	19. Drought
9. Tornado	**Cold**
Winter	20. Cold/Wind Chill
10. Winter Weather	21. Extreme Cold/Wind Chill

A total of 3,443 weather-based resiliency events impacted the SPS service area from

1998 to 2023, averaging 132.4 events per year. Figure 1-1 shows the resiliency event count for the SPS service area beginning in 1998, broken down by event type. This analysis excluded drought events since their durations are so long and the correlations between drought events and OMS outages is challenging to identify with any certainty. Many of the other resiliency events, specifically heat, that occur during these long-duration drought events are included in the evaluation. Wildfire events were also excluded from the analysis, as they are not part of 1898 & Co.'s analysis. The figure shows that a wide range of events occur from year to year with 1998 having a low of 69 events while 2007 had 195, almost triple the number of events in 1998. Wind-type events account for the highest percentage of events to impact the SPS service area at 68% of the total event count.

Figure 1-1: Count of Weather-Based Resiliency Events for SPS's System by Year[2]



1898 & Co. organized the SPS service area into counties and evaluated the historical weather-based resiliency events at that level to understand the locational differences of those events. This organization is described in more detail in Section 3.0. This organization of events showed the following:

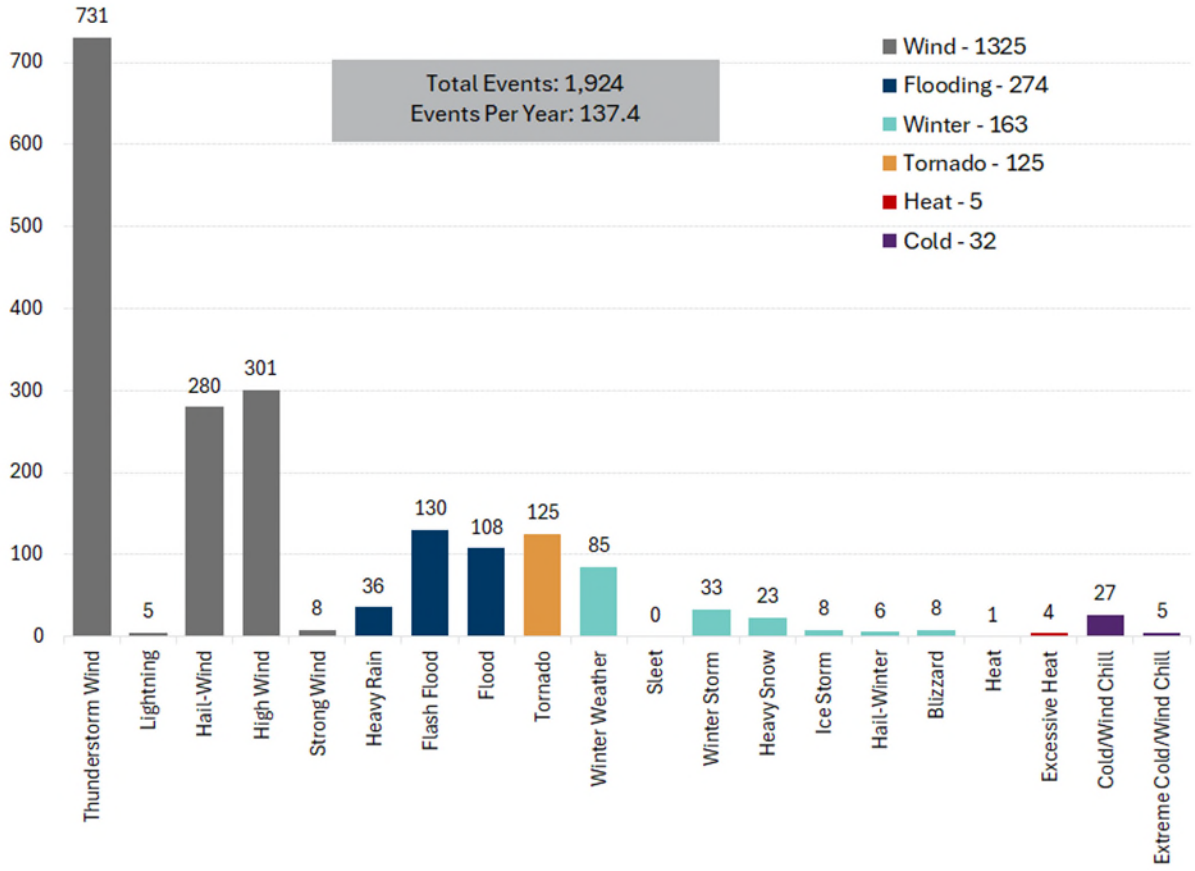
- **The number of events varies significantly** across SPS's service area.
- **The profile of resiliency-event types also varies significantly** across each county, demonstrating the challenge before SPS in building and maintaining a resilient system.

1898 & Co. performed a correlation analysis between the NOAA event data and SPS's historical outage records. As noted above this evaluation excludes wildfire and drought events. For the period of 2010 through 2023, 1898 & Co. correlated each

[2] Source: https://www.ncdc.noaa.gov/stormevents/ with analysis by 1898 & Co.

event in the NOAA data to SPS's outage records based on time stamps from both data sets. This correlation allows customer outages to be directly linked to specific resiliency events to assess how the system performed during an individual event. 1898 & Co. identified over 1,924 NOAA events where an outage was recorded in SPS's OMS. Figure 1-2 shows the event types 1898 & Co. mapped to SPS's OMS.

Figure 1-2: NOAA Events identified in SPS's Outage Records (2010-2023)[3]



Over the period of 2010 through 2023, SPS recorded outages of approximately 417.8 million CMI. 1898 & Co. mapped approximately 273.1 million CMI to one of the 1,924 NOAA events. In other words, approximately 65.4% of SPS CMI occurred during one of the resiliency events recorded by NOAA, and the remaining 34.6%, or 144.8 million CMI occurred during "blue-sky" reliability days. **This shows the significant**

[3] Source: https://www.ncdc.noaa.gov/stormevents/ and SPS's OMS with analysis by 1898 & Co.

contributions of major weather events to customer outages and the need for resilience investment to mitigate these impacts.

For the 65.4% of all CMI that occurred during a resiliency event, Figure 1-3 shows the mapped CMI for each of the event types over the 2010-2023 period. This correlation demonstrates the substantial benefit SPS customers stand to gain through resiliency investment in the SPS system.

Figure 1-3: Mapped CMI to NOAA Events[4]

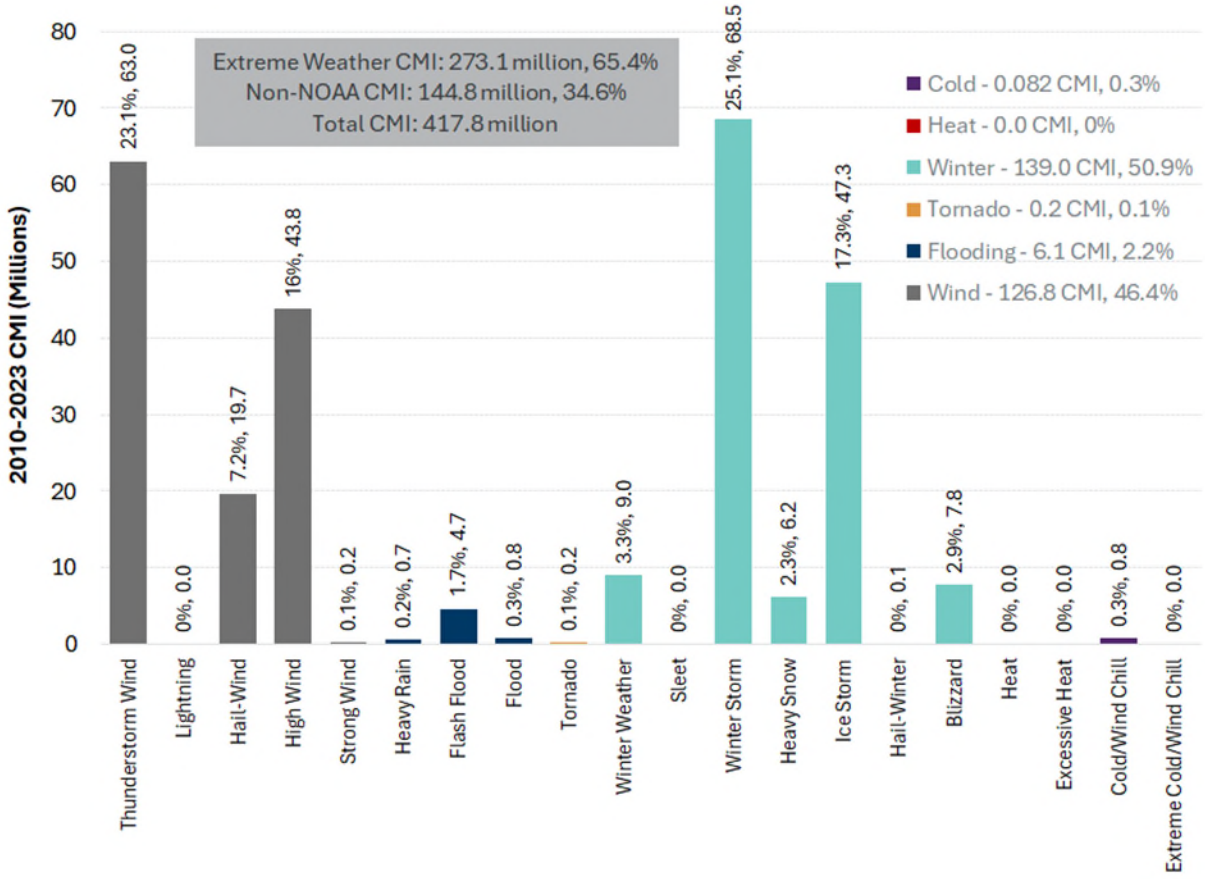
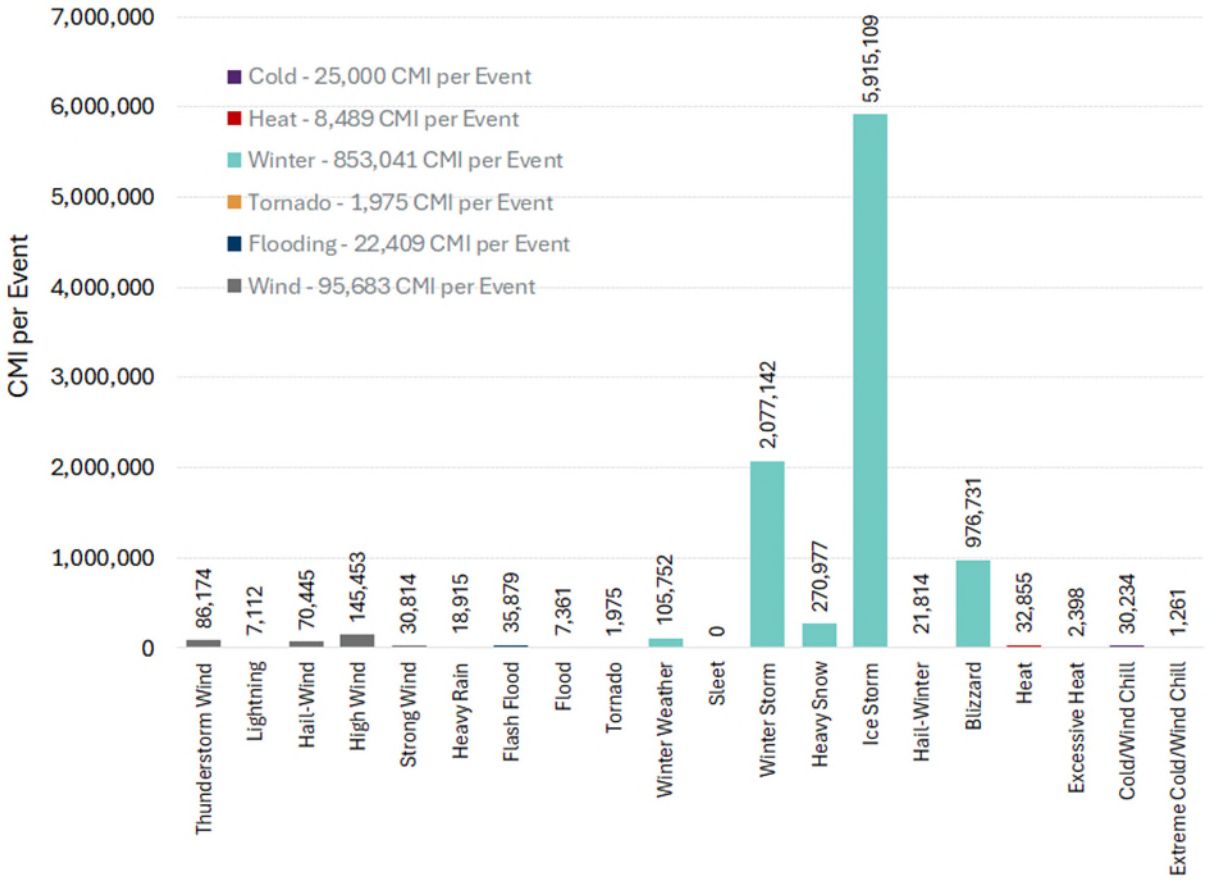


Figure 1-4 shows the historical average CMI per event for each event type. These results are derived by taking the CMI from Figure 1-3 and dividing by the number of events from Figure 1-2. These values serve as the basis to understand the consequence of individual events on the system.

[4] Source: https://www.ncdc.noaa.gov/stormevents/ and SPS's OMS with analysis by 1898 & Co.

Figure 1-4: CMI Per Event[5]



1.1.2 Event Prioritization Summary

16 TAC § 25.62(c)(2)(A)(i)
The resiliency plan must explain the electric utility's prioritization of the identified resiliency event and, if applicable, the prioritization of the particular geographic area, system, or facilities where the measure will be implemented.

Table 1-2 provides a prioritization of the resiliency events evaluated by 1898 & Co. that impacted SPS customers. Table 1-2 prioritizes the quantified event types based on their expected annual average CMI. This value is the average number of events per year, the frequency, multiplied by the CMI per event, the impact. The average number of events per year is for the 1998 to 2023 period based on the NOAA data, as

[5] Source: https://www.ncdc.noaa.gov/stormevents/ and SPS's OMS with analysis by 1898 & Co.

shown in Figure 1-1 above. The CMI per event is from Figure 1-4 above. The table also includes the relative ranking of the event frequency and impact.

Table 1-2: Prioritization of Resiliency Events

No	Event Category	Event Type	1998 - 2023 Avg Events / Year	CMI Per Event	Annual Average CMI	Event Frequency Rank	Event Impact Rank
1	Winter	Winter Storm	2.12	2,077,142	4,393,954	9	2
2	Winter	Ice Storm	0.73	5,915,109	4,322,580	12	1
3	Wind	Thunderstorm Wind	47.15	86,174	4,063,436	1	7
4	Wind	High Wind	16.27	145,453	2,366,409	3	5
5	Wind	Hail-Wind	25.46	70,445	1,793,630	2	8
6	Winter	Heavy Snow	3.04	270,977	823,354	8	4
7	Winter	Blizzard	0.54	976,731	525,932	15	3
8	Winter	Winter Weather	4.50	105,752	475,882	7	6
9	Flooding	Flash Flood	12.08	35,879	433,306	4	9
10	Flooding	Flood	5.00	7,361	36,805	6	15
11	Flooding	Heavy Rain	1.85	18,915	34,920	10	14
12	Cold	Cold/Wind Chill	1.08	30,234	32,559	11	12
13	Tornado	Tornado	10.31	1,975	20,362	5	18
14	Wind	Strong Wind	0.58	30,814	17,777	14	11
15	Winter	Hail-Winter	0.54	21,814	11,746	15	13
16	Wind	Lightning	0.73	7,112	5,197	12	16
17	Heat	Heat	0.08	32,855	2,527	19	10
18	Heat	Excessive Heat	0.15	2,398	369	18	17
19	Cold	Extreme Cold/Wind Chill	0.19	1,261	243	17	19
20	Winter	Sleet	0.04	0	0	20	20

The information in Table 1-2 is the core event data utilized within the Integrated Resilience & Risk Investment Model to estimate the quantified benefits of resilience investments across the system. This is discussed in the next section.

1.2 Resilience and Risk Based Planning Approach

16 TAC § 25.62(c)(2)(E)

A resiliency plan must be implemented using a systematic approach over a period of at least three years. The resiliency plan must explain this systematic approach and provide implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments. The resiliency plan should identify relevant cost drivers (e.g., line miles, frequency of inspections, frequency of trim cycles, etc.) that would affect the estimates.

1898 & Co. utilized a resilience and risk-based planning approach to identify, prioritize, and perform benefit modeling to support the development of the SRP. The resilience and risk-based planning approach utilizes a suite of planning models, which collectively comprise the Integrated Resilience & Risk Investment Model developed by 1898 & Co. The model's actionable investment activities prioritize resilience and risk-based investments based on available data, analytics models, and benefit-cost analyses.

The approach calculates the resilience and risk improvement at the investment activity, program, substation, and measure levels. Resilience and risk benefits for resilience investment activities are estimated from a customer-centric perspective, in alignment with subsection (c)(2)(A)(iii) of the Resiliency Rule. The customer benefits are shown in terms of the:

1. Decrease in utility restoration costs;
2. Decrease in the number of customers impacted and the duration of the overall outage; calculated as CMI and monetized customers interrupted minutes ($CMI) using the Department of Energy's (DOE's) Interruption Cost Estimate (ICE) Calculator to assign a dollar value to CMI based on the duration of the outage and customer type; and
3. Qualitative benefit streams for difficult-to-quantify factors like safety.

1.2.1 Understanding Benefit Cost Ratio as a Resiliency Prioritization Tool

For the Distribution Overhead Hardening, Distribution System Protection Modernization, and Communication Modernization measures, the output of the evaluation is the following:

- avoided reactive and restoration costs;
- avoided customer outages, as measured in CMI; and
- $CMI.

Utilizing the avoided restoration cost, avoided $CMI, and the estimated resilience investment level, the evaluation calculates the resilience and risk benefit-cost ratio (BCR) for each investment activity, program, and substation.

$$Resilience\ \&\ Risk\ BCR = \frac{Lifecycle\ PV\ Avoided\ Restoration\ Costs + Lifecyle\ PV\ Avoided\ \$CIM}{Lifecyle\ Resilience\ Investment}$$

The Resilience & Risk BCR, as used in this analysis, is a single value that represents complex modeling of resiliency events, infrastructure vulnerability, infrastructure rebuild costs, and other financial factors to provide a robust and reliable measure to evaluate individual resiliency investments from a quantified customer benefit perspective.

This single value, Resilience & Risk BCR, for each investment activity[6] aggregated to each circuit, constitutes a sophisticated multi-factored analysis. The results of this evaluation are measured at the substation level to align with SPS's execution approach. The Resilience & Risk BCR incorporates the following factors for each investment activity (over 17,500 investment activities modeled, as shown in Table 5-2 below) for each measure:

Resiliency Events

- Range of resiliency events – 20 different event types;
- Frequency of those resiliency events – averaging 132 per year;
- Location of events by county; and
- The expected asset-level probability of failure based on historical customer impacts and infrastructure vulnerability.

Infrastructure Vulnerability

- Number of assets within each investment activity;
- Age of the assets within each investment activity and their expected lives;
- Known equipment original-design vulnerabilities (*e.g.*, Open Wire Secondary);
- Structural loading of infrastructure;
- Vegetation density around each span of conductor for overhead investments;
- Number of downstream customers for each investment activity;

[6] 1898 & Co. identified investment activities at the distribution circuit protection zone level. This approach is described in more detail in Section 5.1.

- Types of customers (residential, small C&I, large C&I, and critical customers[7]) for each investment activity; and
- The accessibility of the infrastructure in terms of street access and location within SPS's service area (urban, suburban, rural).

Infrastructure Rebuild Costs

- The cost to restore the infrastructure and system for each event type and infrastructure vulnerability.
- The resilience investment needed to mitigate the events including:
  - Number of assets, and
  - Location of the assets (restricted access[8] and urban, suburban, rural).

Financial Factors

- Discounted cash flow methodology over the lifecycle of the infrastructure in mitigating events over the next 50 years - 2.5% for escalation, 6.5% for discount rate (consistent with the values established in SPS's most recent base-rate proceeding).
- The DOE ICE calculator to evaluate the cost of an outage for the range of customer types and outage durations.

Most of these factors (especially the resiliency event, infrastructure vulnerability, and investment level) are requirements of the Resiliency Rule. Additionally, 1898 & Co. has carefully integrated all of these factors within each model to estimate benefits objectively, consistently, and precisely for each investment activity.

This approach makes the BCR value a robust and reliable measure to help understand the justification for resilience investment activities. This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for SPS customers. **Additionally, given the alignment of these factors to the Resiliency Rule (resilience events, system vulnerabilities, avoided utility restoration costs, avoided customer outages, etc.),**

[7] As designated by SPS.
[8] Restricted access refers to assets that do not have street access and are located in fields or accessible only by dirt roads, as described in the Direct Testimony Jole (pg. 18).

the BCR is a metric that aligns the investment activity to the Resiliency Rule. This value is thus an appropriate metric to guide resilience investment on the SPS system.

While the Resilience & Risk BCR incorporates many factors, it does not capture all benefit streams. The list above shows that the BCR incorporates most of the objective resiliency related factors within the quantified benefits assessment. 1898 & Co. recognizes that more subjective or difficult-to-quantify risk factors have not been incorporated into the evaluation. Two key subjective factors are safety and improving service to areas of lower performance (*i.e.*, *customers* experiencing multiple interruptions or feeders that do not satisfy the PUCT's reliability rule). The Resiliency Rule specifically lists prioritizing "areas of lower performance" as a factor the Commission must consider in determining both whether a utility's plan is in the public interest and the extent to which the plan is expected to enhance system resiliency.[9] The Resilience & Risk BCR should be utilized as a key tool in prioritizing and selecting investments, in concert with other criteria that incorporate benefits streams not included within the quantified evaluation as described above. Incorporating the quantitative and qualitative assessments together is a powerful decision-making tool for utility investments.

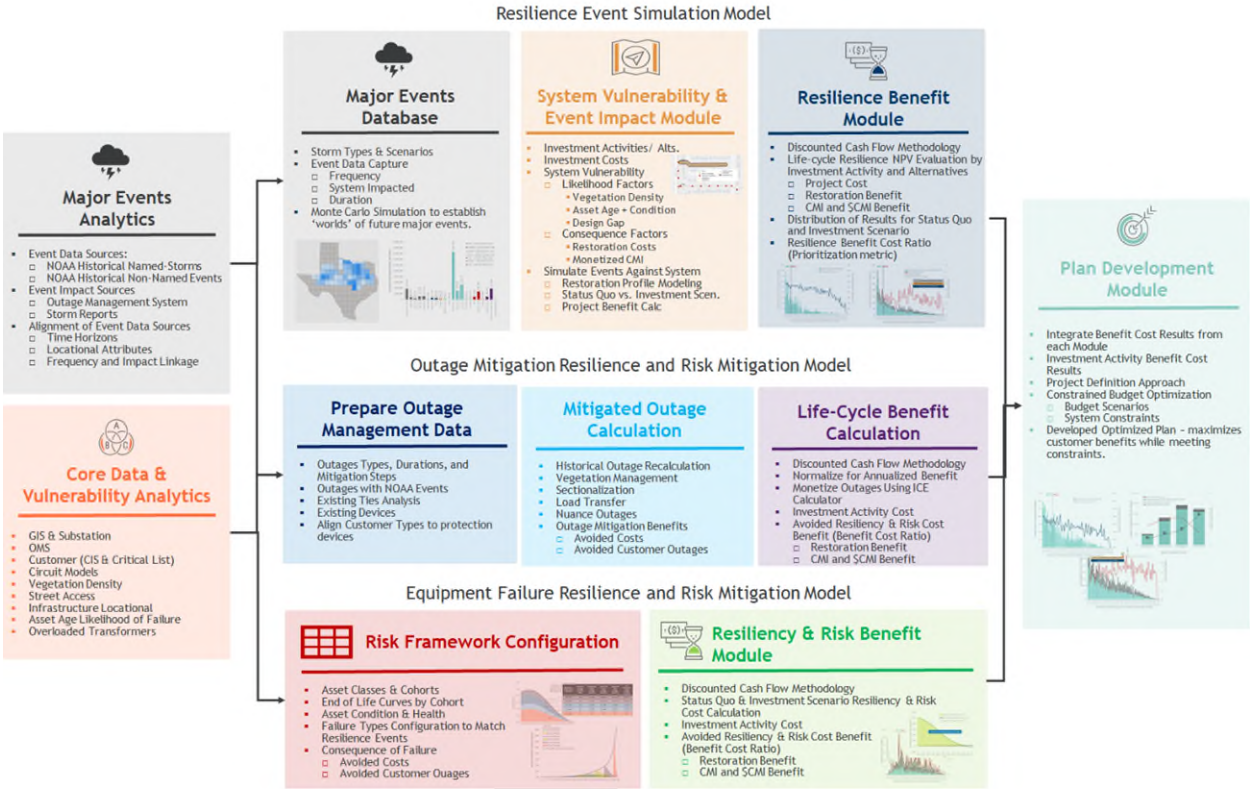
1898 & Co.'s evaluation does not directly include safety-related benefit streams. Rather, when evaluating benefit-cost results, 1898 & Co. balanced the quantified benefits results and safety-risk mitigation. For investments with BCR less than 1.0 but greater than 0.9, mitigating the general safety risk and other qualitative considerations would provide sufficient direct benefits such that the total benefits would be in excess of cost. Investment activities with a BCR less than 0.9 should be evaluated on a case-by-case basis, as direct quantifiable benefits are not the only consideration influencing investment activity justification. Benefits like improving service quality to areas of lower performance or mitigating specific safety risks, such as wildfire risk, may provide justification for pursuing investments with a lower BCR value and should be considered in the investment decision. The results presented throughout this report include the investment level with a BCR greater than 0.9.

[9] 16 TAC § 25.62(d)(4)(A) and (d)(4)(C)(i)(III).

1.2.2 Integrated Resilience & Risk Investment Model Overview

Figure 1-5 provides an overview of the Integrated Resilience & Risk Investment Model. The Integrated Resilience & Risk Investment Model employs a data-driven decision-making methodology using sophisticated algorithms to calculate the resilience and risk benefits for each potential investment activity that makes up each measure. These resilience and risk benefits are estimated in alignment to the Resiliency Rule as noted above.[10]

Figure 1-5: Integrated Resilience & Risk Investment Model



The model first includes foundational data, including the historical resiliency events that impacted the SPS system and SPS's asset register and equipment characteristics, which are used to determine the unique vulnerabilities of SPS's system. This information feeds the rest of the model.

The model includes three analytics models (Resilience Event Simulation Model, Outage Mitigation Risk & Resilience Model, and Equipment Failure Resilience & Risk

[10] 16 TAC § 25.62(c)(2)(A)(iii).

Mitigation Model). Each of these analytics models estimates the expected avoided costs (including resilience event costs) and avoided customer outages (including resilience event outages). Each analytics model was designed to estimate the resilience and risk benefits of different resiliency investments based on the available data, asset types, benefit streams, and failure types. Each analytics model provides a direct link between historical resiliency events and outages on SPS's system with sufficient detail to estimate how future resiliency events will impact the system under different investment scenarios. Said another way, these models allow for a quantitative analysis of how SPS's system responded to a historical resiliency event and how that same system would have responded had certain resiliency measures been in place. This is further discussed in Section 4.0. This allows 1898 & Co. to demonstrate objectively how investment in a particular resiliency measure can improve the system's ability to prevent, withstand, mitigate, or more promptly recover from an event.

Finally, the model includes a plan-development module that integrates the benefit-cost results from each of the analytics models, normalizes to avoid double-counting benefits, and captures investment-activity bundling approaches to maximize the efficiency of SPS's implementation of the SRP. The output of this module is a list of resilience investment activities for SPS to develop an executable plan that balances maximizing customer benefits and execution constraints for each measure.

1.3 Benefit-Cost Analysis Results

Table 1-3 provides an overview of the BCA performed by 1898 & Co. The investment dollars shown in this report are in 2024 dollars to match the basis for the benefits basis, whereas in other parts of the SRP the investment dollars are shown in nominal dollars, or dollars of the day. Nominal dolllars include escalation.

Table 1-3: Benefit-Cost Evaluation Summary

Measure / Program	Avg. BCR for Investment with BCR≥1	Investment with BCR ≥1	Investment with BCR ≥0.9	% Improvement in CMI for BCR ≥1
Distribution Overhead Hardening Measure (Distribution Circuit Hardening Rebuild Program)	2.1	$1.76B	$1.93B	54%
Distribution System Protection Modernization: Mainline Automated Reclosing Deployment Program[11]	4.3	$76.1M	$79.7M	38%
Distribution System Protection Modernization: Lateral Reclosing Deployment Program	1.9	$1.7M	$2.0M	21%
Communication Modernization[11]	N/A	$104.6M	$104.6M	N/A
Total	**2.1**	**$1.94B**	**$2.12B**	**N/A**

The table shows nearly $2 billion of potential resiliency investment on the SPS system with benefits in excess of costs for customers. These potential investments have a BCR of 2.1, demonstrating a significant opportunity to reduce customer outages, by over 50% for circuits where hardening investment is made and by almost 40% for mainline automation. Most of this potential investment, over 90%, is in the Distribution Overhead Hardening Measure.

Figure 1-6 shows the BCR results for the Distribution Overhead Hardening Measure if the Mainline Automated Reclosing Deployment program is implemented across the entire SPS system. The figure summarizes the BCR results for 11,793 protection zones. As the figure shows, the overall total potential investment level would be approximately $3.24 billion. Approximately $1.76 billion, or 54.3% of the total potential investment level, has quantified benefits in excess of cost.

[11] As described in Section 6.3.3 the Communication Modernization investment enables the full effectiveness of the mainline automated reclosing deployment program. Section 6.2.4.1 shows a BCR of 4.3 for the mainline automation program. As shown in Section 6.3.3, the combined program BCR is 1.8.

Figure 1-6: Distribution Overhead Hardening Measure Resiliency & Risk BCR Summary Assuming Mainline Automation on All Circuits

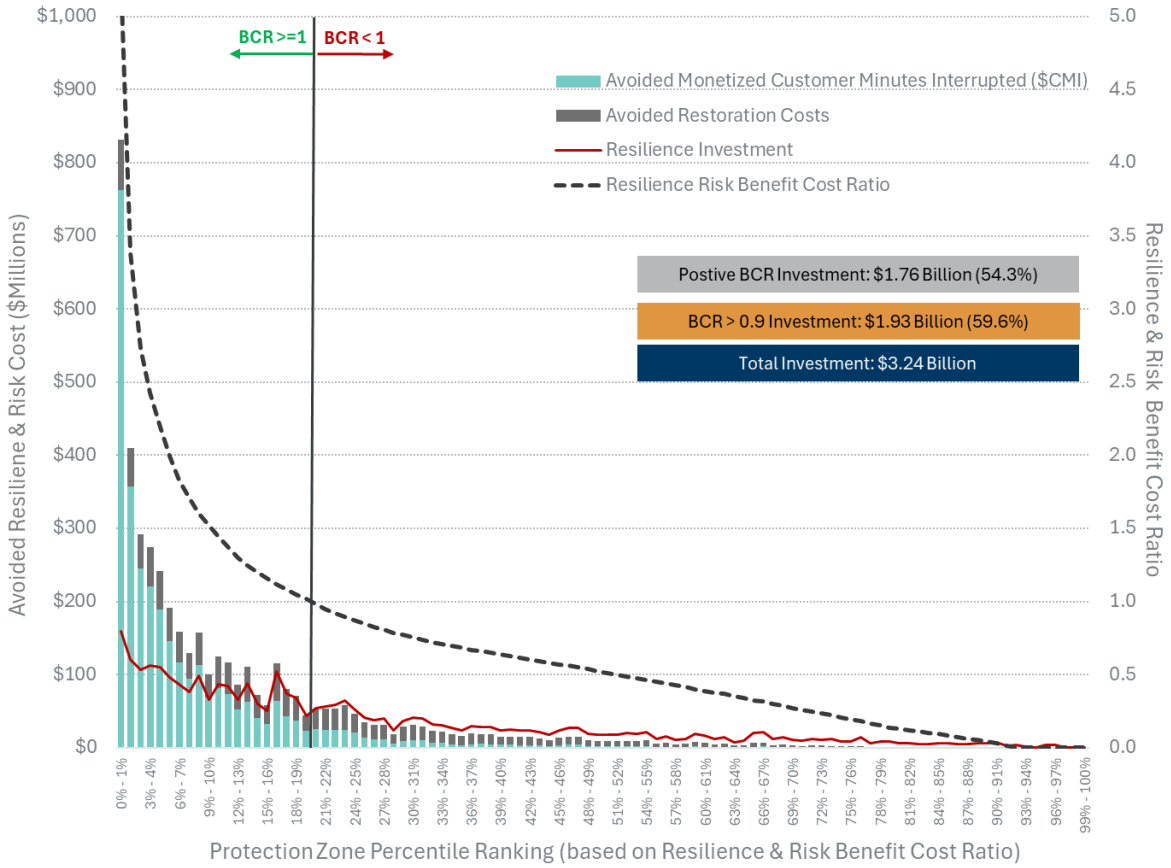
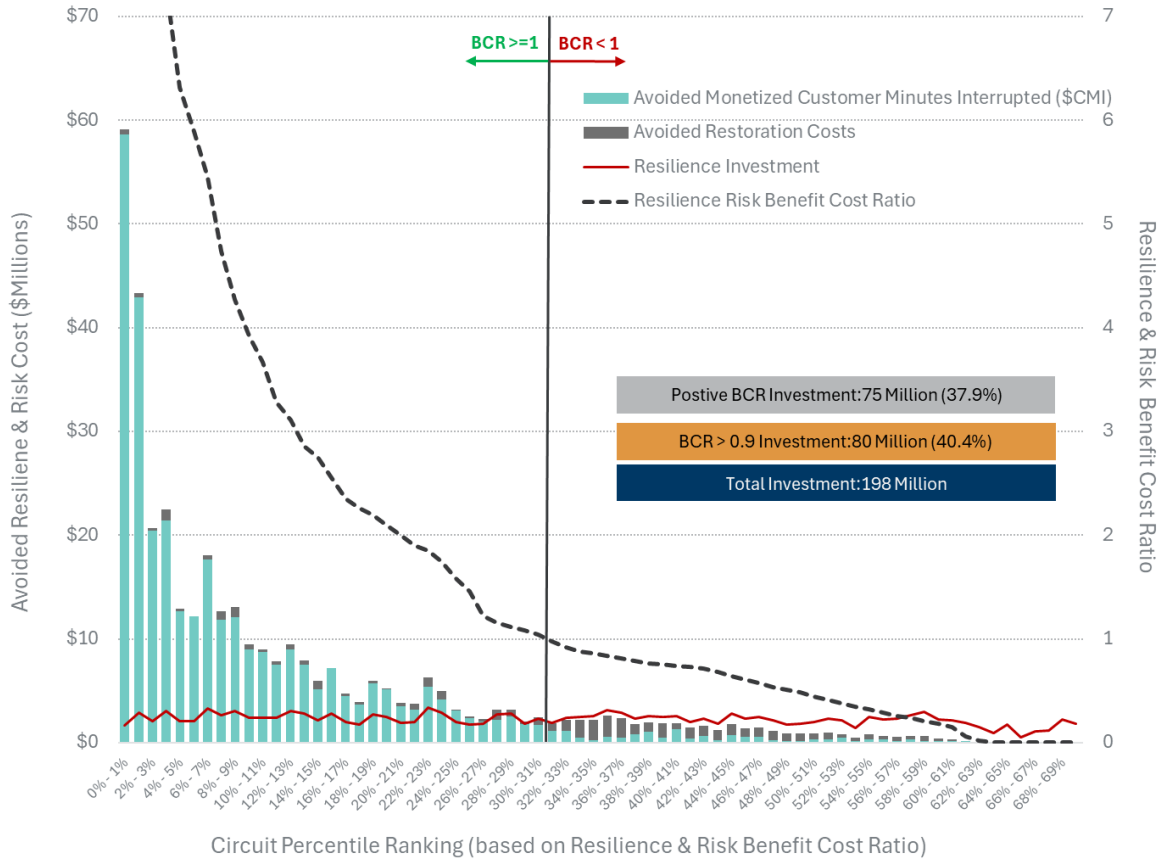


Figure 1-7 shows the BCR result for the Mainline Automated Reclosing Deployment program, the main program for the Distribution System Protection Modernization Measure. The figure summarizes the BCR results for 459 circuits. If this program were applied to the entire SPS distribution system, the overall investment level would be approximately $198 million. The figure shows that approximately $75 million, or 38% of the total potential investment level, has quantified benefits in excess of cost.

Figure 1-7: Mainline Automated Reclosing Deployment Program Resiliency & Risk BCR Summary



The Communication Modernization program is key to unlocking the Distribution System Protection Modernization measure's full benefits, which derive from the ability to automate sectionalization customer load transfer to adjacent circuits during outages. Because of this, it is appropriate to include the costs of this measure with the costs and benefits of the Distribution System Protection Modernization measure, specifically the Mainline Automated Recloser Deployment program. SPS provided 1898 & Co. with the expected scope and costs of the activities described above. SPS estimates the capital expense of this measure at $104.6 million. To evaluate the BCR of this measure, 1898 & Co. estimated the excess quantified benefits from the Mainline Automated Recloser Deployment program.

Based on this, the direct investment in the Mainline Automated Reclosing Deployment program produces benefits of approximately $330 million with an investment of

approximately $76 million, providing a BCR of 4.3 and excess benefits of approximately $254 million. The additional investment of $105 million is foundational to achieve these excess benefits. When this additional investment is included, the BCR of the combined programs is 1.8 ($330 / ($76 + $105)). This shows that the investments in the Communication Modernization measure are expected to produce benefits in excess of costs for customers.

1.4 SRP Investment & Benefit-Cost Analysis Results

In developing the implementation approach to select specific investment activities, SPS considered the following:

- Organizational objectives, mainly deploying system protection modernization broadly across Wildfire Tiers 2 and 3 zones;
- Execution realities in terms of equipment availability and other execution constraints; and
- The BCR, as outlined above.

Table 1-4 provides a summary of the investment level for each of the measures evaluated by 1898 & Co. by wildfire tier and investment activity type. The table also includes the wildfire-specific investment activities that were not evaluated by 1898 & Co. For the measures evaluated by 1898 & Co. the SRP's proposed investment level is $425.1 million (in 2024 dollars).

Table 1-4: SRP Investment Summary (2024 $ in Millions)

Wildfire Tier / Investment Activity Type	Distribution Overhead Hardening Measure	Distribution System Protection Modernization Measure		Communication Modernization	Total
	Distribution Circuit Protection Hardening	Mainline Automated Reclosing Deployment Program	Lateral Reclosing Deployment Program		
Wildfire Tier 3	**$155.8**	**$37.8**	**$0**		**$193.6**
BCR Analysis Activities	$154.1	$35.0	$0		$189.1
Wildfire Specific Activities	$1.7	$2.7	$0		$4.4
Wildfire Tier 2	**$61.2**	**$22.3**	**$0**		**$83.5**
BCR Analysis Activities	$60.6	$21.1	$0		$81.7
Wildfire Specific Activities	$0.6	$1.3	$0		$1.9
Wildfire Teir 1	**$17.8**	**$23.6**	**$2.0**		**$43.4**
BCR Analysis Activities	$17.8	$23.6	$2.0		$43.4
Wildfire Specific Activities	$0	$0	$0		$0
Total	**$234.8**	**$83.7**	**$2.0**	**$104.6**	**$425.1**
BCR Analysis Activities	$232.5	$79.7	$2.0	$104.6	$418.8
Wildfire Specific Activities	$2.4	$4.0	$0		$6.4

The Distribution Overhead Hardening measure accounts for most of the investment with 55.2% of the total, followed by Communication Modernization at 24.6%. The Mainline Automated Reclosing Deployment Program is approximately 19.7% of the total, with the Lateral Reclosing Deployment making up the smallest portion at 0.5%. From a wildfire tier perspective, Tier 3 includes approximately 60% of the total for the Distribution Overhead Hardening and Distribution System Protection Modernization measures. Wildfire Tier 2 accounts for approximately 26% of the total and Tier 1 at 14%.

Table 1-5 shows the BCA results for the SRP. As noted in the table, the investment dollars in the table do not include any of the wildfire-specific activities from Table 1-4. The overall BCR for the proposed SRP investments that 1898 & Co. evaluated is approximately 3.4.

Table 1-5: SRP Benefit-Cost Evaluation Summary

Measure / Program	Avg. BCR	SRP Investment (2024$)	Benefits (2024$)	% Improvement in CMI
Distribution Overhead Hardening Measure (Distribution Circuit Protection Hardening Program)	4.7	$232.5M	$1,094.5M	58%
Distribution System Protection Modernization: Mainline Automated Reclosing Deployment Program[12]	4.2	$79.7M	$333.0M	37%
Distribution System Protection Modernization: Lateral Reclosing Deployment Program	1.8	$2.0M	$3.5M	21%
Communication Modernization[12]	N/A	$104.6M	N/A	N/A
Total	**3.4**	**$418.8M**	**$1,431M**	**N/A**

These investments also show a significant improvement in customer outages, approximately 58% for circuits where hardening investment is made and approximately 37% for mainline automation.

1.5 Conclusions

This section summarizes the conclusions of 1898 & Co.'s assessment of the resiliency investment activities that make up SPS's SRP as evaluated within 1898 & Co.'s Integrated Resilience & Risk Investment Model:

- The resilience and risk BCR value is a robust and reliable measure to help understand the justification for resilience investment activities. **This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for customers.** Additionally, given the alignment of the BCR factors to the Resiliency Rule, the BCR aligns the investment activity to the Resiliency Rule.
- **The benefit cost evaluation shows significant opportunity to improve distribution system resiliency for SPS customers** with nearly $2 billion of investment with a BCR greater than or equal to 1.0 for the quantified measures

[12] As described in Section 6.3.3 the Communication Modernization investment enables the full effectiveness of the mainline automated reclosing deployment program. Section 6.2.4.1 shows a BCR of 4.3 for the mainline automation program. As shown in Section 6.3.3, the combined program BCR is 1.8.

shown in Table 1-3. Each of these investments provides quantified customer benefits in excess of cost.

- **The SRP measures evaluated by 1898 & Co. are expected to provide benefits in excess of costs for SPS customers.** The investment level of $418.8 million is expected to provide $1,431 million of benefits with an average BCR of 3.4. All of the investment activities included in the SRP have a BCR ≥ 0.9.
- **The quantified benefit-cost analysis shows SPS's proposed investment level under the SRP is less than the potential investment with a BCR greater than or equal to 1.0.** SPS's proposed investment under the SRP is approximately 22% ($418.8 / $1,940) of the total potential investment in investment activities with a BCR ≥ 1.0, and 20% ($418.8 / $2,120) of the total potential investment in projects with a BCR ≥ 0.9.
- **Communication Modernization is a key investment to unlock the full potential of other investments in the SRP, particularly investments in the Distribution System Protection Modernization measure.** Without Communication Modernization, several of those investments will be less secure and will not offer the full range of benefits they are capable of providing. The quantified excess benefits from other measures that the Communication Modernization measure enables are in excess of this measure's life-cycle costs. The combined BCR of the Distribution System Protection Modernization measure for investments with a BCR ≥ 1.0 and the Communication Modernization measures is 1.8.
- **The plan will benefit all SPS customers**. Avoided outage restoration costs are shared by all distribution customers. Additionally, distribution customers will experience fewer storm outages from both direct and indirect causes. Direct benefits are realized by those customers whose infrastructure is located directly downstream of the resiliency investment. Indirect benefits are realized by all distribution customers, since storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.
- **The resilience investment benefits are conservative**. First, the benefits outlined above are only direct benefits to specific resiliency measures and do

not factor in the indirect benefits from lower overall storm restoration durations. Second, the DOE ICE Calculator is likely conservative for residential customers, as the underlying data pre-dates the significant advancements in societal use of electronic devices and technologies or trends toward work-from-home arrangements (see Section 5.5 for additional information), and the DOE ICE Calculator has not been updated to account for this societal shift. Third, the quantified benefit-cost assessment has carefully included the full cost of implementing resiliency investments; however, the full level of benefits has not been captured. Specifically, the evaluation has not incorporated qualitative benefits associated with enhanced safety or service improvement in areas of lower performance.

- **The SRP is an integrated portfolio** of measures and investments designed to collectively prevent, withstand, mitigate, and more promptly recover from the risks posed to SPS's system from a wide range of resiliency events. Excluding any programs within the proposed measures may impact the expected benefit of the other remaining programs or measures (*see* Section 2.4).

2.0 Introduction

Over the last decade, extreme weather events have impacted society more and more: from hurricanes in Florida and the Gulf coast; nor'easters along the east coast; polar vortexes, ice storms, and other winter events in the mountain region and Midwest all the way to the east coast; fires in the west and the Texas panhandle; and most notably for Texas Winter Storm Uri in 2021 and Hurricane Beryl in 2024..

At the same time, customer expectations for the availability of the grid have increased dramatically over the last several decades. Decades ago, grid outages were seen as an inconvenience for customers. Today, these outages can cause stress, physical and economic harm, and even put society's most vulnerable at risk, due to the proliferation of life-saving electronic equipment in people's homes. Additionally, today's society is far more integrated than in the past. The recent supply-chain disruptions following the global pandemic have revealed to us just how interconnected our society and global economy have become. Compounding this challenge is the expected trend towards more dependence on the grid with the acceleration of electrification in applications, such as home heating, oil and gas activity, commercial fleet electrification, and electric vehicle adoption, to name a few. More than ever, today's customer demands that the electric grid be consistently available.

One of the most important actions Texas can take to prepare for the aforementioned extreme weather events is to make the electric grid more resilient. When the grid can better withstand the impacts of Proactive investment in grid resilience also allows utilities to design integrated programs to address all phases of resilience (described below), which in turn will reduce event-related restoration costs and outage times. This will ultimately save money for Texas families and businesses by allowing them to get back on their feet more quickly after extreme weather strikes. The Resiliency Rule encourages this kind of proactive investment philosophy.

This section of this Report outlines a conceptual framework for understanding grid resilience as envisioned in the Resiliency Rule.

2.1 Resilience Definition

The Merriam-Webster dictionary defines resilience as:

1. the capability of a strained body to recover its size and shape after deformation caused especially by compressive stress.
2. an ability to recover from or adjust easily to misfortune or change.[13]

Merriam-Webster elaborates on the definition:

> In physics, resilience is the ability of an elastic material (such as rubber or animal tissue) to absorb energy (such as from a blow) and release that energy as it springs back to its original shape. The recovery that occurs in this phenomenon can be viewed as analogous to a person's ability to bounce back from a jarring setback.[14]

These definitions provide a conceptual understanding of resilience, but additional exploration is needed to understand the term in the context of electric power systems. While there is general agreement within the industry around the major elements of resilience, definitions vary. Other definitions of resilience from grid stakeholders are:

- **IEEE PES PES-TR83 Report—Resilience Framework, Methods, and Metrics for the Electricity Sector:** The ability to protect against and recover from any event that would significantly impact the grid.
- **CIGRE WG C4.47:** Power system resilience is the ability to limit the extent, severity, and duration of system degradation following an extreme event.
- **FERC**: The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such event.
- **DOE:** The ability of a power system and its components to withstand and adapt to disruptions and rapidly recover from them.

[13] Resilience. (n.d.). Merriam-Webster Dictionary. https://www.merriam-webster.com/dictionary/resilience
[14] *Id.*

In a 2013 paper, the National Association of Regulatory Utility Commissioners (NARUC) offered its own definition of resilience that is simple and easy to understand:

> Robustness and recovery characteristics of utility infrastructure operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event. In other words, it is the gear, the people, and the way the people operate the gear immediately before, during and after a bad day that keeps everything going and minimizes the scale and duration of any interruptions.[15]

Before that, the National Infrastructure Advisory Council (NIAC) provided a definition that is often quoted. It states that resilience is:

> The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.[16]

The NIAC definition includes a system's ability to absorb and adapt. These important characteristics were also used by Argonne National Laboratory (ANL) in its work on state and social resilience and were incorporated into Pacific Northwest National Laboratory's (PNNL) work on the resilience impacts of transactive energy systems. The ANL approach can be used to break resilience into four phases that also align with NARUC's elegantly simple description—the difference being that ANL explicitly includes the ability of the system to recognize and mitigate potential failures before they happen. These four phases are described below:

- **Prepare (Before)**
  The grid is running normally, but the system and its operators are preparing for potential disruptions.

[15] Keogh, M., Cody, C., & NARUC Grants & Research. (n.d.). *Resilience in Regulated Utilities*. https://pubs.naruc.org/pub/536F07E4-2354-D714-5153-7A80198A436D#:~:text=Resilience%20%2Fri%CB%88zily%C9%99ns%2F%20noun%2C%20regulatory,an%20extraordinary%20and%20hazardous%20event.
[16] NIAC Working Group Members. (n.d.). CRITICAL INFRASTRUCTURE RESILIENCE FINAL REPORT AND RECOMMENDATIONS. https://www.cisa.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf

- **Mitigate (Before)**
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption.
- **Respond (During)**
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux, and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- **Recover (After)**
  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.[17]

While the term "resiliency" is not defined in the Resiliency Rule, the rule provides guidance regarding the goals of a resiliency plan that sheds light on how the PUCT views resiliency. Notably subsection (c)(1) of the Resiliency Rule states that "[a] resiliency plan is comprised of one or more measures designed to prevent, withstand, mitigate or more promptly recover from the risks posed to the electric utility's transmission and distribution systems by resiliency events ...." From this we can surmise that a proper resiliency measure under the Resiliency Rule is one that enables a system to "prevent, withstand, mitigate or more promptly recover" from a particular resiliency event.

The definitions of resilience quoted above can be used to form a conceptual framework in which to better understand and evaluate initiatives to improve grid resilience. This framework is discussed in the following subsection.

2.2 Resilience Conceptual Framework and Commission Substantive Rule § 25.62

The resilience of a utility system is a function of many factors, but the two main factors are: (1) the frequency and types of events to impact the system; and (2) the vulnerability characteristics of the infrastructure that makes up the system. Obviously,

[17] Argonne National Laboratory. (n.d.). *Resilience Measurement Index: An Indicator of Critical Infrastructure Resilience*. https://publications.anl.gov/anlpubs/2013/07/76797.pdf

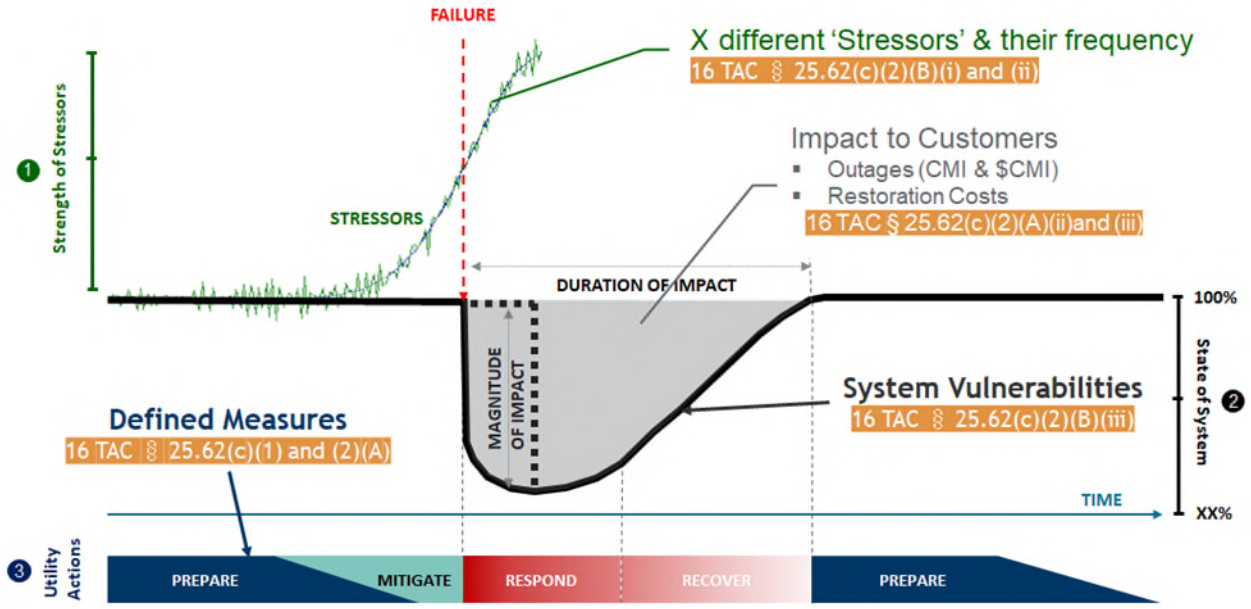
more frequent and more intense resiliency events make grid resilience more challenging. Second, the unique vulnerability characteristics of a utility's system will change the overall outcome to the system in the face of a given resiliency event. The following are examples of key system characteristics or vulnerabilities that will impact the resilience of the grid:

- Quantity of exposed infrastructure;
- Vegetation density around infrastructure;
- Age and condition of exposed infrastructure;
- Loading of the infrastructure, structural (e.g., span length);
- Equipment types with known deficiencies (*e.g.*, Open Wire Secondary);
- Level of system sectionalization (size of circuits); and
- Number and mix of downstream customers.

The combination of resiliency events and system vulnerabilities provides additional challenges for grid resilience. Individual resiliency events by their nature are unpredictable and do not impact an area uniformly. Grid stakeholders could be "lucky" or "unlucky" depending on how the risks posed by a resiliency event impact the grid. The power system will have a different resilience response to a thunderstorm with pockets of high winds in older, vegetation-dense neighborhoods than in a newer, suburban neighborhood where distribution facilities are underground. If a resiliency event is more localized to the suburban area, the grid may appear to be resilient, but should the event move 10 miles in a different direction, it could cause significant outages in an older, vegetation-dense neighborhood. The combination of these two factors—events and vulnerabilities—have profound impacts on a grid's measured resilience.

1898 & Co. utilizes a Conceptual Resilience Framework to understand both factors and how improvements to the grid can improve system resilience. This framework provides a quantitative look at the effectiveness of resiliency measures as required by subsection (c)(2)(A)(ii) of the Resiliency Rule. Figure 2-1 represents this conceptual view of resilience and its alignment to the Resiliency Rule.

Figure 2-1: Conceptual Resilience Framework & Resiliency Rule



The framework is broken up into three components. The first component is the relative strength of a "stressor" or resiliency event. This is the occurrence that tests or impacts the system. Examples of events could be a tornado, ice storm, thunderstorm, wind, or other event. Each stressor has a different expected frequency of occurrence and relative strength. The green line represents the underlying resiliency event that is stressing the grid, which increases in magnitude until it causes an outage. The origin of the stress may be high winds during a storm, ice accumulation on facilities, intentional acts by a bad actor, or another event. Section 2.3.1 below includes additional discussion on stressors and why investment is needed. Each "stressor" has a different expected frequency of occurrence and relative strength.

The second component is the "State of System," which is represented by the black line. This line can represent the state of the entire system or of discrete parts of the system (*e.g.*, individual substations or distribution circuits). The "pit" depicted after the resiliency event occurs represents the impact on a system in terms of the magnitude (vertical) and the duration (horizontal). For utilities, this should be measured from a customer-centric perspective, mainly in the number and duration of customer outages and the cost to restore the system to a steady state. This is captured

in the Resiliency Rule's requirement to estimate the benefits of investments in terms of mitigated system restoration costs, reduced frequency or duration of outages for customers, and improved overall service reliability for customers. *See* 16 TAC § 25.62(c)(2)(A)(iii). The State of System is driven by grid characteristics or vulnerabilities, as outlined above. Sections 2.3.2 and 5.0 below include a review of system vulnerability characteristics for SPS. Generally, for an electric utility, overhead circuit infrastructure, a greater number of aged and vegetation-exposed assets, span length, a limited number of ties, and high downstream customer counts will cause a system to be less resilient against events.

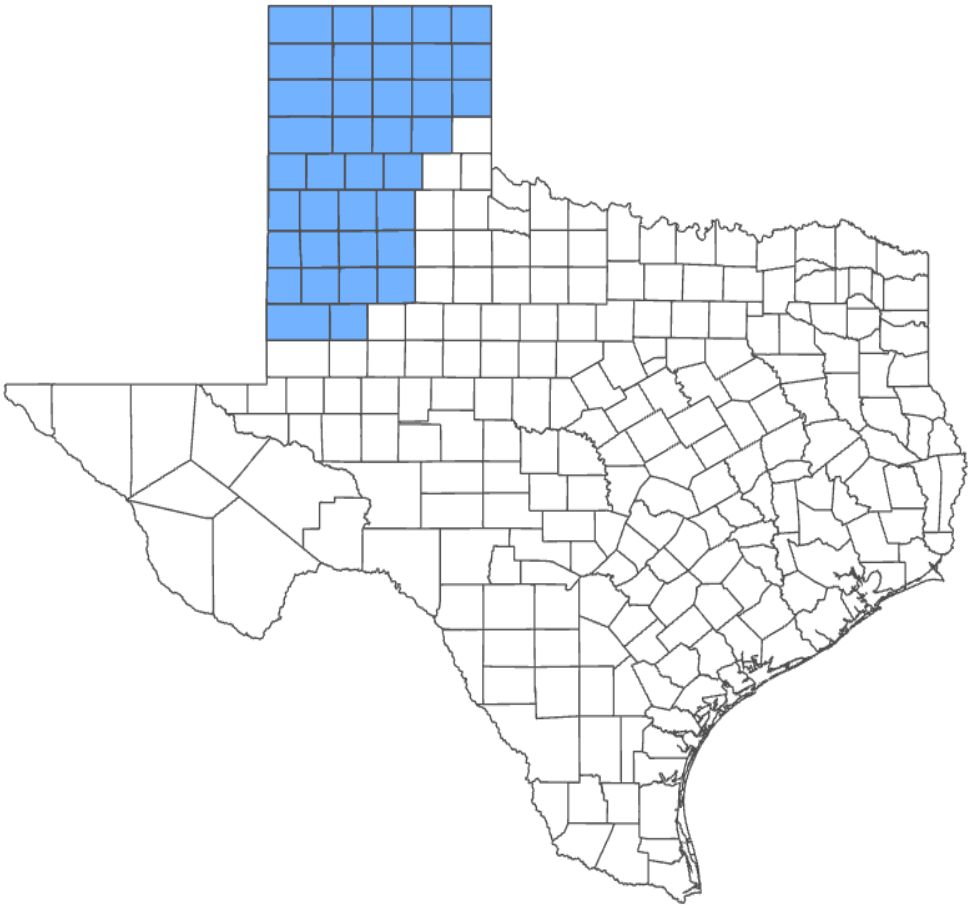
The third component of the resilience framework is the utility's actions as they prepare for, mitigate, respond to, and recover from the stressors that caused major disruptions to the grid. Within this third component, the utility can take action to minimize the disruptions to the state of the system. The "prepare" phase can be immediately before a resiliency event or well in advance of a resiliency event. In the case of preparations undertaken immediately before a resiliency event, grid owners and operators may mobilize mutual assistance crews from other utilities and stage equipment to enable faster response during the event. Further in advance of a resiliency event, grid owners and operators may invest in grid hardening or modernization initiatives to mitigate the risks posed by resiliency events. **The investment focus of this report is on this advanced preparation planning phase and the investments that can be made to mitigate the impacts of future resiliency events. The modeling focus of this report is on the respond and recover phases following a resiliency event.** In the "respond" phase, grid operators are assessing damage and prioritizing response. This phase is often unpredictable, as efforts to assess the full impact can be delayed for safety reasons. In the "recover" phase, grid operators understand the state of the system and how to restore it to normal operations. Section 6.0 outlines SPS's proposed categories of resilience investments (Measures) in the "prepare" phase to decrease the impact of grid disruptions on customers.

The conceptual framework can be used to depict a specific distribution circuit, a utility's distribution system, or the entire grid. Figure 2-1 represents a specific distribution circuit and the impact of the resiliency event on only that circuit. If Figure 2-1 were used to represent the impact on the whole SPS system, it would represent the aggregated impacts of the resiliency event, and the outages that resulted from it, on all of SPS's facilities. Note that whether the resilience conceptual framework is used to depict the impact of a resiliency event on a specific system segment or the overall distribution system, there is no pre-established quantification of time. Events may be measured in minutes, hours, or days, depending on the duration of the resiliency event and the time required for the system to recover.

2.3 Resilience Framework & SPS Service Area

This section provides additional context to understand the Resilience Conceptual Framework (and hence the Resiliency Rule) as applied to the unique characteristics of SPS's service area. The first thing to note is the size of the service area. Figure 2-2 shows the SPS service area. SPS's service area covers most of the Texas Panhandle, covering approximately 33,000 square miles and 37 counties. As a reference, the state of South Carolina is approximately 32,000 square miles. The service area spans 170 miles from east to west and 280 miles from north to south.

Figure 2-2: SPS Service Area



Given the size of SPS's service area, the number and types of resiliency events vary across the system. Some parts of the system are more exposed to winter-based weather events than others (*see* Section 2.3.1). Additionally, system characteristics and vulnerabilities vary significantly across SPS's system (*see* Section 2.3.2). Finally, the investment needed to mitigate the impacts of resiliency events must balance the need for comprehensive hardening that mitigates the risks posed by the greatest number of resiliency events for specific downstream customers, while also providing some level of protection for most customers across the system. The following sub-sections explore each of these resiliency factors (the range of events across SPS's service area, range of vulnerabilities across SPS's service area, and range of proposed SRP investments) in more detail to provide a better understanding of the complexity

in improving resiliency for SPS's customers as well as the challenge in modeling the expected benefits of resiliency investments for customers.

2.3.1 Overview of "Stressors" to Impact SPS's Service Area

To understand the types of weather-based resiliency events that impact SPS's service area and customers, 1898 & Co. mined event databases from NOAA. The database included Extreme Weather events. The NOAA databases showed 22 unique weather-event types across 8 different categories that impacted the SPS service area. Table 2-1 shows the 22 unique weather-based resiliency events that have impacted SPS's service territory. This evaluation excluded drought events since they are extremely long in duration and challenging to correlate to the outage management records. The benefit cost evaluation also excludes wildfire events. Thus, while the NOAA databases include 22 event types, this evaluation only addresses 20.

Table 2-1: Resiliency Events to Impact SPS's Service Territory

Extreme Weather	
Wind	11. Sleet
1. Thunderstorm Wind	12. Winter Storm
2. Lightning	13. Heavy Snow
3. Hail-Wind	14. Ice Storm
4. High Wind	15. Hail-Winter
5. Strong Wind	16. Blizzard
Flood	**Heat**
6. Flood	17. Heat
7. Heavy Rain	18. Excessive Heat
8. Flash Flood	**Drought**
Tornado	19. Drought
9. Tornado	**Cold**
Winter	20. Cold/Wind Chill
10. Winter Weather	21. Extreme Cold/Wind Chill
	Wildfire
	22. Wildfire

From 1998 through 2023, the SPS service area experienced approximately 3,443 distinct Extreme Weather events, or weather-based resiliency events, averaging approximately 132.4 per year. Section 3.0 includes additional information on the 20 types of NOAA-recorded weather events across SPS's service area, including their historical impact. The varied nature of the different event types across SPS's service area requires a suite of analytics models to apply the Resilience Conceptual Framework. This is further discussed below in Section 4.0.

2.3.2 Overview of Key System Vulnerabilities

As discussed above, the second main aspect of applying the Resilience Conceptual Framework to SPS's distribution system is understanding the unique characteristics of SPS's system and how those characteristics create vulnerabilities to resiliency events. The following are the key vulnerabilities of SPS's system:

- **Number of Assets** – The more infrastructure that is exposed to a given resiliency event, the more likely it is that the risks posed by the resiliency event will cause an asset to fail. For example, a section of the system with 100 assets presents more opportunities for failure than an equivalently sized section with only 10 assets, all else being equal. Thus, the size of SPS's system increases the likelihood that it will be impacted by a particular resiliency event. Sections 5.1 and 5.2 include additional detail on the number of assets within SPS's system.
- **Age of the Infrastructure** – The age of infrastructure has an inverse relationship with the resiliency of the infrastructure. Thus, the older a piece of equipment is, the more likely it is to fail during an event or stressor.
- **Vegetation Density** – Thickness, type, and prevalence of vegetation can have a negative impact on the resilience of a system. The greater the vegetation density around electrical infrastructure, the more vulnerable the infrastructure is to an outage.
- **Accessibility** – The easier the access to failed equipment, the shorter the time required to restore service. Assets that run through pastures with changing elevations where truck access is limited present unique challenges. Improving accessibility can be part of a resilience strategy.
- **Customer Count** – This is a major factor in the consequence of a failure. Failure of some assets may result in one customer losing service. In contrast, failure of a similar asset located elsewhere in the system may result in over 1,000 customers losing service. Some of those customers might also be designated as critical customers. Customer count and type are key factors in determining the amount of risk mitigated for each resilience investment.
- **Loading of Infrastructure (Structural)**– Equipment that is structurally loaded, especially in terms of span lengths, tends to have limited margins for tolerating abnormal conditions. This means that under extreme weather conditions—such as high winds or icing events—the equipment is more likely to reach its breaking point sooner, posing a higher risk of failure.

Each of these vulnerabilities can be assessed based on asset-specific attributes. The data used to evaluate vulnerabilities and consequences is described in Section 5.0 of this report.

2.4 SPS's SRP and Resilience & Risk Evaluation Overview

SPS and 1898 & Co. factored this breadth of resiliency events and system vulnerabilities in applying the Resilience Conceptual Framework to structure SPS's SRP. In developing the structure of the SRP, SPS and 1898 & Co. collaborated on measures focused on weather-based resiliency. Some of those measures also include additional investment activities to support wildfire resiliency. SPS directed 1898 & Co. on the particulars of the approach.

In structuring the SRP, SPS and 1898 & Co. strived to balance the following:

- A wide range of resiliency event types, frequencies, and impacts that stress the SPS system.
- A range of vulnerabilities across SPS's system, primarily including customer counts and types, vegetation density, infrastructure age and condition, equipment loading, and design standards that span decades of continuous utility operations.[18]
- The cost of investments to address the system vulnerabilities and improve the resilience of an individual asset or groups of assets.
- Infrastructure life-cycle cost management, incorporating other system issues (safety and capacity) and execution efficiencies. There are significant execution efficiencies in replacing or improving all equipment that is located in one geographical area together. Leveraging this efficiency provides benefits to SPS's customers in the form of avoided investment costs.

This balancing approach and application of the Resilience Conceptual Framework formed the structure of the SRP. SPS's SRP is an integrated portfolio of measures designed to mitigate the impacts of the risks posed by the diverse set of resiliency

[18] SPS's SRP addresses the inherent uncertainty regarding the vulnerabilities of specific pieces of equipment. After the Plan is approved, SPS will use field surveys and assessments to identify specific equipment vulnerabilities to be addressed by the resiliency measures.

events that SPS's system has faced in the past and must be prepared to face in the future, taking into account the unique characteristics of SPS's system and the vulnerabilities associated with those characteristics. Table 2-2 provides an overview of the structure of the SRP resulting from this balancing approach. The table also shows which programs 1898 & Co. evaluated. The programs not evaluated by 1898 & Co. are addressed in other parts of SPS's SRP application filing.

Table 2-2: SRP Structure & Programs Evaluated by 1898 & Co.

Measure	Measure Program	Systematic Approach Investment Activity Identification & Cost Estimating	Effectiveness and Benefits
Distribution Overhead Hardening	Distribution Circuit Hardening Rebuilds	X	X[19]
Distribution System Protection Modernization	Mainline Automated Reclosing Deployment	X	X[19]
	Lateral Reclosing Deployment	X	X
Communication Modernization	Communication Modernization		X
Operational Flexibility	Mobile Substation Equipment Procurement		
	Installation of Transmission Switches		
Wildfire Mitigation	Situational Awareness		
	Operational Mitigation		

With the structure of the SRP established, 1898 & Co. utilized a resilience and risk-based planning approach to identify, prioritize, and perform benefit-cost modeling to support the development of the SRP for the following measures:

- Distribution Overhead Hardening;
- Distribution System Protection Modernization; and

[19] Excludes any evaluation of the wildfire-specific investment activities that are a part of this program

- Communication Modernization.

Both the Distribution Overhead Hardening and Distribution System Protection Modernization measures include investment activities targeted to address weather resiliency and wildfire resiliency, with additional activities targeted solely targeting wildfire resiliency. While estimating the investment activity scope and cost of the weather resiliency portion of these measures, 1898 & Co. also estimated the scope and cost of the wildfire specific activities for each potential investment, as directed by SPS. This was done in alignment to SPS new standards and for execution synergies to deploy both weather resiliency and wildfire resiliency investment activities concurrently on the system. However, 1898 & Co. did not evaluate any benefits for wildfire mitigation. The resilience and risk-based planning approach employed for weather-based resiliency investment activities utilizes a suite of planning models, which collectively comprise the Integrated Resilience & Risk Investment Model developed by 1898 & Co. The Integrated Resilience & Risk Investment Model aligns with the Conceptual Resilience Framework and the Resiliency Rule, as outlined in Section 2.2.

The model uses the "theory" of the Conceptual Resilience Framework to develop an actionable investment plan that prioritizes resilience and risk-based investments based on available data, analytics models, and benefit-cost analyses.

The resilience and risk-based planning approach calculates the resilience and risk improvement at the investment activity, program, substation, and measure level. For the purposes of this evaluation, resilience and risk benefits are estimated from a customer-centric perspective, in alignment with Subsection (c)(2)(A)(iii) of the Resiliency Rule. The customer benefits are shown in terms of the:

1. Decrease in restoration costs;
2. Decrease in the number of customers impacted and the duration of the overall outage, calculated as CMI and $CMI; and
3. Qualitative benefit streams.

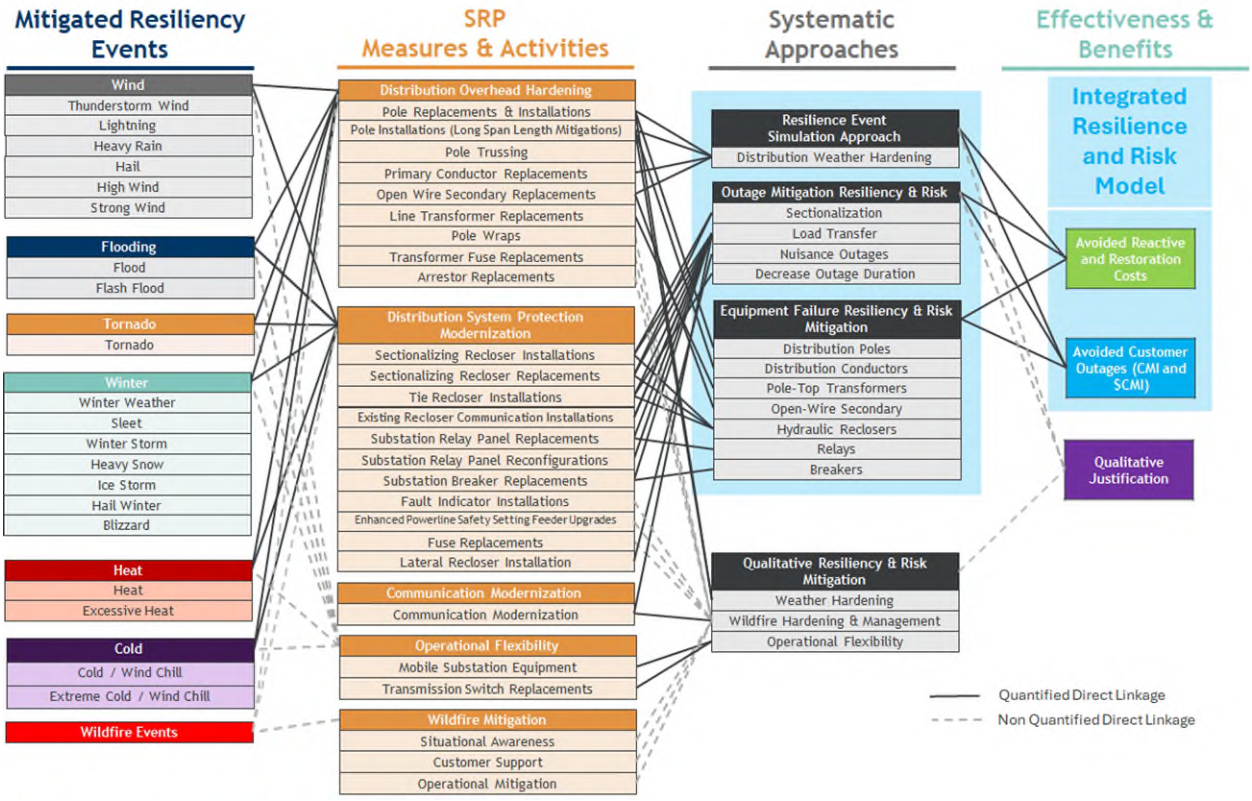
2.4.1 Measures, Systematic Approaches, and Benefits Assessments

Figure 2-3 shows the structure of SPS's SRP, the resiliency events, the measures that will mitigate the risks of those events, and the evaluation approach to identify investments that will decrease the impact of events to customers. The figure illustrates the application of the Conceptual Resilience Framework for the SRP and depicts the architecture of the evaluation utilized to identify resiliency investments that decrease the impact of resiliency events. The figure also shows how SPS's SRP aligns with the Resiliency Rule, specifically including:

- A list of SRP Measures as required by 16 TAC § 25.62(c)(2);
- The Resiliency Events and risks that the measures are intended to mitigate as required by 16 TAC § 25.62(c)(2)(B)(i);
- The use of a systematic approach to implement the SRP using particular investment activities, as required by 16 TAC § 25.62(2)(E); and
- Evidence of the effectiveness and benefits of each measure at mitigating resiliency events as required by 16 TAC § 25.62(c)(2)(A)(ii) and (iii).

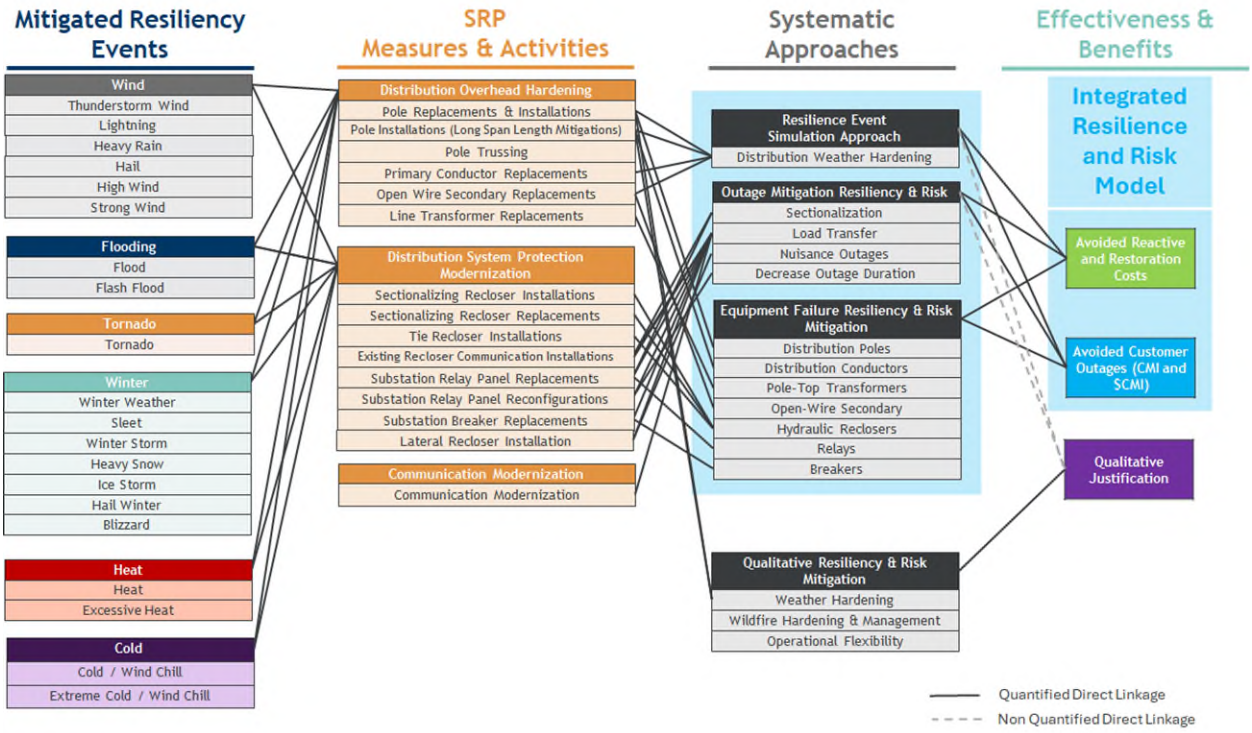
This figure demonstrates that the SRP is an integrated portfolio of measures and investments designed to collectively mitigate the impacts of risks posed to SPS's system by a wide range of resiliency events. The figure also shows that the integrated portfolio includes a suite of integrated analytics to identify investments that provide the most benefit for customers.

Figure 2-3: SRP Structure Overview and Resiliency Rule Alignment



As noted in Table 2-2, 1898 & Co. did not evaluate the Wildfire Mitigation or Operational Flexibility measures, nor the wildfire-specific investment activities that are a part of the Distribution Overhead Hardening and Distribution System Protection Modernization measures. Figure 2-4 includes the SRP programs evaluated by 1898 & Co. Section 6.0 includes additional details on this structure for each specific measure.

Figure 2-4: SRP and Resilience Evaluation Overview



This figure shows that the integrated portfolio includes a suite of integrated analytics to identify investments that provide the most benefit for customers. Section 6.0 includes additional details on this structure for each specific measure.

For the Distribution Overhead Hardening and Distribution System Protection Modernization measures, the output of the evaluation is the following:

- avoided reactive and restoration costs;
- avoided customer outages, as measured in CMI; and
- $CMI.

Utilizing the avoided restoration cost, avoided $CMI, and estimated investment level, the evaluation calculates the resilience and risk BCR for each investment activity, program, and substation.

$$Resilience\ \&\ Risk\ BCR = \frac{Lifecycle\ PV\ Avoided\ Restoration\ Costs + Lifecyle\ PV\ Avoided\ \$CMI}{Lifecyle\ Resilience\ Investment}$$

Thus, the BCR as used in this analysis is a single value that represents the complex modeling of resiliency events, infrastructure vulnerability, infrastructure rebuild costs, and other factors to provide a robust and reliable measure to evaluate individual resiliency investments from a quantified customer-benefit perspective.

The results of this evaluation are measured at differing levels for each of the investment activities. This is further described in Section 6.0, in the corresponding measure "Systematic Approach to Estimate Investment Activities, Cost & Benefits" sections. The Resilience & Risk BCR for each investment activity[20] constitutes a sophisticated multi-factored analysis that will allow SPS to take advantage of execution efficiencies to maximize the value of the SRP to SPS's customers. The Resilience & Risk BCR incorporates the following factors for each investment activity (over 17,500 activities modeled as shown in Table 5-2 below) within each measure:

Resiliency Events

- Range of resiliency events – 20 different event types from NOAA;
- Frequency of those resiliency events – averaging 132 per year from NOAA;
- Location of events by county sections of the SPS system; and
- The expected asset-level probability of failure based on historical outage data and infrastructure vulnerability.

Infrastructure Vulnerability

- Number of assets within each investment activity;
- Age of the assets within each investment activity and their expected lives;
- Known equipment original-design vulnerabilities (*e.g.*, Open Wire Secondary);
- Structural loading of infrastructure;
- Vegetation density around each span of conductor for overhead investments;
- Number of downstream customers for each investment activity;
- Types of customers (residential, small C&I, large C&I, and critical customers[21]) for each investment activity; and

[20] 1898 & Co. identified investment activities at the distribution circuit protection zone level.
[21] As designated by SPS.

- The accessibility of the infrastructure in terms of street access and location within SPS service area (urban, suburban, rural).

Infrastructure Rebuild Costs

- The cost to restore the infrastructure and system for each event type and infrastructure vulnerability.
- The resilience investment needed to mitigate the events including:
  - Number of assets, and
  - Location of the assets (rear lot/front lot and urban, suburban, rural).

Financial Factors

- Discounted cash flow methodology over the lifecycle of the infrastructure in mitigating events over the next 50 years - 2.5% for escalation, 6.5% for discount rate (consistent with the values established in SPS's most recent base-rate proceeding).
- The DOE ICE calculator to evaluate the cost of an outage for the range of customer types and outage durations.

For each investment activity, the Resilience & Risk BCR incorporates all these factors. Additionally, 1898 & Co. has carefully integrated all these factors within each analytics model to estimate benefits objectively, consistently, and precisely for each investment activity.

This approach makes the BCR value a robust and reliable measure to help understand and quantify the justification for weather-based resilience investment activities. This multi-factored benefit metric provides confidence that investments will provide benefits in excess of costs for customers. **Additionally, given the alignment of the factors to the Resiliency Rule (resilience events, system vulnerabilities, avoided utility restoration costs, avoided customer outages, etc.), the BCR is a metric that aligns the investment activity to the Resiliency Rule.** SPS's SRP uses this value to guide resilience investment on SPS's system.

While the Resilience & Risk BCR incorporates many factors, it does not capture all benefit streams. The list above shows that the BCR incorporates most of the objective

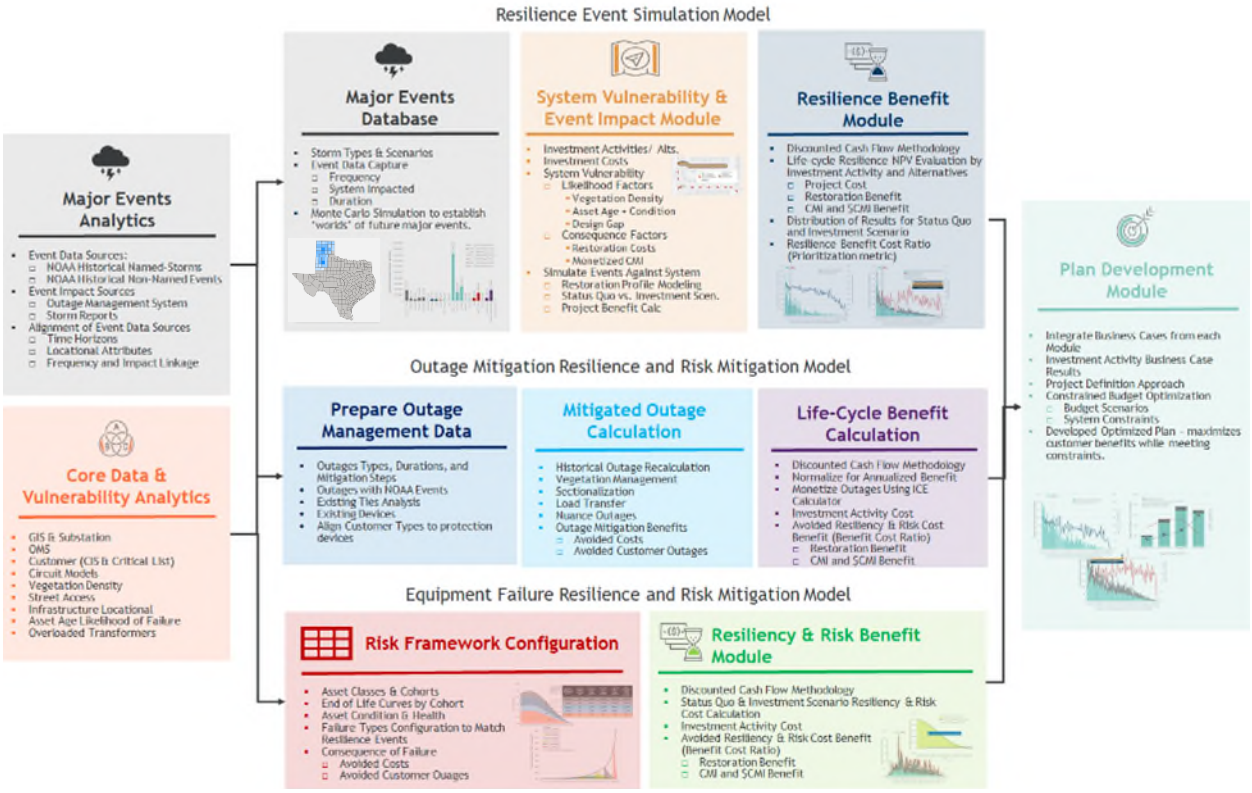
resiliency-related factors within the quantified benefits assessment. 1898 & Co. recognizes that more subjective or difficult-to-quantify risk factors have not been incorporated into this evaluation. Two key subjective factors are safety and areas of lower performance (customers experiencing multiple interruptions). The Resiliency Rule includes prioritizing "areas of lower performance" as a factor for the Commission to consider in determining whether a utility's plan is in the public interest.[22] The Resilience & Risk BCR should be utilized as a key tool in prioritizing and selecting investments, in concert with these qualitative benefit streams. Consideration of the qualitative and quantitative benefit streams together will provide a more complete assessment of the customer benefits associated with each resiliency measure.

2.4.2 Integrated Resilience & Risk Investment Model Overview

The Integrated Resilience & Risk Investment Model employs a data-driven decision-making methodology using robust and sophisticated algorithms to calculate the resilience and risk benefits for each potential investment activity that makes up each measure. Figure 2-5 provides an overview of the Integrated Resilience & Risk Investment Model.

[22] 16 TAC § 25.62(d)(4)(A) and (d)(4)(C)(i)(III).

Figure 2-5: Integrated Resilience & Risk Investment Model



The model first includes foundational data, including the historical resiliency events that impacted the SPS system, data from SPS's OMS, and SPS's asset register and equipment characteristics, which are used to determine the unique vulnerabilities of SPS's system. This information feeds the rest of the model.

Further, the model includes three analytics models (Resilience Event Simulation Model, Outage Mitigation Resilience and Risk Mitigation Model, and Equipment Failure Resilience and Risk Mitigation Model). Each of these analytics models estimates the expected avoided costs (including resilience event costs) and avoided customer outages (including resilience event outages). Each analytics model is designed to estimate the resilience and risk benefits of different resiliency investments based on the available data, asset types, benefit streams, and failure types. Each analytics model provides a direct link between historical resiliency events and specific outages on SPS's system, with sufficient detail to estimate how future resiliency events will impact the system under different investment scenarios. Said another way, these models allow for a quantitative analysis of how SPS's system responded to a historical

resiliency event and how that same system would have responded had certain resiliency measures been in place. This is further discussed in Section 4.0. This allows 1898 & Co. to demonstrate objectively how investment in a particular resiliency measure can improve the system's ability to prevent, withstand, mitigate, or more promptly recover from an event.

Finally, the model includes a plan development module that integrates the quantified benefit-cost results from each of the analytics models, normalizes to avoid double-counting benefits, and captures bundling approaches associated with SPS's systematic implementation approach. For example, if both distribution automation and overhead hardening are implemented, the distribution automation reduces the impact of a failure on the overhead distribution feeder. The normalization takes this into account by reducing the overhead hardening investment benefit as compared to an alternative where only overhead hardening was performed, as a larger number of customers are impacted by a failure. This provides a prioritized list of resilience investment activities for SPS to develop an executable plan that balances maximizing customer benefits against execution constraints for each of the measure programs.

The next three sections of the report provide further detail on each of the core modules that make up the Integrated Resilience & Risk Investment Model. Section 3.0 covers the Major Events Analytics. Section 4.0 covers the three analytics models that estimate the quantified benefits for each resiliency investment activity. Section 5.0 includes additional details of the core data and vulnerability analytics that feed the three analytics models.

3.0 Major Events Impacting SPS's System

16 TAC § 25.62(c)(2)(B)
A resiliency plan must define, identify, and describe each type of resiliency event and any associated resiliency-related risks the plan is designed to prevent, withstand, mitigate, or more promptly recover from.

This section reviews the major historical weather-based resiliency events that impacted SPS's distribution service area and customers. It includes a review of the range of resiliency events that impacted the SPS distribution system going back over 25 years, as documented by NOAA. This information serves as the basis to understand the customer impact of each resiliency event and the expected frequency of similar resiliency events in the future. This section also includes the results of analysis performed by 1898 & Co. correlating the NOAA event database with SPS's historical outage records. Finally, this section prioritizes the resilience risk for each event type.

3.1 NOAA Events

16 TAC § 25.62(c)(2)(B)(i)
A resiliency plan must define, identify, and describe each type of resiliency event and any associated resiliency-related risks the plan is designed to prevent, withstand, mitigate, or more promptly recover from.

NOAA hosts a database of weather-based events across the entire United States. The database includes both named events (e.g., hurricanes) and non-named events (e.g., thunderstorms and ice storms). The named event database includes events and their paths going back over 170 years, beginning in 1852. The non-named event database includes non-named events (e.g., thunderstorms and ice storms) going back over 25 years, beginning in 1998. 1898 & Co. utilized this non-named events database for SPS.

This database helped identify the types of resiliency events that impact the SPS service area as well as the expected frequency of different resiliency events. Given the breadth of SPS's service area, resiliency events that impact one part of the service area may not impact another. The NOAA database is useful in understanding these differences.

The NOAA database records events at the county or sub-county level. 1898 & Co. mined this data for all counties within SPS's service area. The database includes the following types of weather-based events and their definitions from NOAA:

Table 3-1: Extreme Weather Resiliency Events[23]

No.	Resiliency Event Type	Resiliency Event	Definition
1	Wind	Thunderstorm Wind	Winds, arising from convection (occurring within 30 minutes of lightning being observed or detected), with speeds of at least 50 knots (58 mph), or winds of any speed (non-severe thunderstorm winds below 50 knots) producing a fatality, injury, or damage.
2		Lightning	A sudden electrical discharge from a thunderstorm, resulting in a fatality, injury, and/or damage.
3		Hail-Wind	Hail is defined as, Frozen precipitation in the form of balls or irregular lumps of ice. Hail of any size may be reported, in hundredths of an inch, although the smallest measure in the hail conversion table is 0.25 inches. This report uses "Hail-Wind" to refer to hail that occurs not in connection with a winter-weather event and not during the months of December, January, and February.
4		High Wind	Sustained non-convective winds of 35 knots (40 mph) or greater lasting for 1 hour or longer, or gusts of 50 knots (58 mph) or greater for any duration (or otherwise locally/regionally defined).
5		Strong Wind	Non-convective winds gusting less than 50 knots (58 mph), or sustained winds less than 35 knots (40 mph), resulting in a fatality, injury, or damage.
6	Flood	Flood	Any high flow, overflow, or inundation by water which causes damage.
7		Heavy Rain	Unusually large amount of rain which does not cause a Flash Flood or Flood event, but causes damage, e.g., roof collapse or other human/economic impact.
8		Flash Flood	A life-threatening, rapid rise of water into a normally dry area beginning within minutes to multiple hours of the causative event (e.g., intense rainfall, dam failure, ice jam). Six inches or more of swiftly moving water flowing over a road or bridge, posing a threat to life or property is one of many suggested guidelines for determining if an event was a Flash Flood.
9	Tornado	Tornado	A violently rotating column of air, extending to or from a cumuliform cloud or underneath a cumuliform cloud, to the ground, and often (but not always) visible as a condensation funnel.

[23] NWSI 10-1605, Storm Data Preparation (noaa.gov)

No.	Resiliency Event Type	Resiliency Event	Definition
10	Winter	Winter Weather	A winter precipitation event that causes a death, injury, or a significant impact to commerce or transportation, but does not meet locally/regionally defined warning criteria. A Winter Weather event could result from one or more winter precipitation types (snow, or blowing/drifting snow, or freezing rain/drizzle).
11		Sleet	Sleet accumulations meeting or exceeding locally/regionally defined warning criteria (typical value is ½ inch or more). Per the National Weather Service, the Southern Region weather criteria for sleet in the State of Texas is ½ inch or more.
12		Winter Storm	A winter weather event that has more than one significant hazard (i.e., heavy snow and blowing snow; snow and ice; snow and sleet; sleet and ice; or snow, sleet and ice) and meets or exceeds locally/regionally defined 12 and/or 24-hour warning criteria for at least one of the precipitation elements.
13		Heavy Snow	Snow accumulation meeting or exceeding locally/regionally defined 12 and/or 24 hour warning criteria. This could mean values such as 4, 6, or 8 inches or more in less than 12 hours or less; or 6, 8, or 10 inches in 24 hours or less. Heavy snow criteria range from 1 inch per event in the southernmost portions of Texas to 4 inches in 12 hours and 6 inches in 24 hours in the northernmost portions.
14		Ice Storm	Ice accretion meeting or exceeding locally/regionally defined warning criteria (typical value is ¼ or ½ inch or more)." The ice accumulation criteria for the southern portion of Texas is 1/8 or more, while the criteria is ¼ inch or more throughout the remainder of the state.
15		Hail-Winter	Hail is defined as, Frozen precipitation in the form of balls or irregular lumps of ice. Hail of any size may be reported, in hundredths of an inch, although the smallest measure in the hail conversion table is 0.25 inches. This report uses "Hail-Winter" to refer to hail that occurs in connection with a winter-weather event, and/or during the months of December, January, and February.
16		Blizzard	A winter storm which produces the following conditions for three (3) consecutive hours or longer: (1) sustained winds or frequent gusts of 30 knots (35 mph) or greater, and (2) falling and/or blowing snow reducing visibility frequently to less than ¼ mile.
17	Heat	Heat	A period of heat resulting from the combination of high temperatures (above normal) and relative humidity. A Heat event occurs and is reported in Storm Data whenever heat index values meet or exceed locally/regionally established advisory thresholds. Heat advisory thresholds range from heat index/temperature levels of 100°F and above to heat index/temperature levels of 110°F and above in Texas.
18		Excessive Heat	Excessive Heat results from a combination of high temperatures (well above normal) and high humidity. An Excessive Heat event occurs and is reported in Storm Data whenever heat index values exceed locally/regionally established excessive heat warning thresholds. Excessive heat warning thresholds range from heat index/temperature levels of 105°F and above to heat index/temperature levels of 115°F and above in Texas.

No.	Resiliency Event Type	Resiliency Event	Definition
19	Cold	Cold/Wind Chill	Period of low temperatures or wind chill temperatures reaching or exceeding locally/regionally defined advisory (typical value is -18°F or colder) conditions.
20		Extreme Cold/Wind Chill	A period of extremely low temperatures or wind chill temperatures reaching or exceeding locally/regionally defined warning criteria (typical value around -35°F or colder).

Drought was excluded from the analysis since its durations are extremely long, making the outage correlation challenging with any degree of certainty. Additionally, wildfire is not covered in the 1898 & Co. report.

Figure 3-1 includes the summary results from the NOAA database of extreme weather events that hit the SPS service area from 1998 to 2023. Data for 2024 is currently not available. This figure includes 20 different events across 5 categories (excluding wildfire and drought, as mentioned above), showing the wide diversity of events that impact SPS's customers. A total of 3,443 weather-based resiliency events have impacted the SPS service area since 1998, averaging 132.4 events per year. The most common event category is wind-based with Thunderstorm Wind accounting for 1,226 events. This information serves as the basis for estimating the future frequency of resiliency events to impact SPS service area and customers.

Figure 3-1: Extreme Weather Events in SPS Service Area since 1998[24]

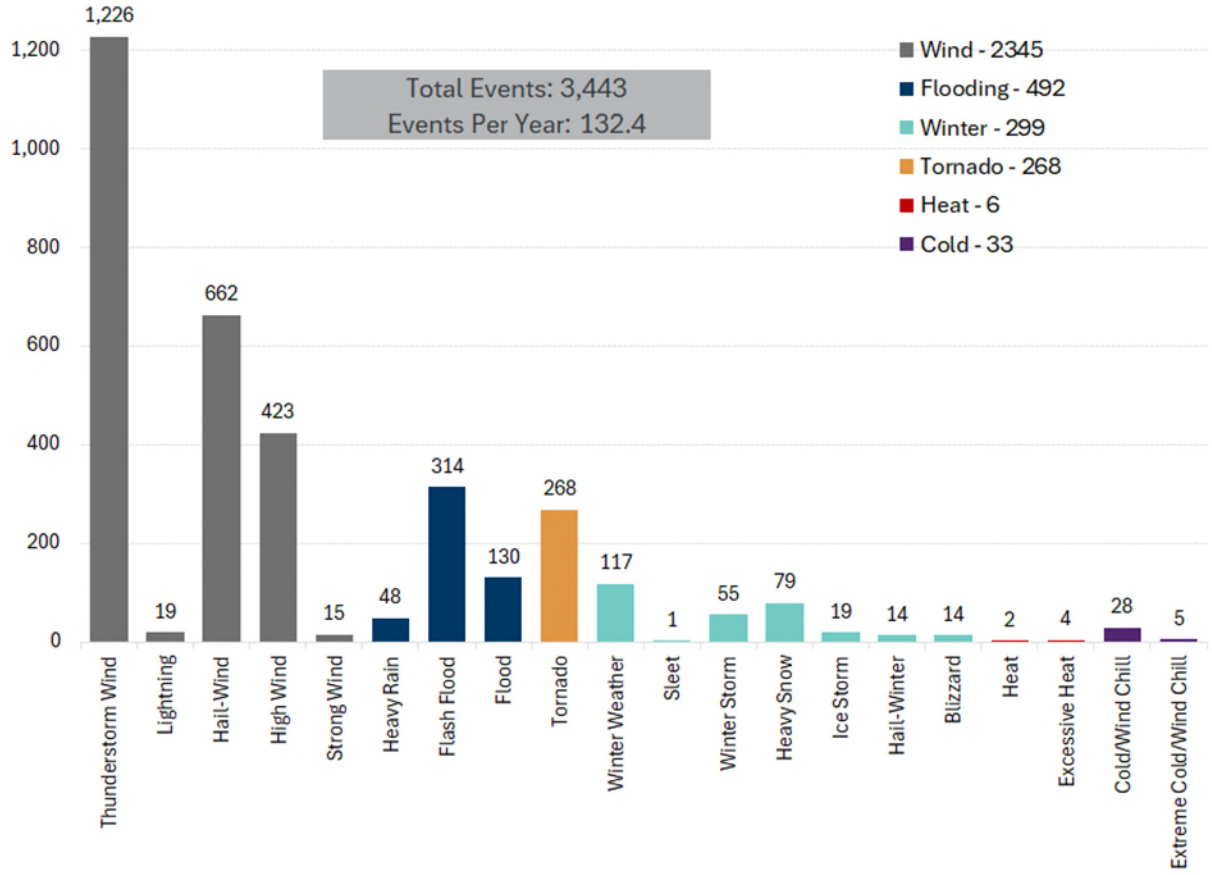
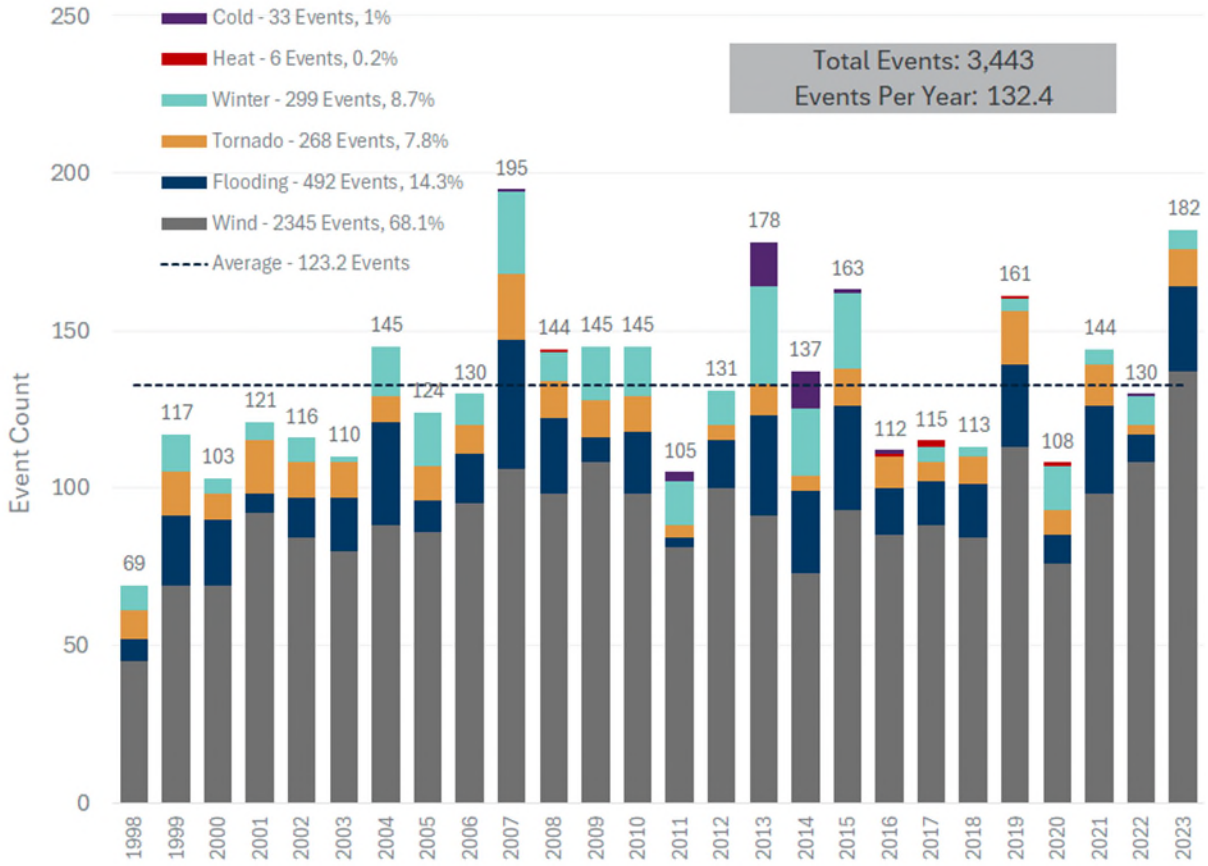


Figure 3-2 shows the resiliency event count for SPS's service area beginning in 1998, broken down by event type for all 3,443 events. This figure shows a wide range of events occur year to year with 1998 having a low of 69 events, while 2007 had 195, nearly triple 1998. Wind-type events account for the highest percentage of events that impact the SPS service area at 68.1% of the total event count.

[24] Source: https://www.ncdc.noaa.gov/stormevents/ with analysis by 1898 & Co.

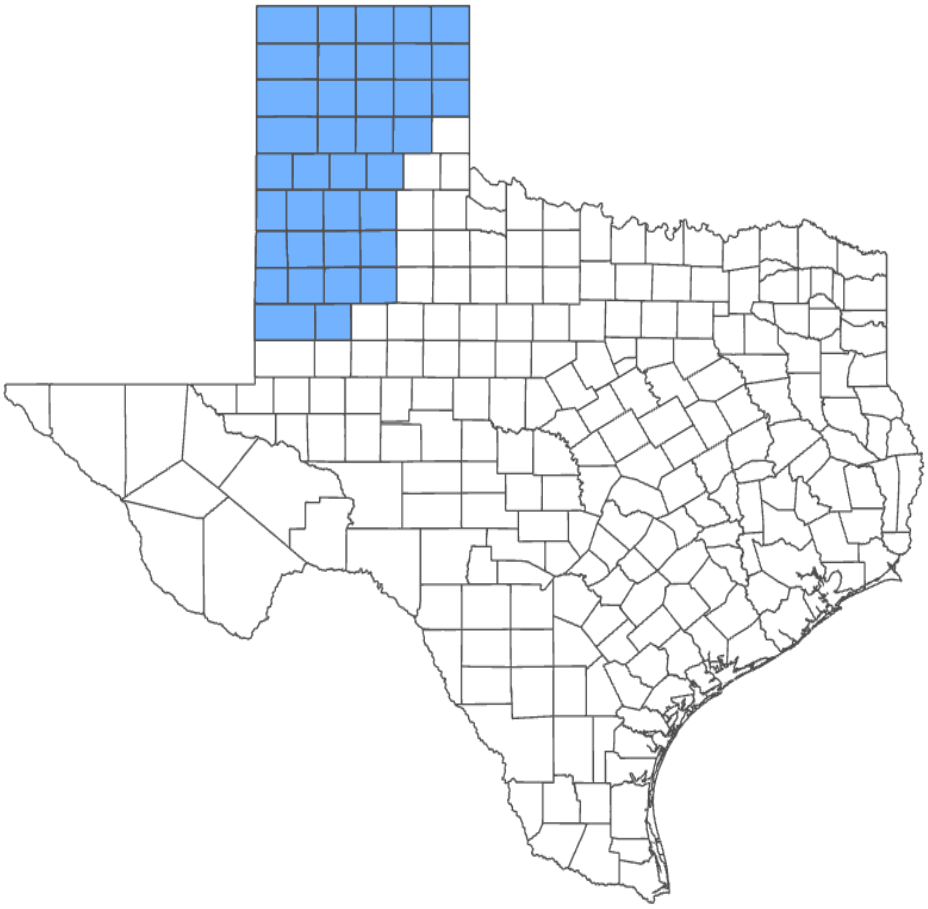
Figure 3-2: Count of Events for SPS's System by Year[25]



1898 & Co. utilized NOAA data that organizes the historical events by county across SPS's service area to understand the locational differences of the weather-based events. Figure 3-3 provides an overview of the counties that intersect across SPS's service area. It is at this level that 1898 & Co. captured each resiliency event.

[25] Source: https://www.ncdc.noaa.gov/stormevents/ with analysis by 1898 & Co.

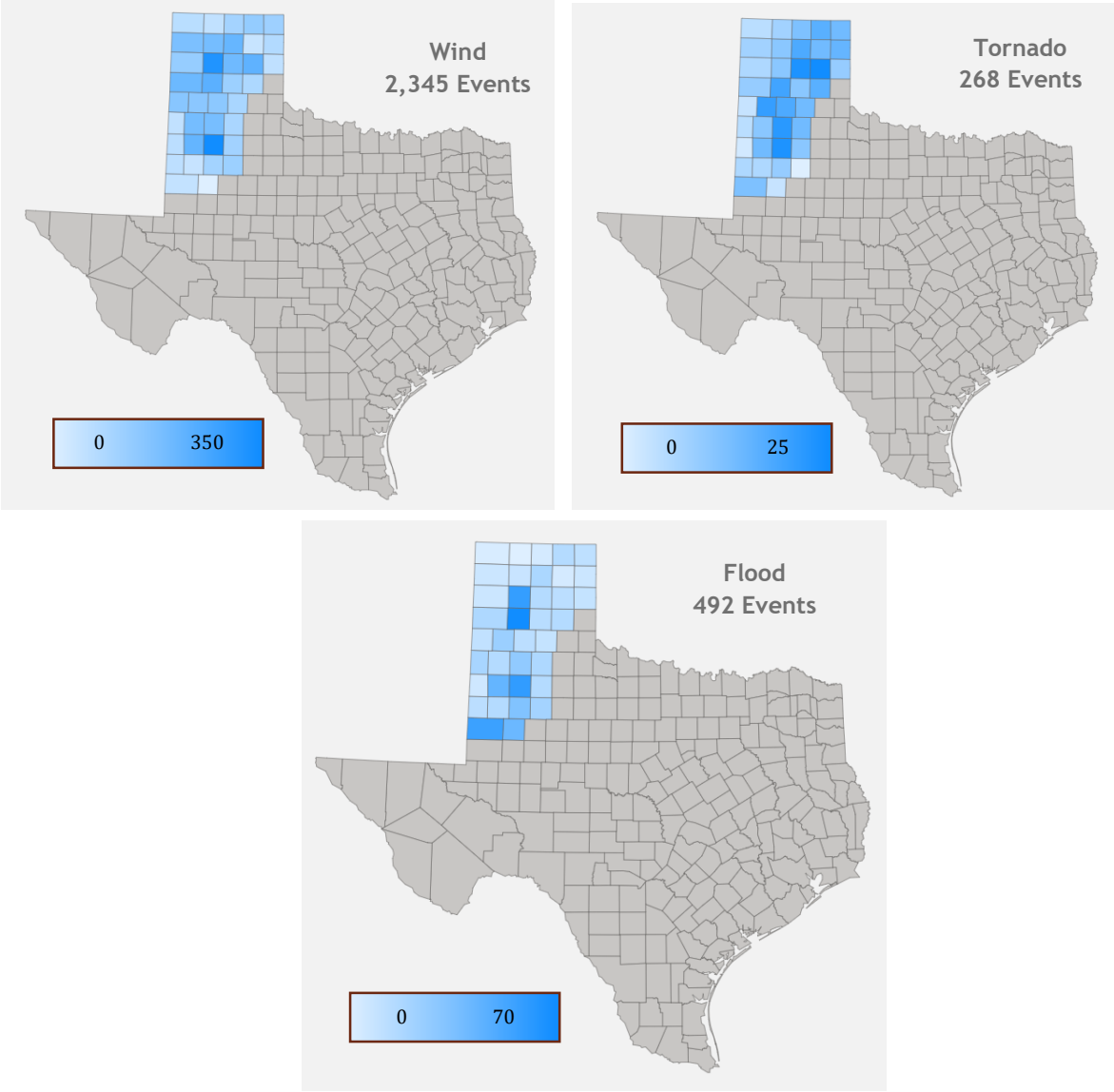
Figure 3-3: SPS Service Area County Locations



The map above is helpful to understand how this wide range of resiliency events impact the large geographical service area of SPS. The following set of figures provide insights into where the different types of extreme weather resiliency events impact SPS's customers. Figure 3-4 provides a "heat map" of weather-related events for all NOAA Extreme Weather events from 1998 – 2023 in the wind, flooding, and tornado categories. Figure 3-5 shows the "heat map" of events for the winter, heat, and cold categories. Analysis of these figures and the ones above show:

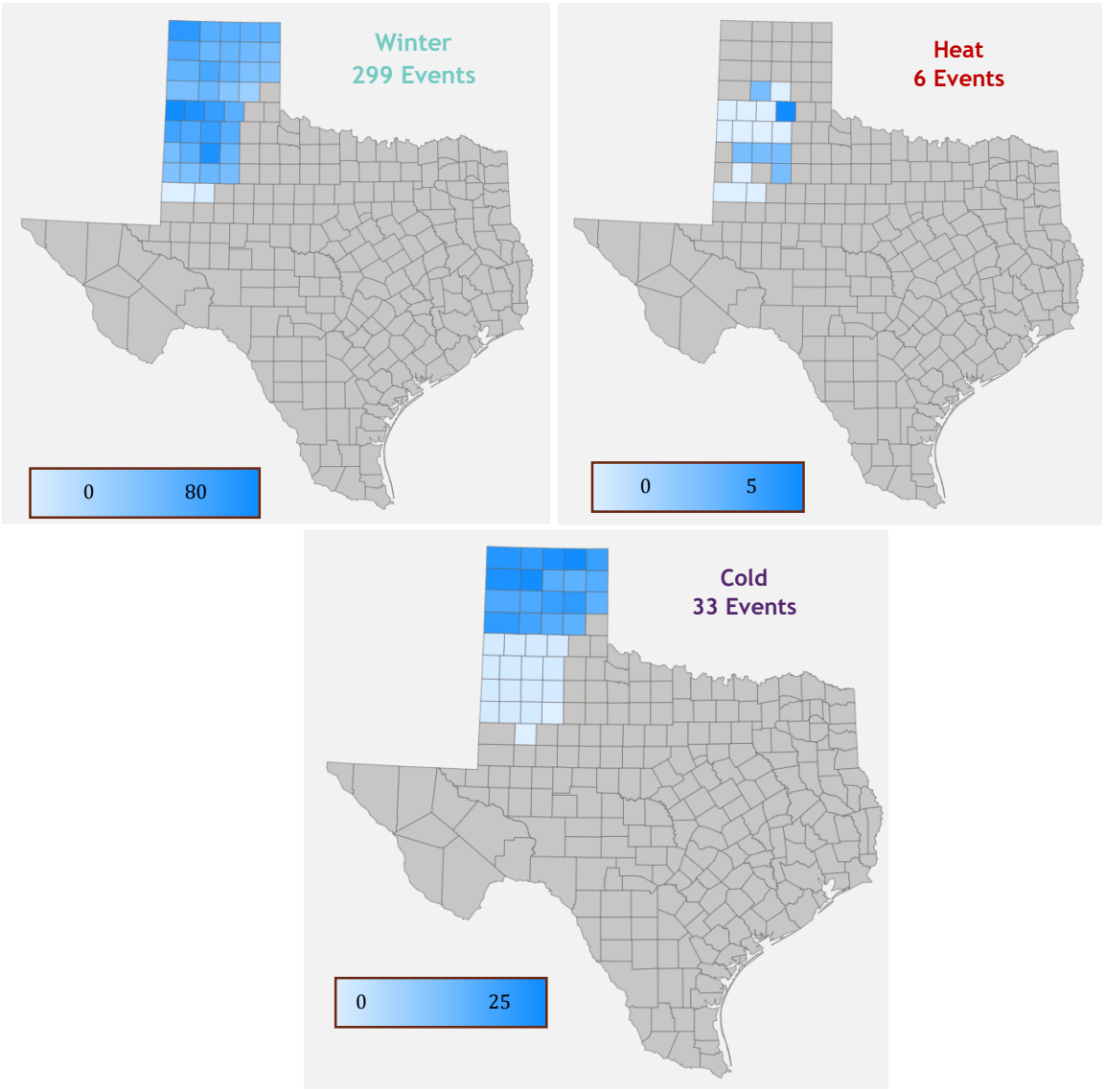
- **The number of events varies significantly** across SPS's service area.
- **The profile of resiliency-event types also varies significantly** across each section, demonstrating the challenge before SPS in building and maintaining a resilient system.

Figure 3-4: Relative Events Count "Heat Map" (Wind, Flood, Tornado) [26]



[26] Source: https://www.ncdc.noaa.gov/stormevents/ with analysis by 1898 & Co.

Figure 3-5: Relative Events Count "Heat Map" (Winter, Heat, Cold)[27]



3.2 NOAA Events and Outage Records

16 TAC § 25.62(c)(2)(B)(iv)
A resiliency plan must provide sufficient evidence to support the presence of and risk posed by each identified resiliency event.

The previous section provided foundational information to understand the range of resiliency-event types that impact the SPS service area, where those resiliency events tend to occur within the SPS service area, and the number of resiliency events, which

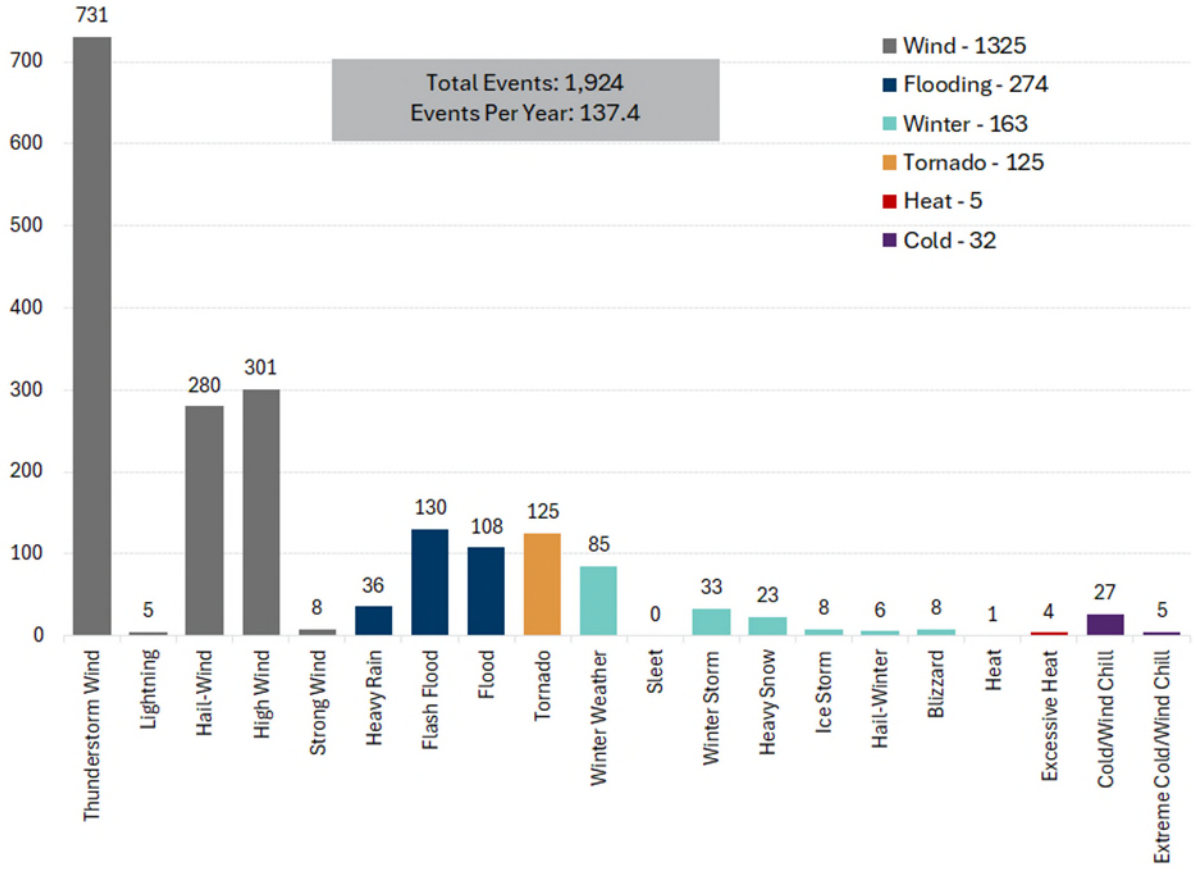
[27] Source: https://www.ncdc.noaa.gov/stormevents/ with analysis by 1898 & Co.

provides insights into resiliency-event frequency. This section assesses the impact of these events. To perform that assessment, 1898 & Co. performed a correlation analysis between the NOAA event data and SPS's historical outage records. As noted above, this evaluation excludes wildfire and drought events. For the period of 2010 through 2023, 1898 & Co. correlated each event in NOAA to SPS's outage records, based on time stamps from both data sets. 2010 is the earliest year for which data is available for SPS's historical outage records within the OMS, and 2023 is the latest year for which NOAA event data is available. This correlation allows customer outages to be directly linked to specific resiliency events to assess how the system performed during an individual event.

3.2.1 NOAA Events from 2010-2023

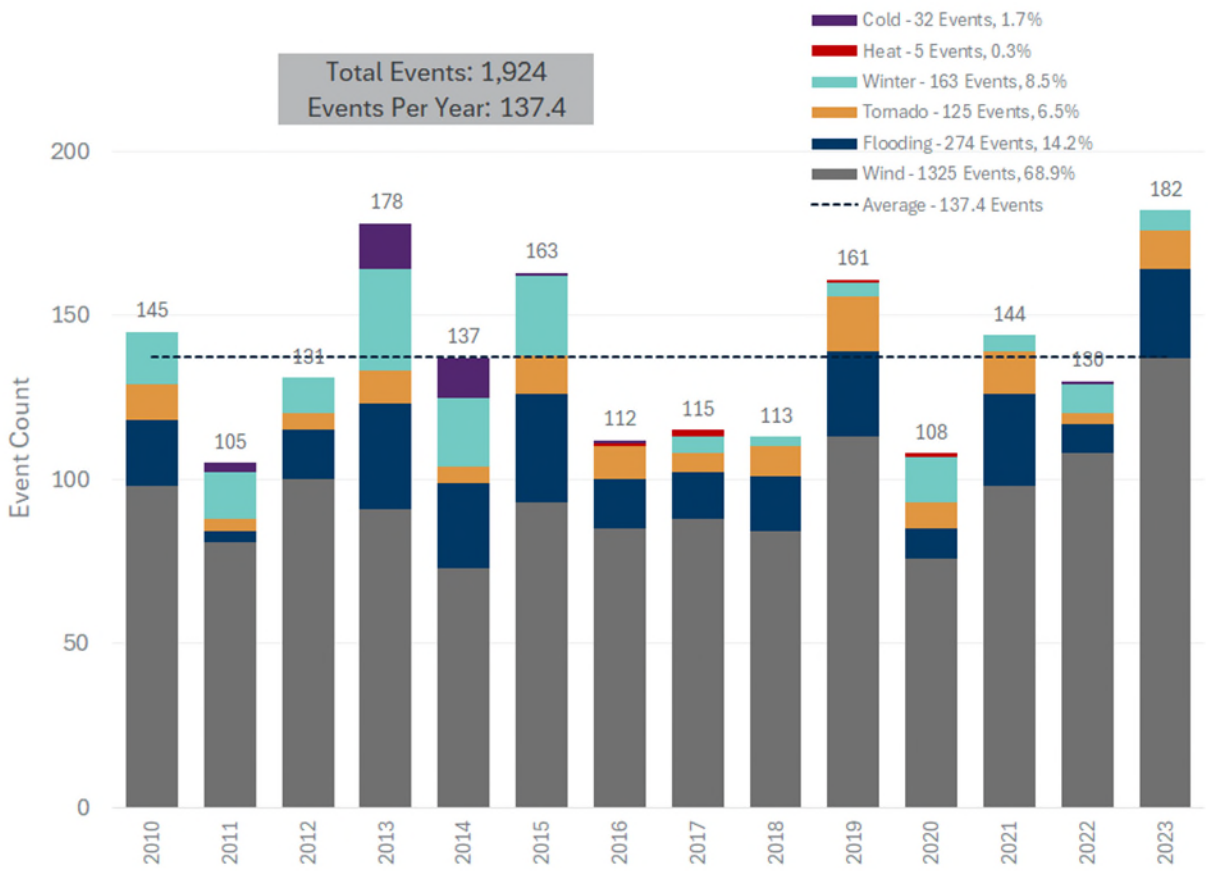
1898 & Co. identified over 1,924 NOAA events where an outage was recorded in SPS's OMS. Figure 3-6 shows the types of events 1898 & Co. mapped to SPS's OMS. Figure 3-7 shows the summary of event types by year.

Figure 3-6: NOAA Events identified in SPS's Outage Records (2010-2023)[28]



[28] Source: https://www.ncdc.noaa.gov/stormevents/ with analysis by 1898 & Co.

Figure 3-7: NOAA Summary Events by Year identified in SPS's Outage Records (2010-2023)[29]



3.2.2 NOAA Events and Customer Minutes Interrupted

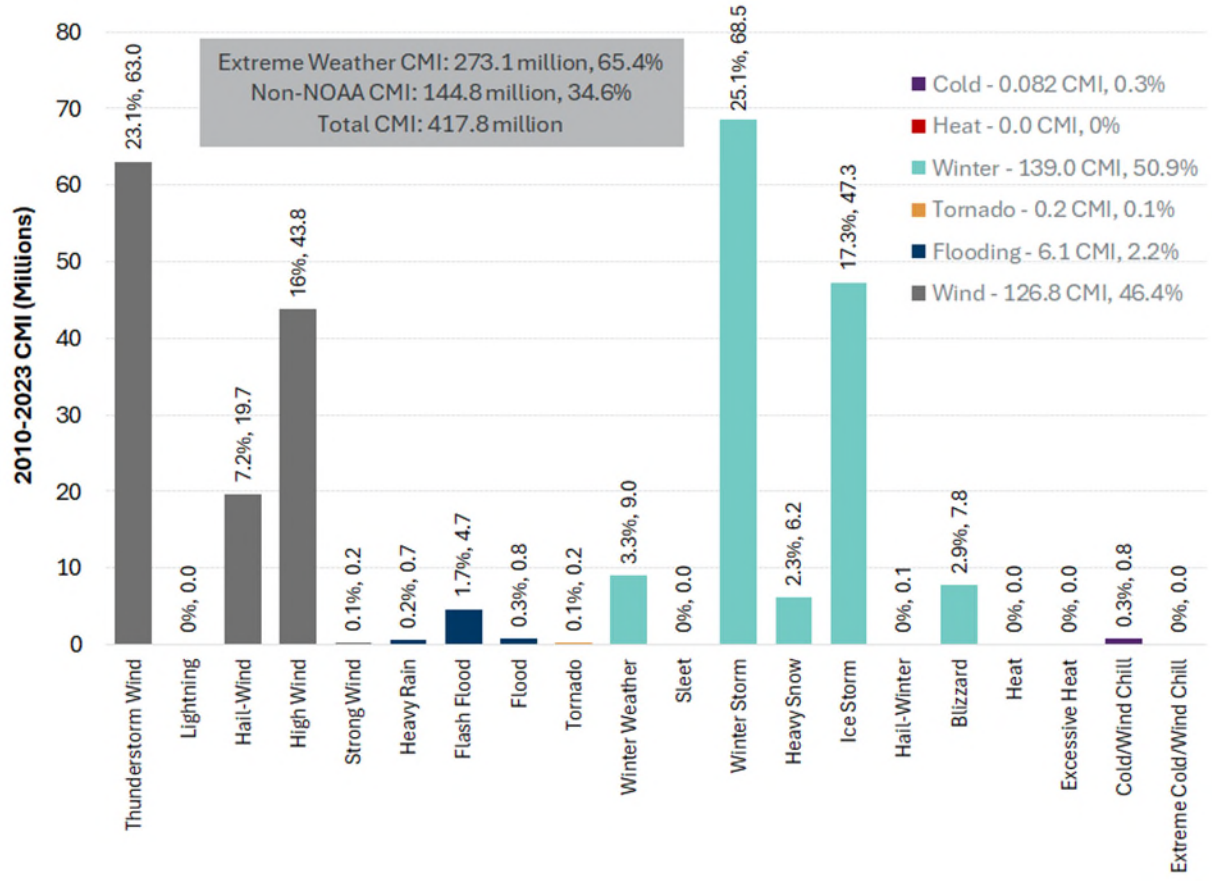
Over the period of from 2010 through 2023, SPS recorded outages of approximately 417.8 million CMI. 1898 & Co. mapped approximately 273.1 million CMI to one of the 1,924 NOAA events. In other words, approximately 65.4% of SPS CMI occurred during the resiliency events recorded by NOAA, and the remaining 34.6%, or 144.8 million CMI, occurred during "blue-sky" reliability days. This relatively high percentage is likely due to the low vegetation density across the system, causing fewer outages when resiliency events are not occurring. Approximately 99% of the SPS system's protection zones have an average vegetation density of 20% or less (see Section 5.7 for additional details). **This shows the significant contributions of major weather**

[29] Source https://www.ncdc.noaa.gov/stormevents/ with analysis by 1898 & Co.

events to customer outages and the need for resilience investment to mitigate these impacts.

SPS's system outages are heavily driven by NOAA weather events. This correlation demonstrates the substantial benefit SPS's customers stand to gain through resiliency investment in the system. For the 65.4% of all outages that occurred during a NOAA event, Figure 3-8 shows the mapped CMI for each of the event types over the 2010-to-2023-time horizon.

Figure 3-8: Mapped CMI to NOAA Events (2010-2023)[30]



The figure shows the following:

- A handful of event types account for most of the mapped CMI. Specifically, 4 event types account for over 81% of all CMI-mapped NOAA events and 53.3% of

[30] Source: https://www.ncdc.noaa.gov/stormevents/ and SPS's OMS with analysis by 1898 & Co.

all outages. Each of these event types accounts for more than 10% of all outages.

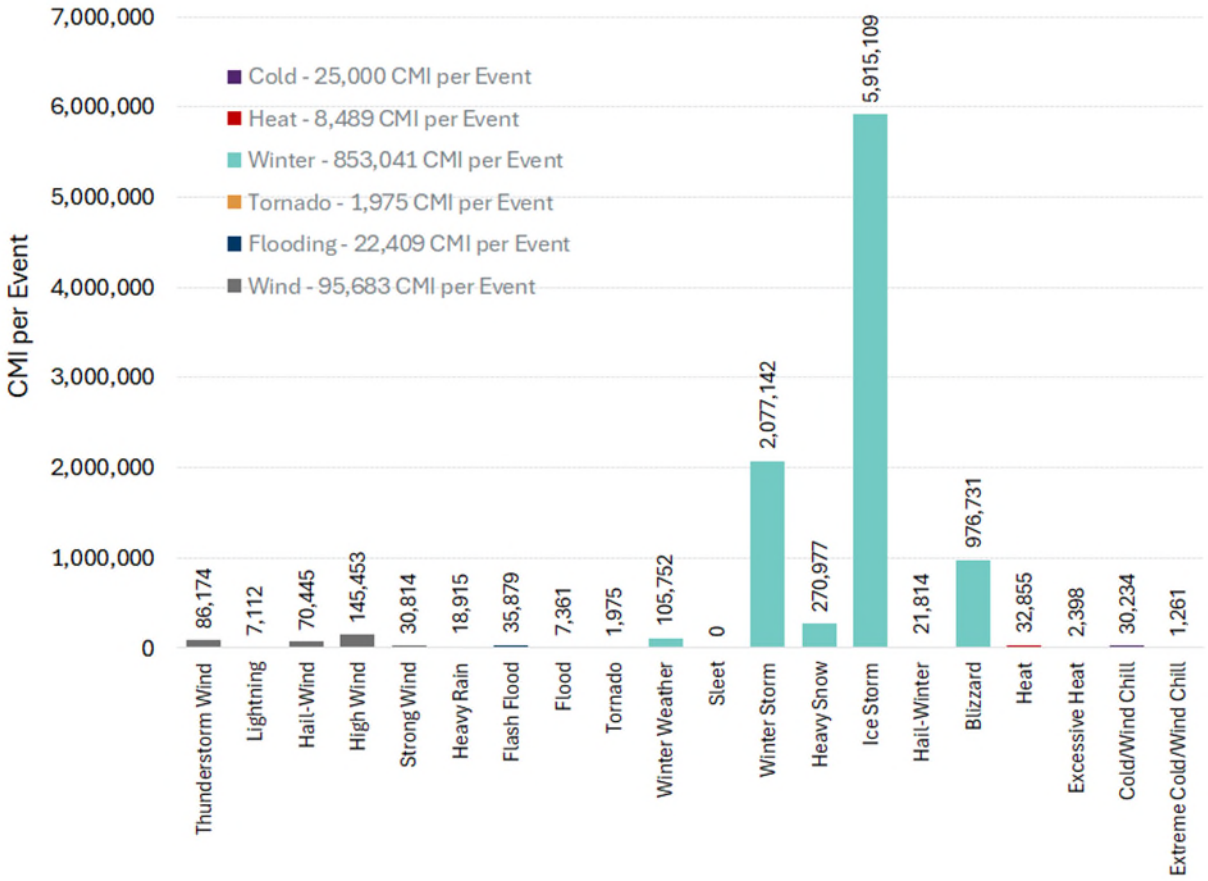
- The Winter Storm NOAA event has the highest number of CMI-mapped NOAA events at 25.1%, and 16.4% of all outages.
- The Thunderstorm Wind NOAA event has the second highest number of CMI-mapped NOAA events at 23.1%, and 15.1% of all outages.
- The Ice Storm NOAA event has the third highest number of CMI-mapped NOAA events at 17.3%, and 11.3% of all outages.
- The High Wind NOAA event has the fourth highest number of CMI-mapped NOAA events at 16.0%, and 10.5% of all outages.

- 5 of the 20 event types account for 1 to 5% each of the mapped NOAA CMI. These five event types are Hail-Wind, Flash Flood, Winter Weather, Heavy Snow, and Blizzard. Together, they account for 17.4% of all NOAA mapped outages, and 11.3% of all outages.
- 11 of the 20 event types account for less than 1% each of all NOAA mapped outages. These 11 event types collectively account for 1.1% of all NOAA mapped outages, and 0.7% of all outages.

3.2.3 Customer Minutes Interrupted per Event

Figure 3-9 shows the historical average CMI per event for each event type. These results are derived by taking the CMI from Figure 3-8 and dividing by the number of events from Figure 3-6. These values serve as the basis to understand the consequence of individual events on the system.

Figure 3-9: CMI Per Event[31]



3.3 Event Prioritization Summary

16 TAC § 25.62(c)(2)(A)(i)
The resiliency plan must explain the electric utility's prioritization of the identified resiliency event and, if applicable, the prioritization of the particular geographic area, system, or facilities where the measure will be implemented.

Table 3-2 provides a prioritization of the resiliency events evaluated by 1898 & Co. that impacted SPS customers. The table includes the events discussed in Section 3.2 above. Table 3-2 prioritizes the quantified event types based on their expected annual average CMI. This value is the average number of events per year, the frequency, multiplied by the CMI per event, the impact. The average number of events per year is from the 1998 to 2023 period based on the NOAA data, as shown in Figure 3-7 above. The CMI per event is from Figure 3-9 above. The table also includes

[31] Source: https://www.ncdc.noaa.gov/stormevents/ and SPS's OMS with analysis by 1898 & Co.

the relative ranking of the event frequency and impact. The information in Table 3-2 is the core event data utilized within the Integrated Resilience & Risk Investment Model to estimate the quantified benefits of resilience investments across the system. This is discussed in the next section.

Table 3-2: Prioritization of Resiliency Events

	Event Category	Event Type	1998 - 2023 Avg Events / Year	CMI Per Event	Annual Average CMI	Event Frequency Rank	Event Impact Rank
1	Winter	Winter Storm	2.12	2,077,142	4,393,954	9	2
2	Winter	Ice Storm	0.73	5,915,109	4,322,580	12	1
3	Wind	Thunderstorm Wind	47.15	86,174	4,063,436	1	7
4	Wind	High Wind	16.27	145,453	2,366,409	3	5
5	Wind	Hail-Wind	25.46	70,445	1,793,630	2	8
6	Winter	Heavy Snow	3.04	270,977	823,354	8	4
7	Winter	Blizzard	0.54	976,731	525,932	15	3
8	Winter	Winter Weather	4.50	105,752	475,882	7	6
9	Flooding	Flash Flood	12.08	35,879	433,306	4	9
10	Flooding	Flood	5.00	7,361	36,805	6	15
11	Flooding	Heavy Rain	1.85	18,915	34,920	10	14
12	Cold	Cold/Wind Chill	1.08	30,234	32,559	11	12
13	Tornado	Tornado	10.31	1,975	20,362	5	18
14	Wind	Strong Wind	0.58	30,814	17,777	14	11
15	Winter	Hail-Winter	0.54	21,814	11,746	15	13
16	Wind	Lightning	0.73	7,112	5,197	12	16
17	Heat	Heat	0.08	32,855	2,527	19	10
18	Heat	Excessive Heat	0.15	2,398	369	18	17
19	Cold	Extreme Cold/Wind Chill	0.19	1,261	243	17	19
20	Winter	Sleet	0.04	0	0	20	20

The table shows the following:

- The various categories of winter and wind events account for the top 8 event types impacting SPS customers. These 8 event types account for 97% of the annual average customer outages.
- The first three events, Winter Storm, Ice Storm, and Thunderstorm Wind, have similar annual average CMI at just over 4 million a year. These three events impact customers approximately the same account on an annual average basis, however, both of the winter category events are lower-frequency high-impact event types while Thunderstorm Wind is a high-frequency lower-impact type of

events. The two winter events rank number 1 and 2 in terms of CMI per event, but 9th and 12th in terms of frequency. So while these events are less common, when they do happen the impact to customers is significant. The Thunderstorm Wind event has the highest annual frequency, with over 47 events per year and ranking 7th in terms of customer outages per event. The significant differences in frequency and impacts but similar annual customer impacts demonstrate a significant challenge in selecting resiliency investments to manage the weather-based resiliency risk.

- High Wind and Hail-Wind events are the 4th and 5th ranked events. From an annual average CMI perspective, these two events are approximately half as impactful as the first three ranked events. Both of these events have a relatively high frequency, ranking 2nd and 3rd, but lower CMI per event at 5th and 8th.
- Temperate based events, hot and cold, are relatively less impactful by a factor of 10 to 20 times that of the major winter and wind-based events.

The information in Table 3-2 is the core event data utilized within the Integrated Resilience & Risk Investment Model to estimate the quantified benefits of resilience investments across the system. This is discussed in the next section.

4.0 Resilience and Risk-Based Planning Approach

16 TAC § 25.62(c)(2)(E)
A resiliency plan must be implemented using a systematic approach over a period of at least three years. The resiliency plan must explain this systematic approach and provide implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments. The resiliency plan should identify relevant cost drivers (e.g., line miles, frequency of inspections, frequency of trim cycles, etc.) that would affect the estimates.

1898 & Co. utilized a resilience and risk-based planning approach to identify, prioritize, and perform a benefit-cost analysis to support the development of SPS's SRP. The resilience and risk-based planning approach utilizes a suite of planning models, as well as the Integrated Resilience & Risk Investment Model developed by 1898 & Co. The Integrated Resilience & Risk Investment Model (also referred to as the "model") leverages the Conceptual Resilience Framework outlined in Section 2.2. The model takes the "theory" of the measures and develops an actionable investment plan that prioritizes resilience and risk-based investments based on available data, analytics models, and a benefit-cost analysis.

The Resilience and Risk-Based Planning Approach quantifies the resilience and risk improvements at the investment activity, program, circuit, and measure levels. This allows for the analysis of expected system resiliency improvement based on investment or implementation of a specific resiliency measure. For the purposes of this evaluation, resilience and risk benefits for investment activities are estimated from a customer-centric perspective that aligns with the Resiliency Rule.[32] The customer benefits are shown in terms of the:

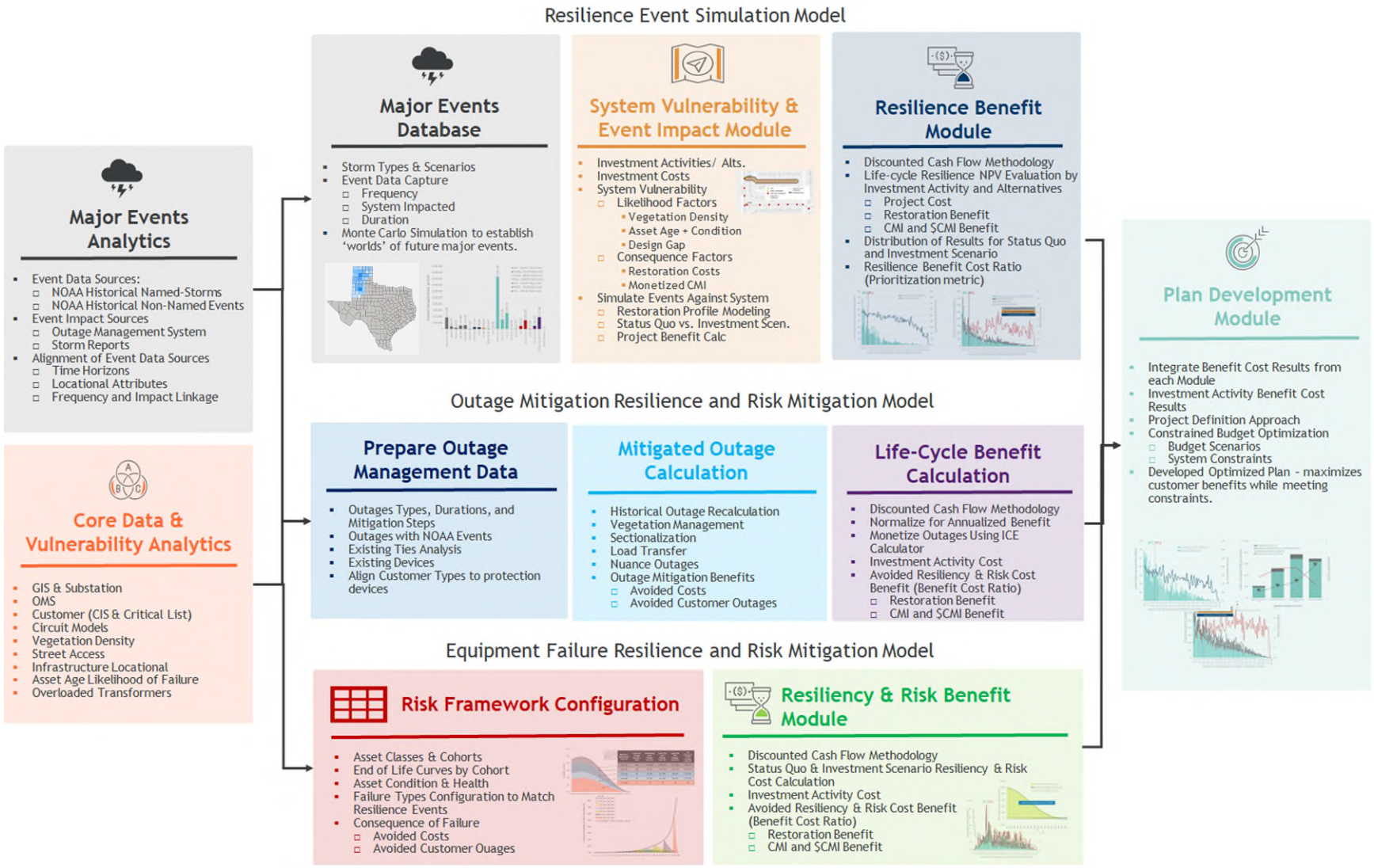
[32] 16 TAC § 25.62(c)(2)(A)(iii).

1. Decrease in the system restoration costs; and the
2. Decrease in the number of customers impacted and in the duration of the overall outage, calculated as CMI and $CMI.

The Integrated Resilience & Risk Investment Model employs a data-driven, decision-making methodology using robust and sophisticated algorithms to calculate the resilience and risk benefits for each potential investment activity that makes up each measure. Figure 4-1 provides an overview of the Integrated Resilience & Risk Investment Model.

Section 5.0 provides additional information on the foundational data resiliency events, and infrastructure vulnerability. The next three sub-sections provide additional detail on each of the analytics models that estimate benefits.

Figure 4-1: Integrated Resilience & Risk Investment Model



The resilience net benefit calculation utilizes a discounted cashflow model and includes the following economic assumptions:

- Period: 50 years – Most of the hardening infrastructure will have an average service life of 50 or more years;
- Escalation Rate: 2.5%; and
- Discount Rate: 6.5%.

4.1 Resilience Event Simulation Approach

Figure 4-2 provides an overview of the Resilience Event Simulation Model that is used to calculate the restoration cost reduction and CMI reduction of resilience investment activities.

Figure 4-2: Resilience Event Simulation Model



4.1.1 Major Events Database

Since the magnitude of the decrease in restoration costs and CMI depends on the frequency and magnitude of future major events that may impact the SPS service area, the Resilience Event Simulation Model starts with the "universe" of major weather events that could impact SPS's service area. The Major Event Database provides a high-level impact to the system for each of the NOAA defined storm stressors. The major events database includes the following inputs:

- Event Type;

- Frequency of an event occurring for each County section of SPS's service area;
- Percentage of the system impacted;
  - Backbone Protection Devices; and
  - Lateral Protection Devices;
- Duration of the event; and
- Restoration Costs.

In developing the database, 1898 & Co. utilized historical event information from NOAA's non-named storm database (26 years of historical data), and SPS's historical outage records (14 years of data) to ascertain the frequency and impact of events, as outlined in Section 3.0.

4.1.2 System Vulnerability & Event Impact Module

The System Vulnerability & Impact Module develops a list of potential resilience investment activities, their costs, and their mitigation effectiveness. The evaluation is comprehensive in evaluating nearly the entire distribution system and different hardening alternatives, mainly overhead hardening rebuilds and an undergrounding alternative. Hardening investments and their alternatives are defined and evaluated at the protection zone level for distribution circuits. The module also estimates the costs for each of the resilience investment activities.

The module models the impact to the system of any type of major storm event. Specifically, it identifies, from a probability-weighted perspective, each protection zone's likelihood to fail for each type of storm in the Major Events Database. The probability-weighting is based on asset age and other condition information, vegetation density, and asset counts within the protection zone. This aligns with the main driver of failures during storms, wind blowing vegetation (and other debris) into the conductor, putting stress on the assets. The additional stress causes the structures holding up the conductor to fail.

The module estimates the restoration costs associated with the specific failures and calculates the impact to customers in terms of CMI. Storm restoration costs were calculated for every asset in the model. The costs were based on storm restoration

cost multipliers above planned replacement costs. The multipliers are based on historical events, expected inventory constraints, and the expected mix of SPS and non-SPS crews needed for the various asset types and storm events. For each storm event, the restoration costs at the asset level are aggregated up to the investment activity level. For the circuit distribution system, potential investment activities are organized at the protection zone level (see Section 5.1).

The module calculates the duration to restore each protection zone in the Status Quo Scenario. The protection zone-specific duration is based on restoration curves for each major asset class. The zones are ranked by criticality based on customer attributes to prioritize storm restoration activity. Specific zone durations are calculated based on storm-specific restoration curves. The zone duration is then multiplied by the number and type of affected customers for each zone to calculate the CMI for each investment activity. The CMI for each protection zone for each storm event is monetized using the DOE ICE values that correspond to the outage duration and customer type(s).

Finally, the module calculates the storm restoration costs and CMI for the 'Status Quo' and Resilience Investment Scenarios for each investment activity and NOAA defined event. The delta between the two scenarios is the benefit for each investment activity. This is calculated for each storm event based on the change to the core assumptions (vegetation density, age, restoration costs, duration, and customers impacted) for each investment activity. The output from the module is a probability-weighted estimate of annual storm restoration costs, annual CMI, and annual $CMI for both the 'Status Quo' and Resilience Investment Scenarios for all NOAA defined events by protection zone /investment activity.

In summary, the System Vulnerability & Event Impact Module utilizes a robust and sophisticated set of data and algorithms to model the benefits of each resilience investment activity for each storm scenario. As each overhead resilience investment activity is defined and evaluated at the protection zone level, it allows for the System Vulnerability & Event Impact Module to reasonably project the ratio of resilience

benefits to the appropriate cost. This provides confidence that investments target the portions of the system that provide the most value for customers.

4.1.3 Resilience Benefit Module

The benefits of resilience investment activities are driven by the frequency, intensity, and location of future storm events over the next 50 years. Each storm type has a range of potential probabilities and consequences. For this reason, the Resilience Benefit Module employs stochastic modeling, specifically, a random sampling methodology called Monte Carlo Simulation.

In the context of the Resilience Event Simulation Model, the Monte Carlo simulator selects the major storm events likely to impact the SPS service area over the next 50 years from the Major Event Database. That database outlines the 'universe' of storm event types that could impact the SPS service area. During the Monte Carlo simulation, each county section is subjected to the probable range of event types and frequencies.

For each future storm simulated, the Monte Carlo simulator determines the benefits that each investment activity provides. Using information from the System Vulnerability & Event Impact Module, the Monte Carlo simulator uses a Status Quo value for each investment activity and the benefits of that investment if it were to be hardened, both under the same storm type. The Monte Carlo simulator performs these calculations for each investment activity for each simulated future.

For each Monte Carlo simulated future, the benefit-cost assessment is based on a discounted cash flow methodology over a 50-year time horizon. The benefit cost assessment for each investment activity is the sum of the avoided reactive costs and avoided monetized customer outages for each simulated event over the 50-year time horizon.

The module consolidates the Monte Carlo simulation calculations by averaging the various outcomes to estimate the statistical expectation for each investment activity's cost and benefit values. These key parameters are utilized within the Plan

Development Module to provide a comprehensive, customer centric, value-driven assessment.

4.2 Outage Mitigation Resilience & Risk Modeling Approach

The Outage Mitigation Resilience & Risk Modeling Approach utilizes the historical OMS data and recalculates each outage assuming the investments were originally in place. The approach fundamentally assumes future outages will be similar to historical outages. On average, this assumption is appropriate for performing the benefits assessment for investments. SPS's historical outage records for the last fourteen years for primary outages accounted for over 107,000 individual outage events. This modeling approach was utilized for the Distribution System Protection Modernization Program.

This data-driven approach provides a high level of precision in mapping benefits to investment activities, representing benefits to both the customer and the utility. This precision is especially needed to understand the benefits of distribution automation. The OMS includes various steps in the restoration process. These steps are needed to more accurately estimate the benefits of distribution automation, which modify each step of restoration once deployed.

Using each outage's recalculated CI and CMI, the DOE ICE Calculator monetizes the mitigated outages by considering the types of customers impacted, count of customers impacted, and outage duration. Additionally, the avoided cost of crew deployments, often referred to as "truck rolls," are included as a benefit to the utility for outages that are completely mitigated by investment.

The lifecycle present value of avoided customer outages and truck roll costs is calculated by adjusting for inflation and discount rate over the lifecycle of the investment. This produces a lifecycle present value of benefits that can be directly compared to the present value cost of the investment through the BCR.

$BCR = \frac{Benefit\ (Present\ Value\ \$)}{Cost\ (Present\ Value\ \$)}$ present value investment cost used to calculate the BCR should not be conflated with nominal values for the same investment. For example, a utility cost estimate for a multi-year investment is typically escalated by 2.5% per

year. This makes the cost estimate nominally higher than the present value cost, even though they both ultimately represent the same value.

4.2.1 Prepare Outage Management System Data and Customer Types

As discussed above, the Outage Mitigation Risk & Resiliency benefit approach is data-centric. The core data used for the analysis was the historical outage records provided by SPS. SPS provided fourteen years of historical outage records (2010-2023). The dataset provides granular information on the location, system, and customer-restoration process for each outage event. The analysis leverages the dataset to achieve a high-quality representation of historical outage impact and the future-looking impact of investment.

1898 & Co. regularly reviews outage management records for utilities. Typically, utility crews document cause codes for each outage, including descriptions of the cause of the outage, device type, and system impacted. The cause descriptions, device type, and system of the outage were important factors in identifying the outages that can be mitigated by investments in distribution automation and vegetation management. Identifying which outages can be mitigated by investment (and which outages cannot) provides a high level of precision in mapping benefits to investment activities. This level of precision is needed to more accurately estimate the benefits of both the Distribution System Protection Modernization. For this reason, 1898 & Co. utilized this approach to evaluate this measure.

Based on a utility's business processes, the cause code data within the OMS can range in quality over time and between different divisions and crews. SPS's record-keeping and outage data within the OMS is similar to other electric utilities. In general, 1898 & Co. found the outage data to be high quality and sufficient for use with the Outage Mitigation Resilience & Risk benefits assessment. The analysis utilizes all of the outage records (2010-2023) to better reflect SPS's current system and evaluate benefits more accurately.

SPS provided customer-type information with database ties to SPS's Geographical Information System (GIS) and OMS. Using this information, 1898 & Co. linked the type and number of customers impacted to each of the outages in the OMS.

This data allows for the monetization of outages using the DOE ICE calculator to evaluate the economic impact of customer outages for different customer types.

As a first step in the process, 1898 & Co. prepared the outage records in a mapped format to perform the outage mitigation calculations. This effort included organizing the step-by-step restoration process, excluding outages that are not applicable, connecting the GIS, customer information system (CIS), and OMS systems, and classifying outage records.

4.2.2 Mitigated Outage Calculations

This section outlines the general approach to re-calculating the outage records to account for additional resiliency investment. 1898 & Co. calculated three different benefit streams using this approach:

1. Sectionalization;
2. Automated Feeder Switching & Scheme Effectiveness; and
3. Mitigated Sustained Outages from Nuisance Events.

4.2.2.1 Sectionalization

1898 & Co. calculated the benefits associated with investing in midpoint reclosers to increase the sectionalization of distribution circuits across SPS's system. By increasing the sectionalization of a circuit, the customer impact from outages can be mitigated by isolating outage-causing faults using a midpoint recloser instead of a breaker or further upstream device. The model recalculates the outage assuming that midpoint reclosers had been in place and uses the DOE ICE calculator to monetize the new customer outage impact.

The model evaluates multiple sectionalization alternatives to identify the number of reclosers that maximize customer benefit for each circuit. Where the benefits of adding a mainline recloser outweigh the cost of placing the recloser, the customer

benefits from adding that recloser. The model takes into consideration SPS's operational reality (minimum of 1 mainline recloser per 10 primary miles) on the maximum number of reclosers that are technical feasible, while maximizing benefit with the number of sectionalization reclosers.

The model identifies outages on the mainline of the circuit (not on fused laterals) that are candidates for improvement from adding midpoint reclosers. Fuse outages will continue to operate before the mainline recloser for faults downstream of the recloser. These outages do not share in the benefit from adding sectionalizing reclosers. By excluding lateral outages that are caught by fuses from receiving sectionalizing benefits, the model provides a precise mapping of benefits associated specifically with the investment required.

The figures below represent a simplified diagram of a circuit before (Figure 4-3) and after (Figure 4-4) investing in sectionalization. Without sectionalizing reclosers, a fault on the mainline of the circuit requires the breaker to operate, and all 1,500 customers downstream from the breaker experience an outage. In this example, crews take 60 minutes to identify the outage location, clear the outage, and restore power. 1,500 customers interrupted for 60 minutes results in 90,000 CMI for the event.

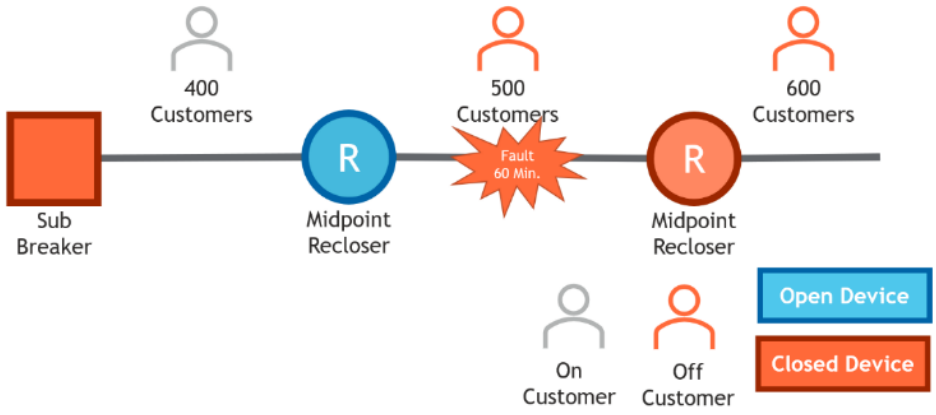
Figure 4-3: Simplified Outage Example without Sectionalizing Reclosers



In the investment scenario for midpoint reclosers, shown below, a recloser isolates the fault. Due to the sectionalization afforded by the midpoint recloser, the 400

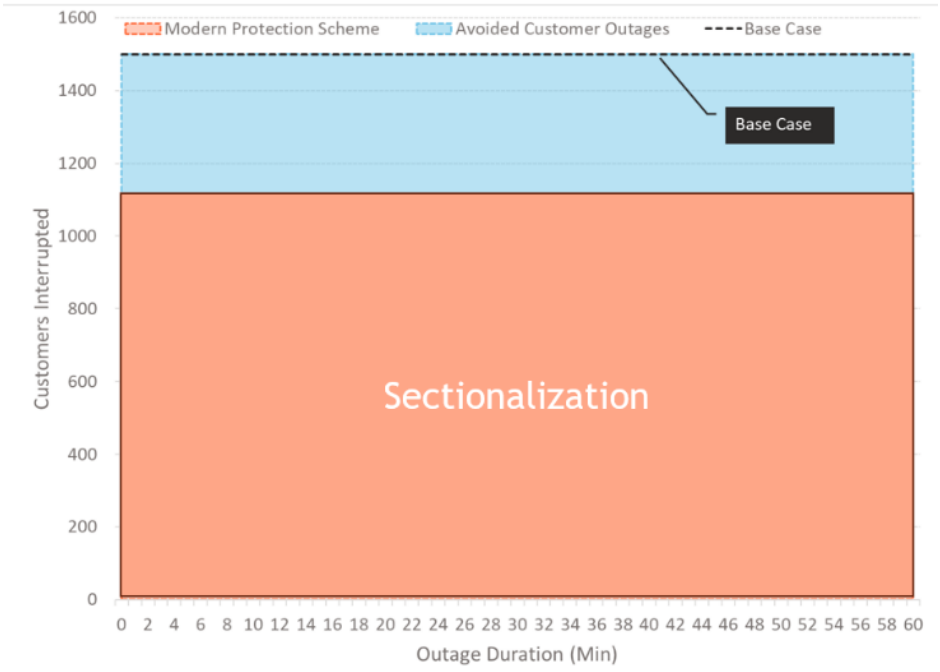
customers upstream of the recloser do not experience an outage. Only 1,100 customers are impacted in this scenario, with a resulting CMI of 66,000 (1,100 customers interrupted x 60 minutes). Additionally, the model takes a weighted average of the customers interrupted to account for the fact that some faults will continue to occur upstream of any new reclosers and result in a breaker operation. While there is likely some improved response speed due to the known locations of the reclosing devices, the investment scenario conservatively assumes the job duration will remain the same as in the Status Quo scenario.

Figure 4-4: Simplified Outage Example with Investment in Sectionalizing Reclosers



The customer benefits from investing in sectionalizing reclosers are calculated from the avoided $CMI. The figure below shows the avoided CMI between the two scenarios. The blue section represents the avoided customer outages, which represents the customer benefit due to sectionalization.

Figure 4-5: Example of Sectionalization Benefit

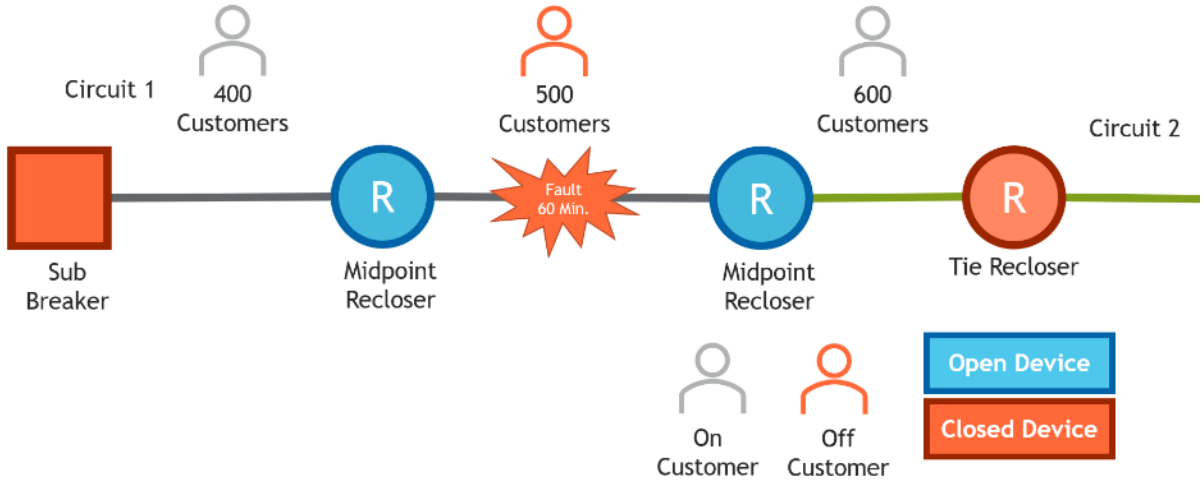


4.2.2.2 Automated Feeder Switching (AFS) Schemes

1898 & Co.'s Outage Mitigation Resilience & Risk model evaluates the benefits of investing in automated ties and communications necessary to create Automated Feeder Switching (AFS) schemes. Based on the mapping of new devices to the OMS, 1898 & Co. recalculated the impact of mainline outages assuming the new customer count in each sectionalization pod and transferring customers not within the faulted pod to the adjacent circuit.

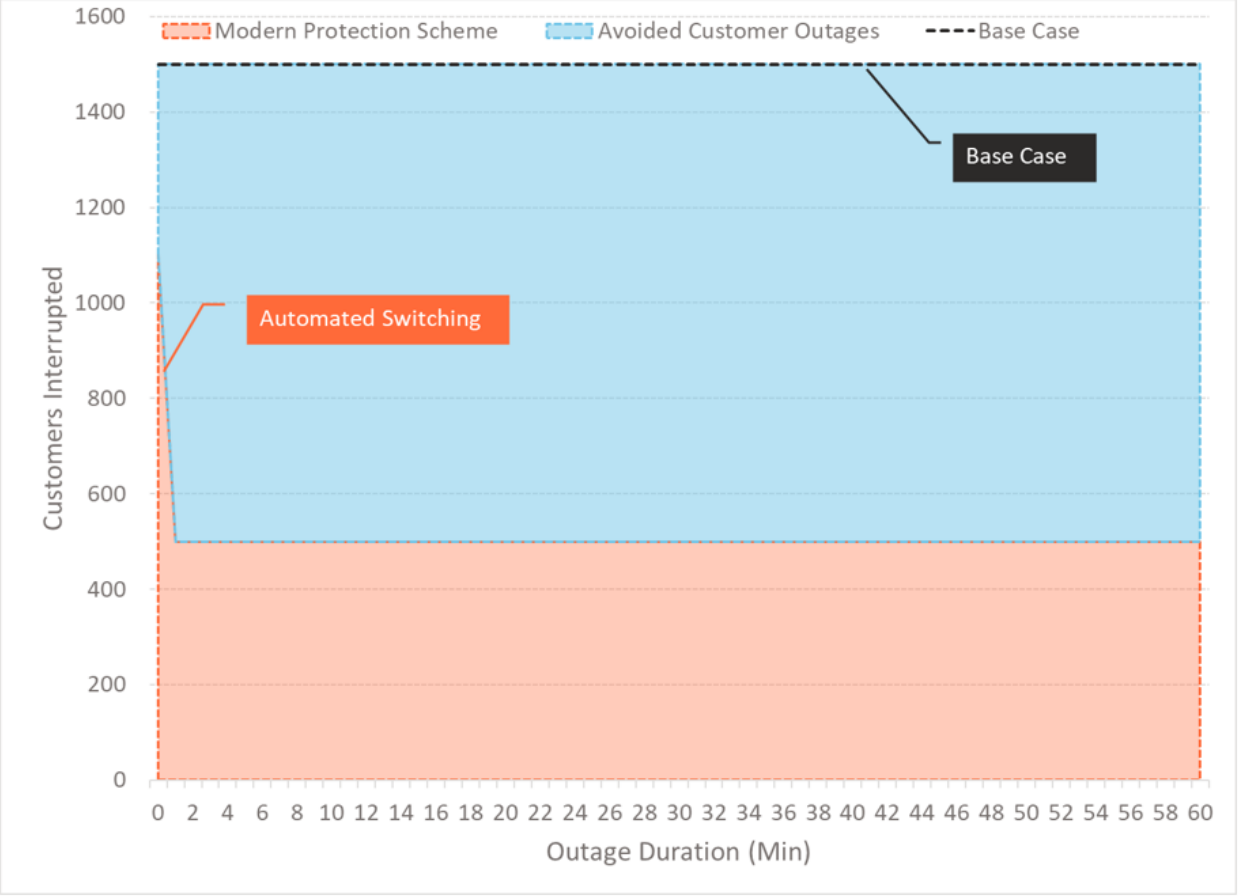
Figure 4-6 shows a simplified example of a circuit with reclosers added to support an AFS scheme. This example represents the same 60-minute outage that occurs on a feeder with 1,500 customers downstream of the substation breaker. In this example, the fault is detected by the most upstream recloser, which operates and disconnects the 1,100 customers downstream of it. As part of the AFS scheme, the midpoint recloser downstream of the fault opens, and the tie recloser to an adjacent circuit closes. This allows the pod of customers downstream of the faulted pod to only experience a momentary outage and be restored within the automated switching time.

Figure 4-6: Simplified Diagram of Circuit with AFS Scheme



It should be noted that the original number of customers impacted, and the duration of the entire outage is the same. The difference is in the ability to restore customers through AFS rather than manual back feeding. The example is a 1-hour outage with 1,500 customers initially without power. The ability to perform AFS substantially decreases the overall CMI in this example. It should be noted that from a NERC system performance reporting perspective, the improvement is even higher, given that only outages longer than five minutes are officially reported. This means the initial outage before switching would not be reported except for those customers who cannot be restored by the switching operation.

Figure 4-7: Mainline Outage Profile before and after AFS Investment



During major events, these investments may not operate if the supporting infrastructure (*e.g.*, tie lines and neighboring circuits or substations) is impacted. The analysis applies Major Event Days (MED) and non-MED effectiveness to be conservative. An additional constraint is placed on the effectiveness of the AFS schemes where neighboring circuits do not have capacity to manage additional load.

4.2.2.3 Mitigating Sustained Outages from Nuisance Events

The lateral reclosing deployment includes the replacement of fuses with reclosing devices. With fuses, whenever a fault current is detected, the fuse blows, causing downstream customers to be without service. Once crews are mobilized and the underlying outage cause is fixed, the fuses are replaced to restore service. In the case of nuisance outages like vegetation 'slapping' power lines, crews cannot identify any real infrastructure issue, and they simply replace the fuse. For these nuisance events, the fault current may have only occurred for a few cycles (*i.e.*, 1/60th of a second).

The number of nuisance events can be significant for utilities, causing customers to be without service for 45 minutes to 2 hours depending on the time for crew mobilization and on the time required to investigate the outage cause.

Lateral reclosers are 'smarter' devices that are programmed to investigate if the outages are real or nuisance. They act very similarly to reclosers 'blinking' to determine if the fault current still exists. Where the fault current is maintained over several trips or 'blinks,' the device locks out. Crews are then mobilized to fix the underlying system issue. When the fault current is not maintained, the lateral recloser only 'blinks' momentarily and then restores service permanently. In addition to mitigating longer customer outages, this investment also mitigates the cost of deploying a crew (estimated at $1,000 per avoided truck roll).

1898 & Co. reviewed the historical outage records and identified likely nuisance outages. These include animal, weather, and vegetation outages less than 90 minutes in duration, which is the approximate time for a crew to drive to the circuit, find the fault location, and reset the fuse. The redesigned protection scheme with lateral reclosers changes these events to 'blinks,' saving customers from up to 90-minute outages and the cost of rolling a truck.

For the purpose of calculating the cost of an outage, any outage less than one minute was assumed to be a one-minute outage. For example, the before-lateral recloser state is a 90-minute outage for 50 customers, and the after-lateral recloser investment state is a one-minute outage for 50 customers. This is a conservative assumption. It could also be argued that the customer cost of a 'blink' should be much lower than a one-minute event. The overall benefit of lateral recloser increases significantly if the cost of a 'blink' is calculated at its true value, which is much closer to zero than to a one-minute outage.

4.2.3 Normalization, Monetization, and Lifecycle Benefits Calculation

The mitigated outage improvement was normalized and annualized to a single year, averaging any significant year-to-year discrepancies between outage types, outage causes, and circuits. The normalized and annualized value was then monetized using

the DOE ICE Calculator and customer profile for each outage. Section 5.5 outlines the ICE Calculator assumptions and the benefit of avoiding 'blinks.' Applying escalation, a discount rate, and a 25-year expected useful life for the investments, the lifecycle benefit was calculated for each outage event and rolled up to the circuit level.

4.3 Equipment Failure Resilience & Risk Modeling Approach

The Equipment Failure Risk & Resiliency modeling approach calculates the benefits of replacing existing infrastructure. It utilizes a risk and resiliency-based planning approach to forecast the probability-weighted consequence of failure for a range of failure types. The failure types are based on how assets fail over their lifecycle, including inspection-based failures. Consequences are estimated for a range of factors but fall into two main categories. The first category is reactive or restoration costs. The second category is customer-based outages. This category is the monetization of customer outages in the event of an asset failure.

Additionally, the approach calculates each asset's lifecycle reactive costs and customer outage costs for two scenarios. The first is a Status Quo scenario where the asset is not proactively replaced; the second scenario is the Investment scenario in which the asset is upgraded proactively to the new equipment standard. The benefit of replacing infrastructure is the difference between the two scenarios, the avoided risk and resiliency lifecycle costs. This analysis provides a clear calculation of expected benefits from implementation of particular resiliency measures.

The following subsections outline this approach in further detail. The subsections use a 30-year-old hydraulic recloser on the mainline as an example to show the benefit calculations. The same approach was used for all asset classes shown in Table 4-1.

Table 4-1: Equipment Evaluated for Failure Risk & Resiliency Benefit

Circuit Assets	Substation Assets
Distribution Poles	Relays
Distribution Conductors	Breakers
Reclosers	
Open Wire Secondary	
Pole Top Transformers	

4.3.1 Probability of Surviving

Many of the asset classes included within SPS's SRP are typically replaced before failure-causing outages. This replacement is because the consequence of failure typically exceeds utilities' risk tolerance levels. For this reason, utilities actively inspect the assets, perform testing, and collect real-time condition information. When assets exceed a condition tolerance, they are proactively replaced subject to detailed engineering evaluations, budgeting considerations, and prioritization of needs. While there are historical equipment failures, the number of failures and data quality is insufficient to enable a statistical analysis to calculate reliable historical failure rates for SPS's assets. In the absence of historical failure rates, Survivor curves or End-of-Life curves can be utilized to approximate the probability of an asset not surviving over time.

Each asset class designated in Table 4-1 was assigned an Iowa Survivor Curve inside the Equipment Failure Resilience & Risk Mitigation analytics model. Figure 4-8 shows an example End-of-Life (Iowa Survivor Curve) for a hydraulic recloser. Figure 4-9 shows the approach to calculating the annual probability of not surviving for a 30-year-old hydraulic recloser.

Figure 4-8: Example Survivor Curve for Hydraulic Recloser

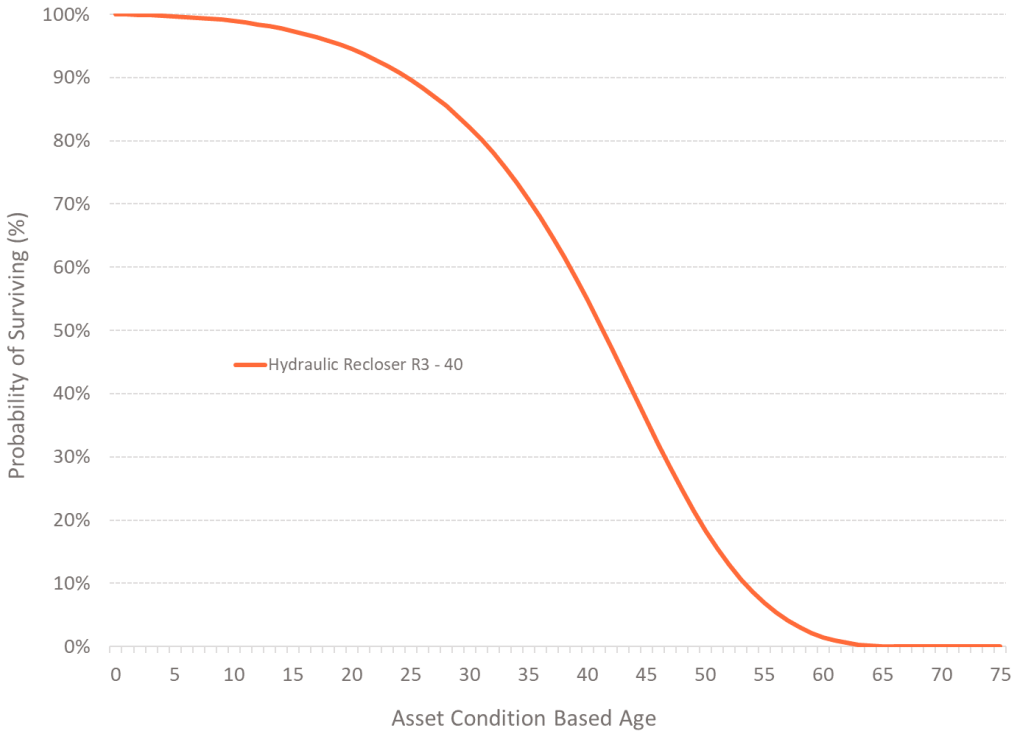
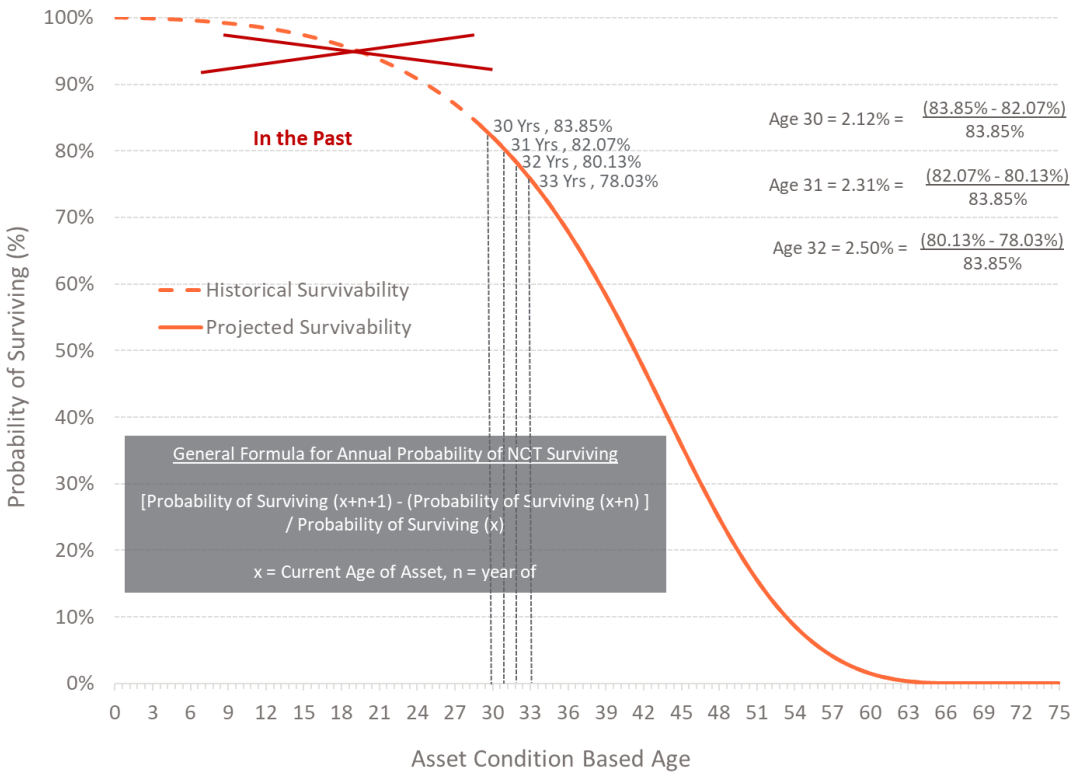


Figure 4-9: Annual Probability of Not Surviving Example – 30-Year-Hydraulic Recloser



The survivor curves allow for the calculation of the annual probability of an asset not surviving over time. The curves produce a probability density function where the total probability is 100%. The curves are used to forecast the probability of not surviving based on an asset's condition-based age. Figure 4-10 shows the annual probability of not surviving for a range of hydraulic recloser ages based on the mathematical approach shown in Figure 4-9. The figure shows that, as assets get older, the 100% probability of not surviving each successive year is distributed over fewer years, thereby increasing the annual probability of failure for older assets.

Figure 4-10: Survivor Curves to Annual Probability of Not Surviving Profiles for Hydraulic Reclosers

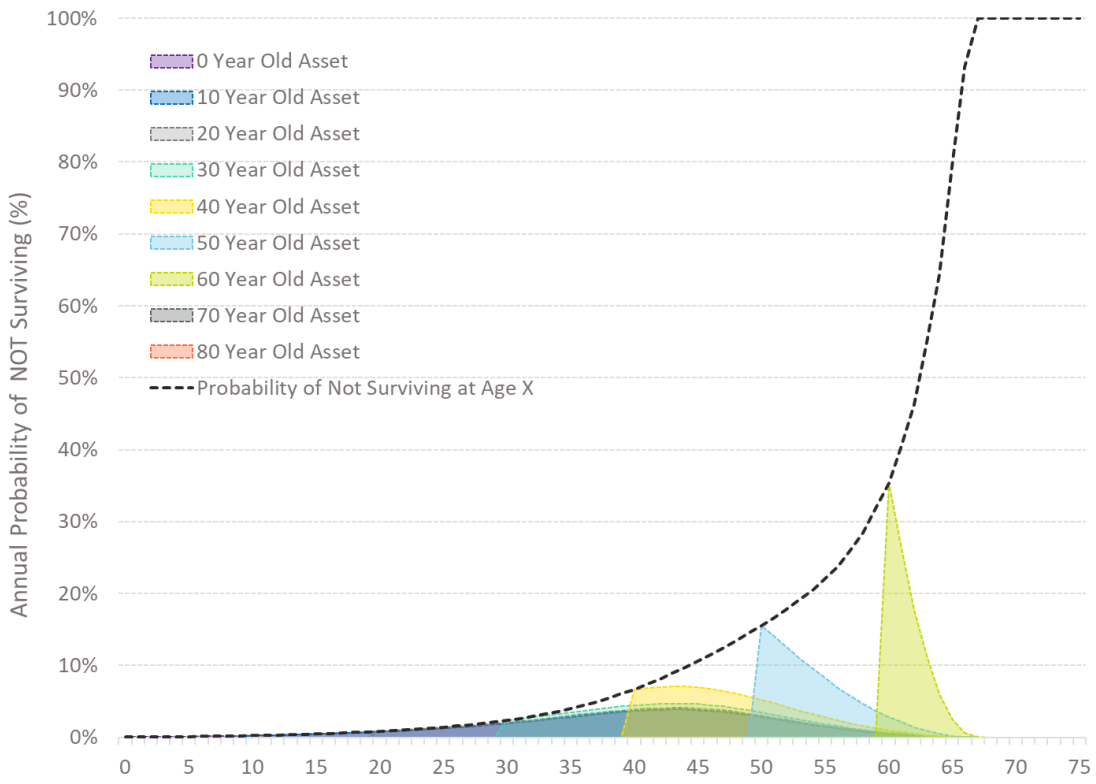


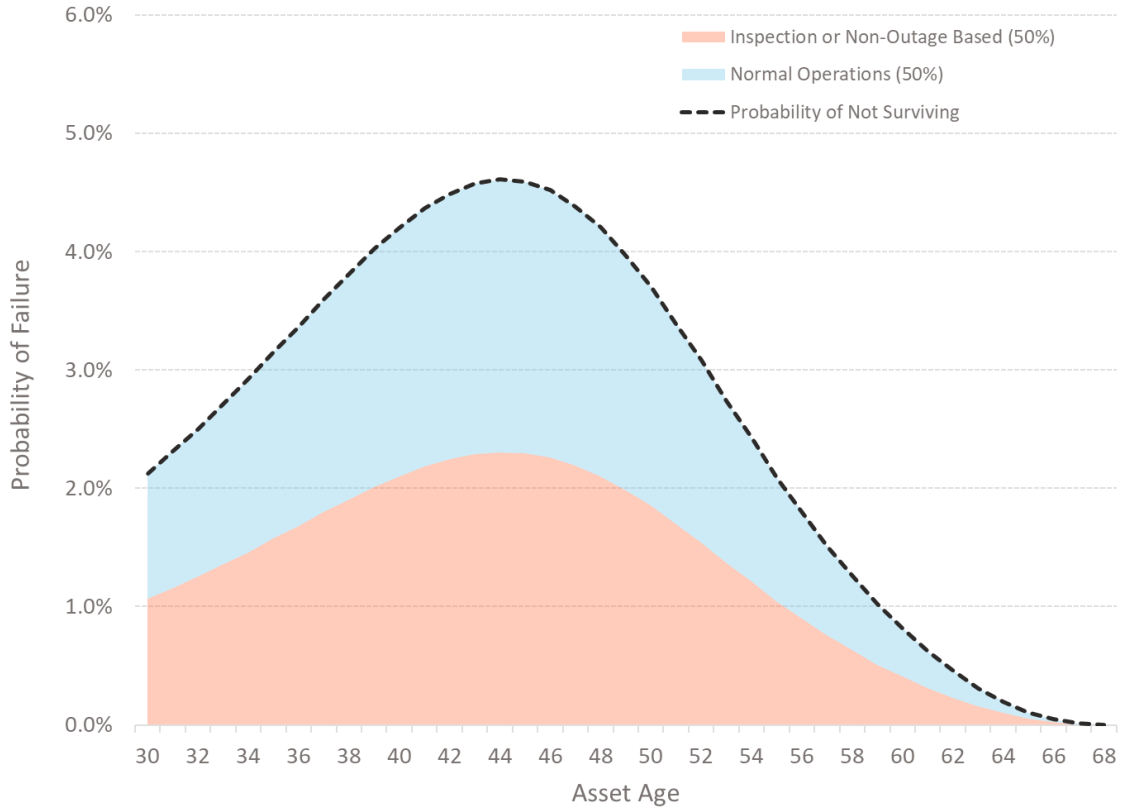
Figure 4-10 also shows the probability of not surviving at each age (Probability of Not Surviving at Age X). It is important to note that this representation of the Survivor curve produces a 'Bathtub' curve for reclosers. Each asset class survivor curve produces a different representation of failure rate profiles as assets age. The Equipment Failure Resilience and Risk Mitigation model calculates the probability of not surviving for each asset included in the evaluation.

4.3.2 Failure Types and Probability of Failure

The previous section described the approach to forecast an asset's annual probability of not surviving over time. Assets fail to survive a given year for many reasons. For example, a wood pole may be replaced due to failed inspection or after a major storm event. 1898 & Co. has developed a library of failure type profiles for T&D infrastructure assets. That library is codified within the Equipment Failure Resilience

& Risk model. Figure 4-11 shows the probability-of-failure profile for each failure type for the example 30-year-old hydraulic recloser.

Figure 4-11: Failure Types and Probability of Failure for 30-Year-Hydraulic Recloser



For hydraulic reclosers, one expected failure type is an inspection or non-outage-based failure in which the utility inspects the recloser and determines that it does not meet minimum engineering standards. As the figure shows, this failure type is expected to occur 50% of the time.

4.3.3 Consequence of Failure

For each failure type, the risk framework library inside of the Equipment Failure Resilience & Risk Mitigation model includes a range of consequence types based on expected impact should the asset fail. Table 4-2 shows the range of consequence types evaluated and the asset classes that they apply to. The table also shows the

avoided cost type. The framework puts a monetary value on each of these consequence factors.

Table 4-2: Consequence Types and Asset Class

Consequence	Avoided Cost Type	Circuit Assets	Substation Assets
Customer Outages	Customer Outage	■	■
Equipment Failure Costs	Reactive	■	■
Collateral Damage	Reactive		■

4.3.3.1 Customer Outage Impact

One of the main consequences of failure across all asset classes is the impact on customers. When assets fail, the protection schemes are activated to protect the system against fault currents, limiting customer outages. The protective interventions cause customer outages for the time it takes to restore the system. The relationship between assets and customers was established for all circuit and substation assets (see Sections 5.1 and 5.4).

For each asset and failure type, the expected duration of the outage was estimated based on typical restoration times. For example, the expected duration to replace a hydraulic recloser during a “normal operations” type of event is approximately 4 hours, because crews are likely readily available.

Based on the expected duration of each failure type for each asset and expected customers impacted (Section 5.4), including accounting for customer type, the approach calculates the risk-weighted CMI for each asset. This risk-weighted CMI is monetized using the DOE ICE Calculator (see Section 5.5) to estimate each asset's risk-weighted $CMI over time.

4.3.3.2 Equipment Failure Costs

When assets fail before being proactively replaced, it creates an urgency to repair or replace the asset to minimize the impact to the customer. The level of urgency is generally proportional to the failure types outlined in Figure 4-12. This urgency results in a level of effort that is not without cost. These additional costs are

captured under the category of equipment failure costs. The magnitudes of these costs are different depending on the failure type. Crews are generally available during "normal operations" (non-storm) failure types, but capital efficiencies are lost as the mobilization is generally for only one asset. During the various "gray sky" (storms/medium severity) failure types, overtime is generally authorized to restore electric power as soon as possible. During a major "gray sky" failure (major storm/catastrophic failures), crews from neighboring utilities are often utilized to minimize the impact to the customer. These costs can be significant. For these types of events, it is not uncommon for the cost of replacement to be more than double the cost of proactive replacement.

Equipment Failure costs were estimated for all asset categories and all failure types. Combined with the annual probabilities for each failure type, these values are used to calculate the failure cost profiles for all assets.

4.3.3.3 Collateral Damage

Substations are an area of high energy transfer. This high energy in combination with an asset failure can result in a catastrophic failure that may result in a fire or explosion, especially if arcing occurs. The fire or explosion is generally not contained to the asset that failed. The result is collateral damage to other assets within the substation and, in rare circumstances, to property outside the substation boundaries. These collateral damage costs can vary significantly, from thousands to millions of dollars. As assets age, particularly power transformers and breakers, the probability of this type of failure increases. While statistically rare, these high to extreme costs are factored into the analysis for substation assets.

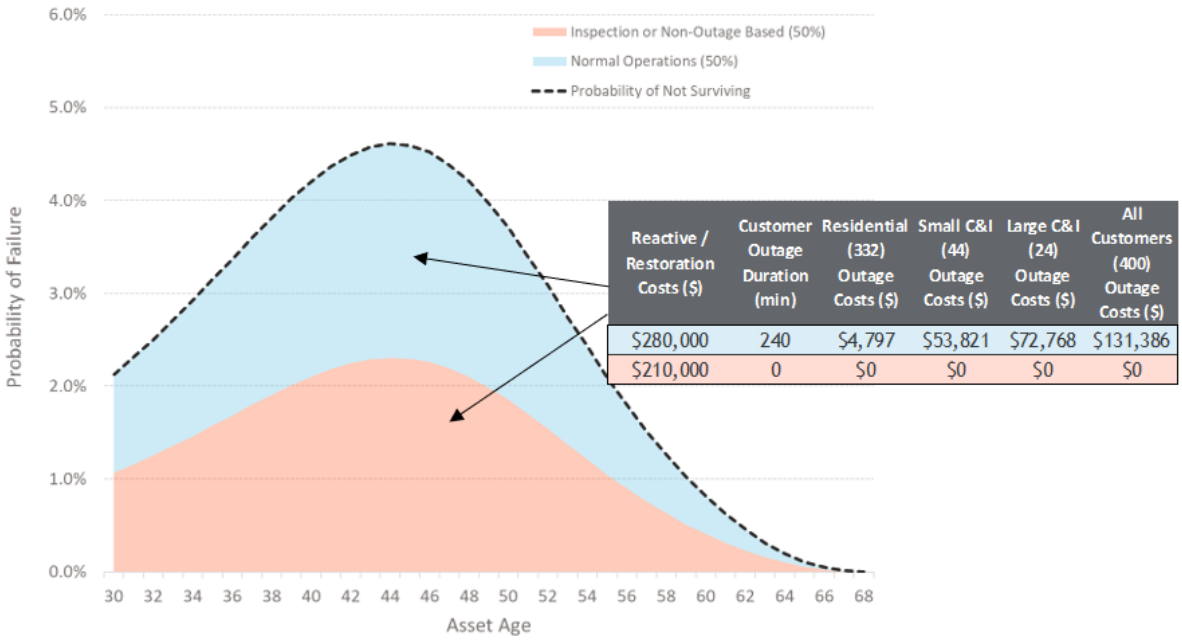
4.3.4 Status Quo Risk & Resiliency Profile

As discussed above, the evaluation calculates the risk & resiliency costs profile over time for two scenarios: the Status Quo Scenario and the Investment Scenario. The Status Quo scenario assumes the asset is not proactively replaced and could incur risk costs over time. To calculate the Status Quo Risk & Resiliency costs over time, the probability of failure for each failure type is multiplied by the cost consequence for

each failure type. Figure 4-12 depicts this approach for the 30-year-old hydraulic recloser example on a mainline with approximately 400 customers. The figure shows the number of residential, small C&I, and large C&I customers for this example.

Figure 4-13 and Figure 4-14 show the Status Quo Risk & Resiliency Costs for reactive and restoration costs and customer outage costs, respectively. The profiles are based on multiplying the probabilities of failure in Figure 4-12 by the economic consequence values and applying the escalation and discount rate from above. Figure 4-13 and Figure 4-14 each show the percentage of total risk and resiliency costs for each failure type. Figure 4-15 is the sum of Figure 4-13 and Figure 4-14 for each year and shows the total risk & resiliency costs for the 30-year-old hydraulic recloser.

Figure 4-12: Status Quo Risk & Resiliency Calculation 30-Year-Old Hydraulic Recloser



Reactive / Restoration Costs ($)	Customer Outage Duration (min)	Residential (332) Outage Costs ($)	Small C&I (44) Outage Costs ($)	Large C&I (24) Outage Costs ($)	All Customers (400) Outage Costs ($)
$280,000	240	$4,797	$53,821	$72,768	$131,386
$210,000	0	$0	$0	$0	$0

Figure 4-13: Status Quo Resilience & Risk Reactive Costs Profile - 30-Year-Old Hydraulic Recloser

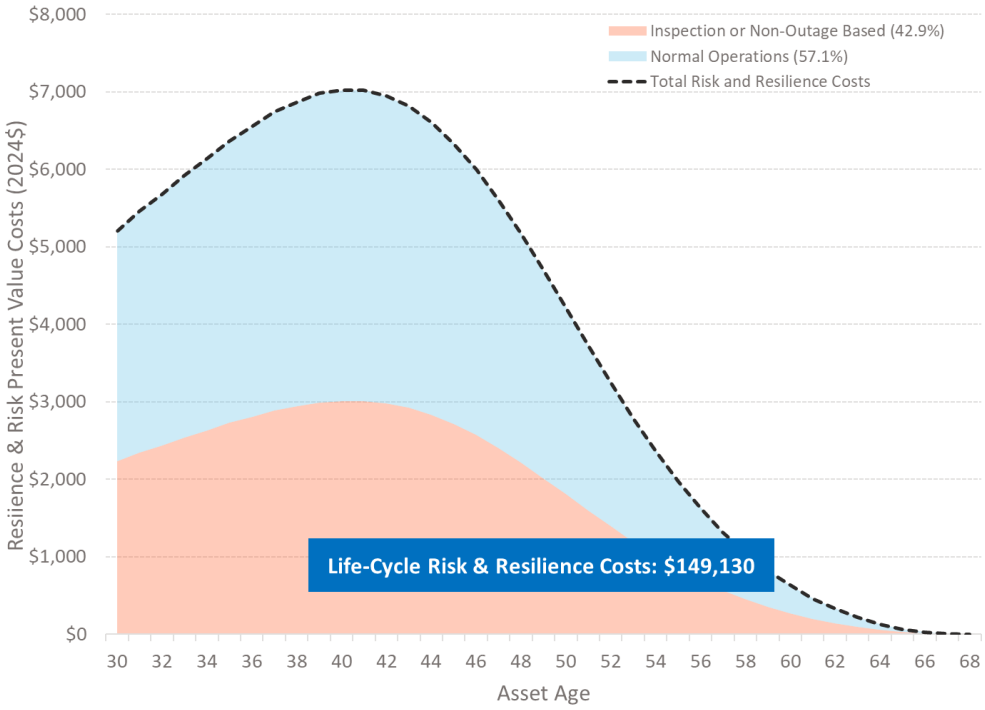


Figure 4-14: Status Quo Resilience & Risk Customer Costs Profile - 30-Year-Old Hydraulic Recloser

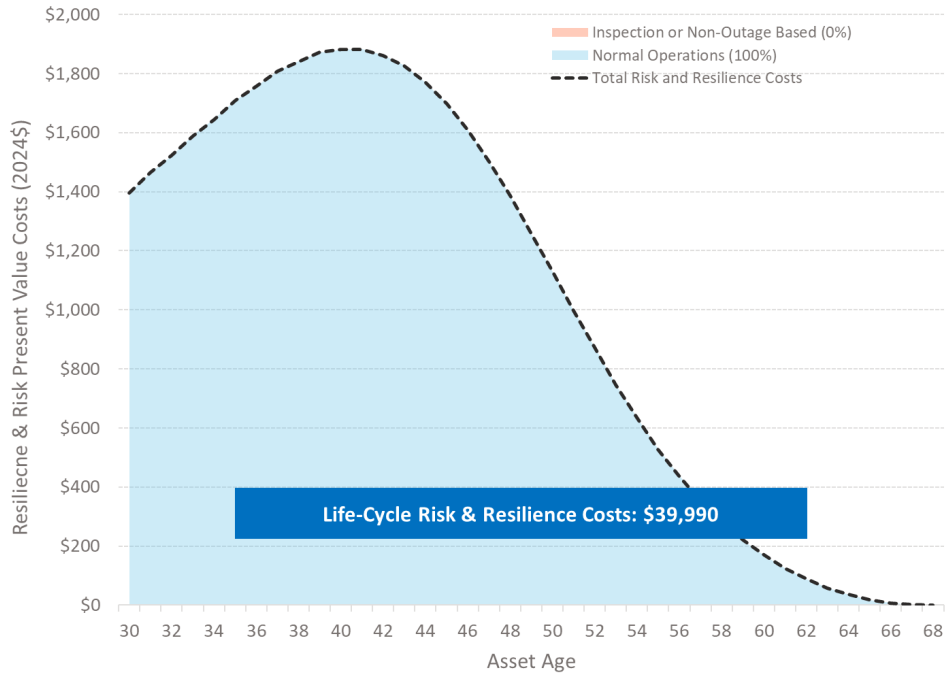
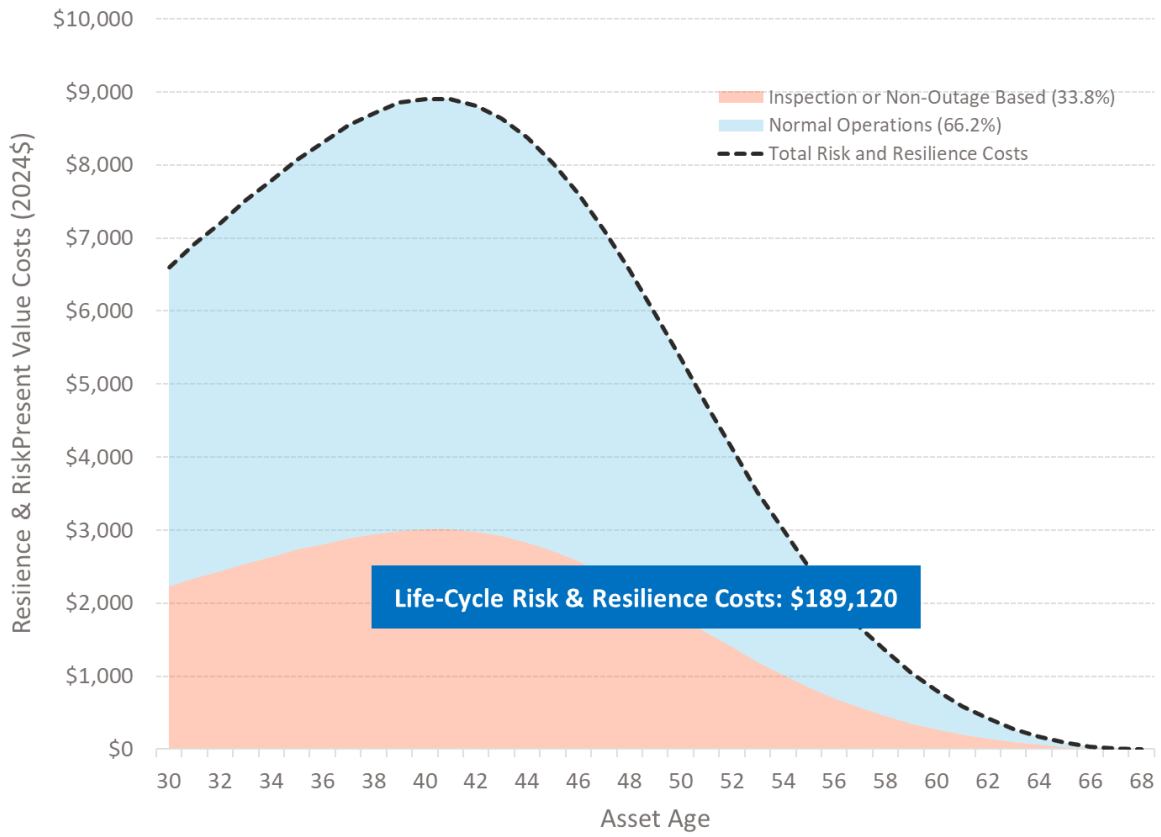


Figure 4-15: Status Quo Resilience & Risk Costs Profile - 30-Year-Old Hydraulic Recloser



4.3.5 Avoided Risk & Resiliency Cost-Benefit Calculation

The second scenario evaluated for each asset is the Investment Scenario. This scenario assumes the asset is replaced. By replacing the asset, the near-term failure probabilities decrease since the asset is now 0 years old. In some cases, the failure types change with the replacement, such as oil circuit breakers that are replaced with gas breakers. The avoided resilience and risk benefit for infrastructure upgrades is the difference between the Status Quo and Investment scenarios.

Figure 4-16 and Figure 4-17 show the failure probabilities of the Status Quo and Investment scenarios for the 30-year-old hydraulic recloser example. Over the 39-year expected remaining life for the 30-year-old hydraulic recloser, there is a 100% probability of that recloser not surviving. If the recloser is replaced, there is an

approximately 42% probability of that recloser not surviving over the same 39-year time horizon. The figures also show the lifecycle probabilities for each failure type.

Figure 4-16: Status Quo Probability of Failure Profiles

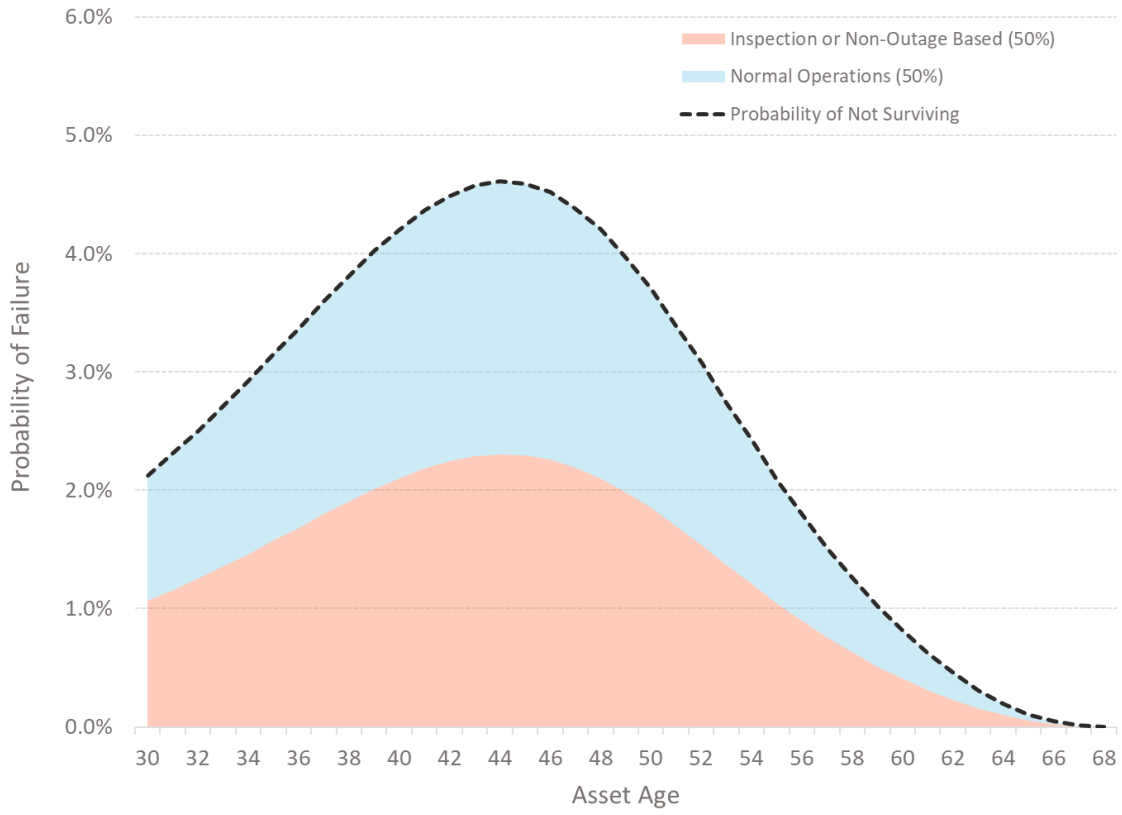


Figure 4-17: Investment Scenario Probability of Failure Profiles

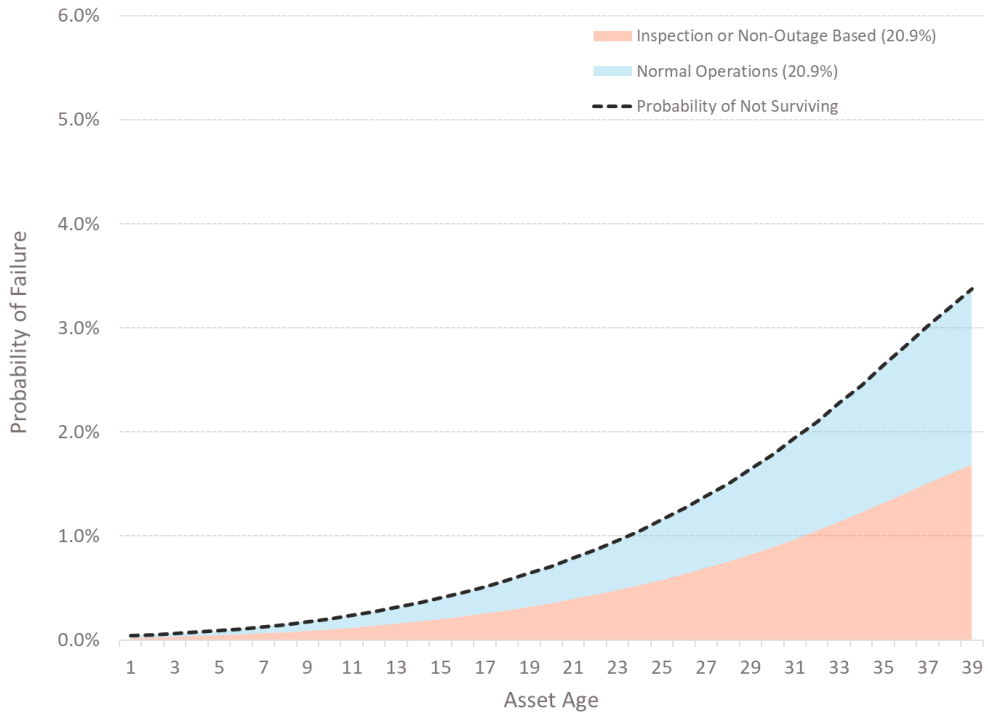


Figure 4-18 and Figure 4-19 show the companion resilience and risk cost profiles for the Status Quo and Investment scenarios. Figure 4-20 shows the total values from Figure 4-18 and Figure 4-19 and the annual difference (Status Quo – Investment). The annual difference is the avoided annual costs of replacing the 30-year-old hydraulic recloser. In the first 25 years of the profile, the avoided costs are positive, with the remaining being negative. The life cycle avoided benefit-cost is approximately $144,110 (present value dollars) for replacing the hydraulic recloser. The example hydraulic recloser costs approximately $140,000 to replace, giving this example investment a BCR of 1.02. If the recloser were younger, the annual avoided costs would turn negative sooner and make the investment activity less beneficial.

Figure 4-18: Status Quo Risk & Resiliency Cost Profiles

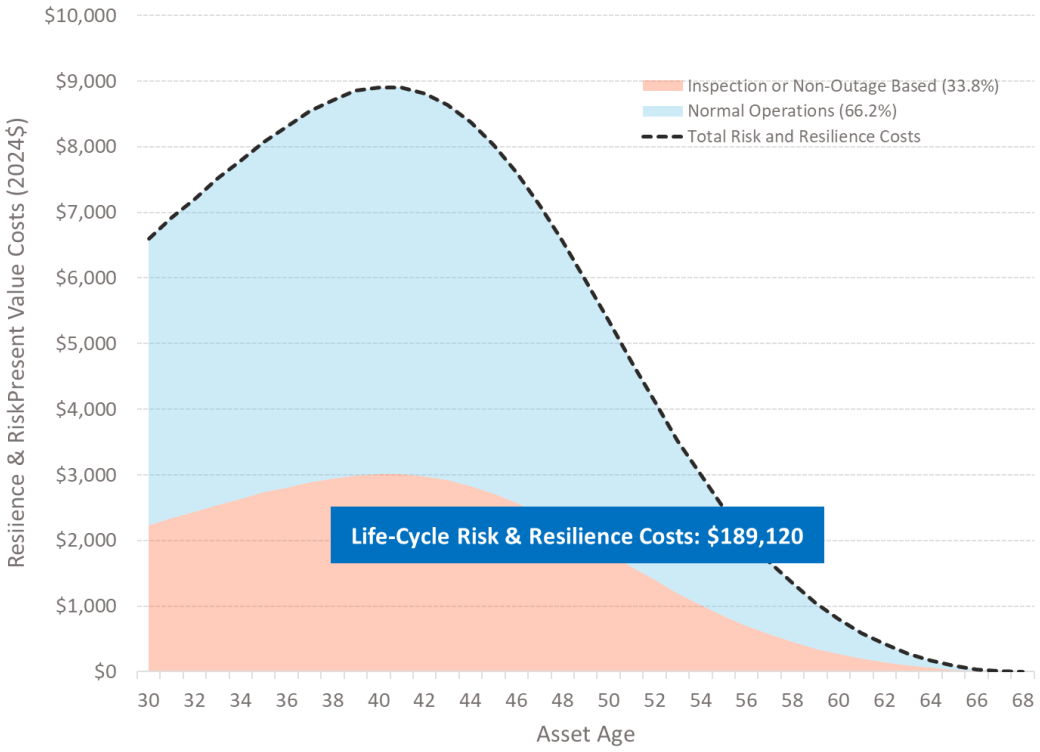


Figure 4-19: Investment Scenario Risk & Resiliency Cost Profiles

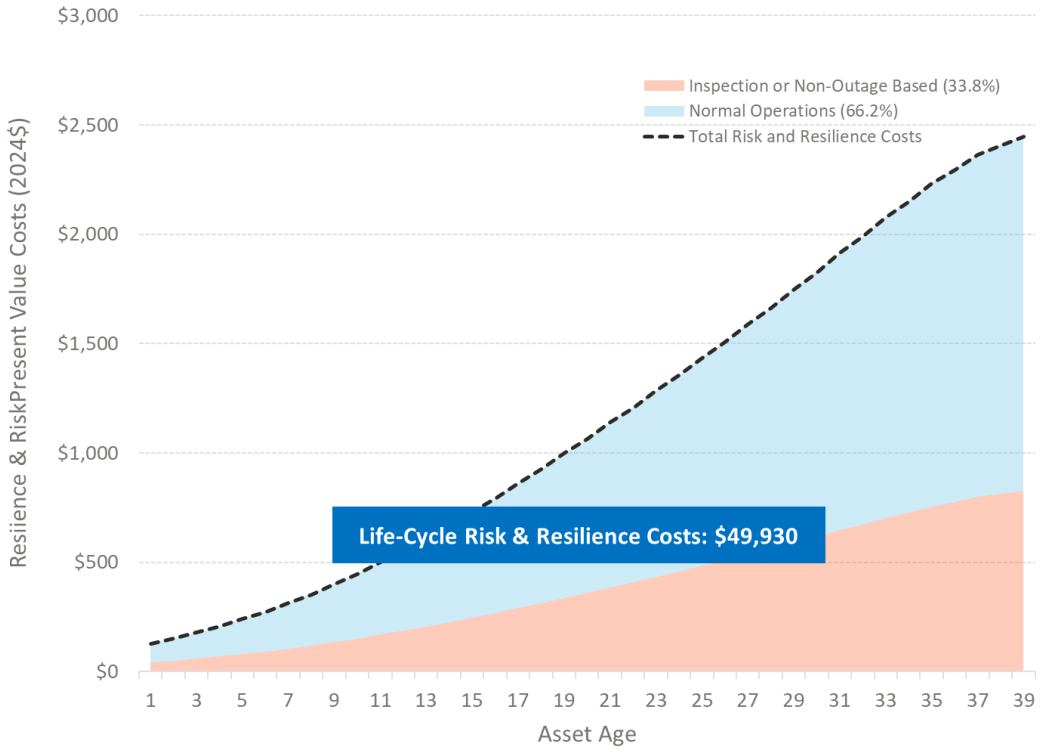
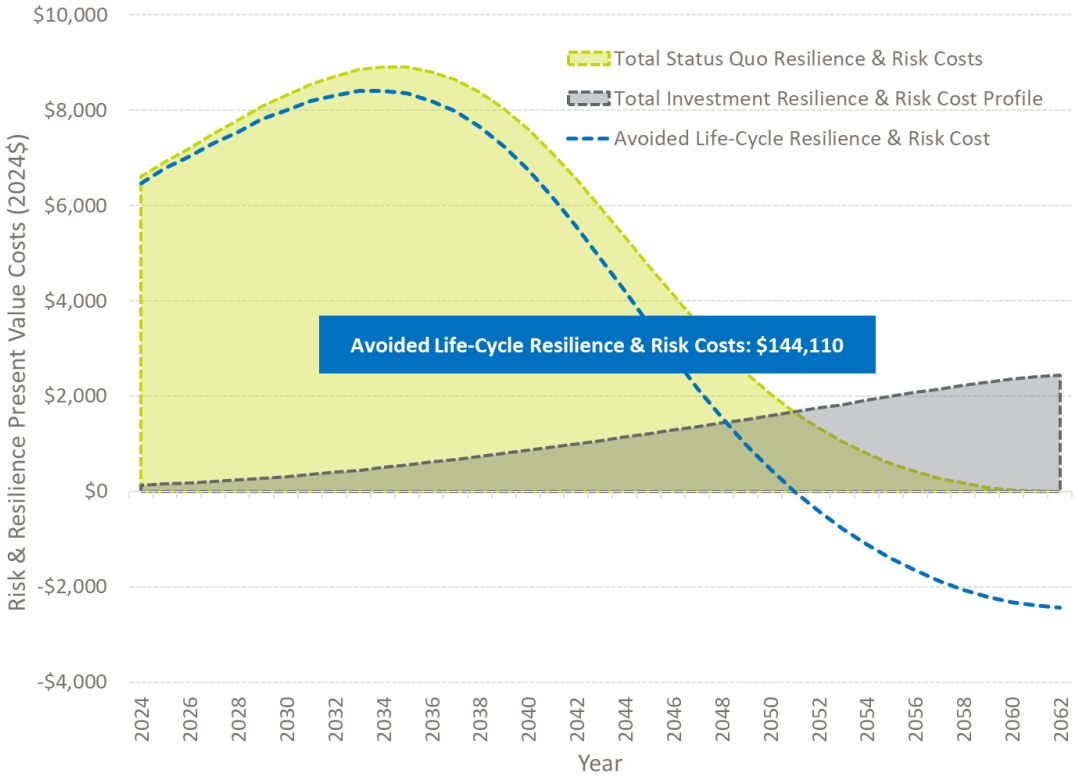


Figure 4-20: Avoided Risk & Resiliency Cost-Benefit



4.4 Qualitative Approach

The previous sections have outlined the various methods for quantifying the benefit of specific investments. However, it is difficult to fully capture and quantify all of the factors that go into every investment decision. Qualitative considerations generally fall into two categories: indirect influence and safety/security. Indirect influence includes topics such as:

- Economic stability and attractiveness;
- Customer anxiety; and
- Bolstering performance for lower performing areas.

Resilience investment contributes to the economic stability and general attractiveness of both businesses and residents. The investment also reduces customer anxiety that results when customers lose power. While these benefits are generally accepted as legitimate for consideration, their values are difficult to quantify directly. Thus, they were not quantified in 1898 & Co.'s modeling.

Lower performing areas generally justify investment to address needs that cause the level of service to be considerably below the average expected level of service for a significant period of time. While there may not be a strong business case based on the monetization of CMI, sustained poor performance should be addressed with investment to improve performance in these areas. The Resiliency Rule specifically includes improving service quality to areas of lower performance as a benefit to be considered in approving a system resiliency plan.

Safety risks and consequences for both the general public and SPS employees are challenging to monetize and incorporate into the investment evaluation and justification framework based on BCR. Accordingly, while all of the measures in SPS's SRP provide safety benefits to some degree, 1898 & Co.'s quantitative evaluation does not directly include safety mitigation benefit streams. Rather, when evaluating benefit cost results, 1898 & Co. balances the quantified benefits results and safety risk mitigation. As it applies to investment justification for investments with BCRs less than 1.0 but greater than 0.9, mitigating the general safety risk, improving service quality to areas of lower performance, and other qualitative considerations would provide sufficient direct benefits such that the total benefits would be in excess of the costs. Investment activities with a BCR of less than 0.9 should be evaluated for investment on a case-by-case basis.

5.0 Core Data Analytics and System Vulnerability

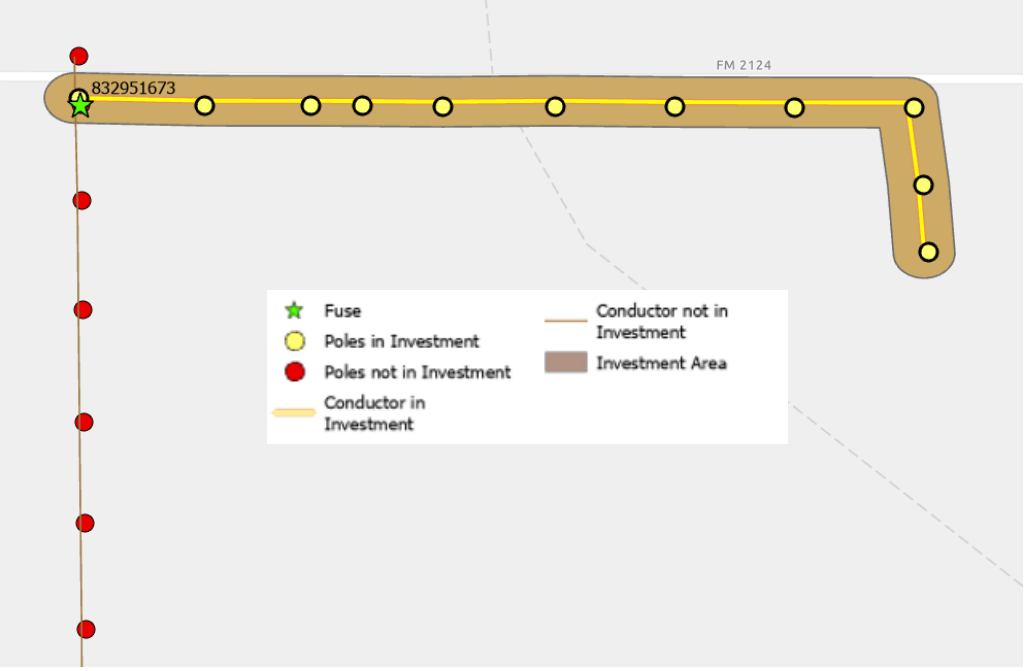
16 TAC § 25.62(c)(2)(B)(iii)
The resiliency plan must include a description of the system characteristics that make the electric utility's transmission and distribution systems susceptible to each identified resiliency event type.

The resilience and risk-based planning approach and methodology is data-driven. This section outlines the core datasets and base algorithms employed within the Integrated Resilience & Risk Investment Model. The section also outlines the system vulnerabilities that were included in the evaluation of the distribution system.

5.1 Geographical Information System (GIS)

The GIS provides the list of circuit assets in SPS's system and how they are connected to each other. Since the resilience and risk-based planning approach is fundamentally a bottom-up asset management methodology, it starts with the asset data, then rolls all the assets up to investment activities, all investment activities into programs, all programs into circuits, all circuits up to measures, and finally the measures up to the SRP. The relationship between assets and investment activities is illustrated in the geospatial figure below, Figure 5-1, for an overhead hardening rebuild investment activity. It should be noted that the SRP only includes investments in vulnerable infrastructure. For illustration purposes, it is assumed all the assets in this example are vulnerable.

Figure 5-1 Asset to Investment Activity Relationship



In alignment with this methodology, 1898 & Co. utilized the connectivity within SPS's GIS to link each distribution voltage asset up to a lateral (fuse protection device) or feeder (breaker or recloser protection device) to establish discrete protection zones. This linkage of assets to protection zones provides a granular evaluation of the distribution system that allows hardening investments to target only portions of a circuit for resilience investment. Through this approach, 1898 & Co. was able to use the asset-level information from Table 5-1 and convert it to the investment-activity level summaries in Table 5-2. Each investment activity includes the vulnerable assets from Table 5-1 organized at the protection zone level, which provides a bottom-up analysis.

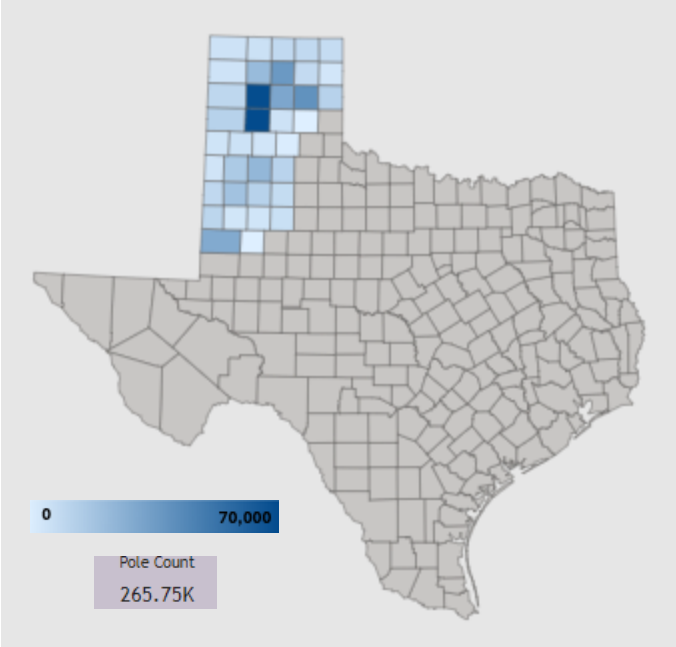
Table 5-1: SPS's Distribution Circuit Asset Base Evaluated

Asset Type	Units	Value
Distribution Circuits	**[count]**	**477**
Mainline Poles (Breaker/Recloser)	[count]	**92,353**
Lateral Poles (Fuse)	[count]	**173,810**
Mainline OH Primary (Breaker/Recloser)	[miles]	**4,019**
Lateral OH Primary (Fuse)	[miles]	**6,624**
Pole Top Transformers	[count]	**56,758**
Hydraulic Reclosers	[count]	**53**
Air Breakers	[count]	**6**
Oil Breakers	[count]	**59**
Vacuum Breakers	[count]	**310**
Open Wire Secondary	[miles]	**1,269**
Electromechanical Relays	[count]	**1,198**
Microprocessor Relays	[count]	**508**
Solid State Relays	[count]	**5**
Gas Breakers	[count]	**5**
Distribution Reclosers	[count]	**404**

Table 5-2: Investment Activities Created from SPS's Data Systems

Measure	Measure Program	Investment Activity Count
Overhead Hardening	Distribution Mainline Overhead Hardening	978
Overhead Hardening	Distribution Lateral Overhead Hardening	10,800
Underground Hardening	Distribution Mainline Underground Hardening	840
Underground Hardening	Distribution Lateral Underground Hardening	5,297
	Total	**17,915**

Figure 5-2: Relative Pole Asset Count Across SPS Service Area



5.2 Substation Asset Register

SPS provided detailed asset register tables for the major substation assets (Breakers, Reclosers and Relays). All the asset classes are listed below in Table 5-3. The asset register tables include equipment type, high-level position within the substation, age, and other attributes. 1898 & Co. leveraged this information to establish additional connectivity within the asset base. Two specific connectivity relationships were developed. The first establishes the link between the distribution protection devices and the breakers from the substation asset register so that accurate customer outage impacts could be established. The second is the relationship between relays and breaker protection. The suitability and required upgrades of the existing equipment to support distribution automation were also evaluated and identified by SPS.

Table 5-3: SPS's Substation Asset Register

Asset Type	Units	Value
Substations	[count]	**365**
Breakers	[count]	461
Reclosers	[count]	86
Relays	[count]	2,878

5.3 Outage Management System

The OMS includes detailed outage information by cause code for each protection device over the last 14 years. The data includes outage causes, durations, CI, CMI, dates, and locations for over 100,000 outage events.

The Integrated Resilience & Risk Investment Model utilized this information to understand the historical storm-related outages for the various distribution laterals and feeders on the system and included MED in the Major Storms Event Database. The OMS data is utilized by the Outage Mitigation Risk & Resilience model to identify outages that can be mitigated by investments in distribution automation.

5.4 Customer Data

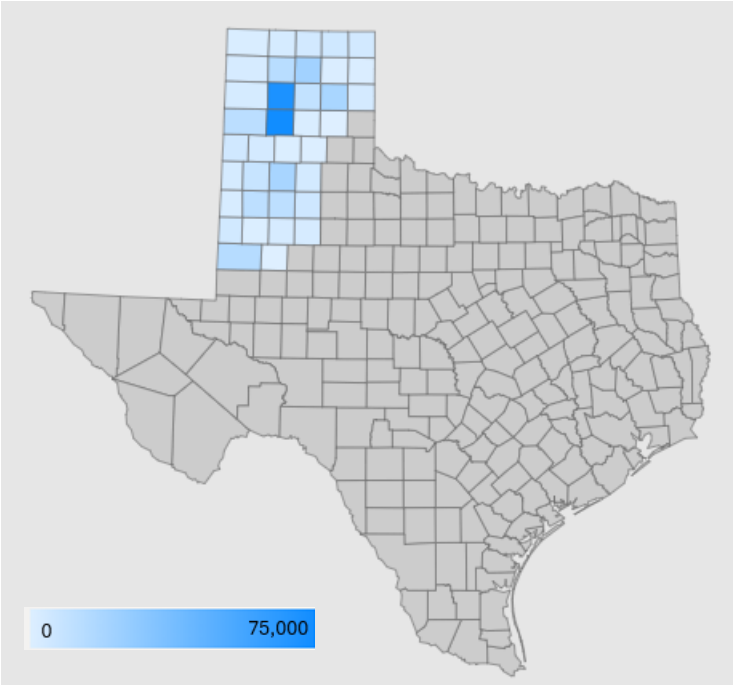
SPS provided customer count and type information with database relationships to the GIS and OMS. Using connectivity from the distribution circuit to the breaker, the customer relationship to the substation was also established. This data allowed the Integrated Resilience & Risk Model to directly link the number and type of customers impacted to each protection device and substation. Types of customers include residential, small C&I, large C&I, and critical customers. This customer information is used in concert with the estimated event and failure duration to estimate the CMI for each investment activity, which is then monetized using the DOE ICE Calculator (see Section 5.5). This is foundational for the customer-centric benefit-cost assessment approach. Table 5-4 provides an overview of the customer count and types across SPS's system.

Table 5-4: SPS's System Wide Metered Customer Breakdown

Customer Type	Customer Count	Percentage
Residential Customers	211,173	79.93%
Small C&I Customers	47,942	18.15%
Large C&I Customers	3,851	1.46%
Critical Customers	1,216	0.46%
Total	264,182	100.0%

Figure 5-3 is a geospatial representation of the location of customers across SPS's service area. The figure shows a heavy representation of customers in the Amarillo urban area of the SPS service area with relatively small customer densities outside this urban area.

Figure 5-3: Relative Customer Count Across SPS's System



As noted above, the approach organized investment activities at the protection zone level. For each protection zone, 1898 & Co. identified the number and type of downstream customers impacted by a failure on that protection zone. This was done by linking the GIS, OMS, and parts of the CIS. Figure 5-4, Figure 5-5, and Figure 5-6 show the customer counts by circuit, mainline, and lateral protection zones, respectively.

Figure 5-4: Customer Count and Type by Circuit

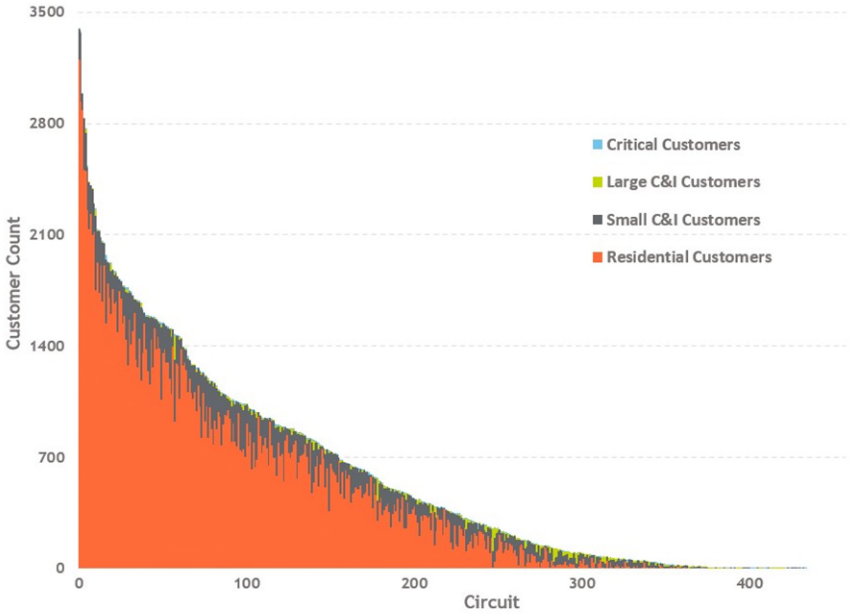


Figure 5-5: Customer Count and Type for Mainline Backbone Protection Zones

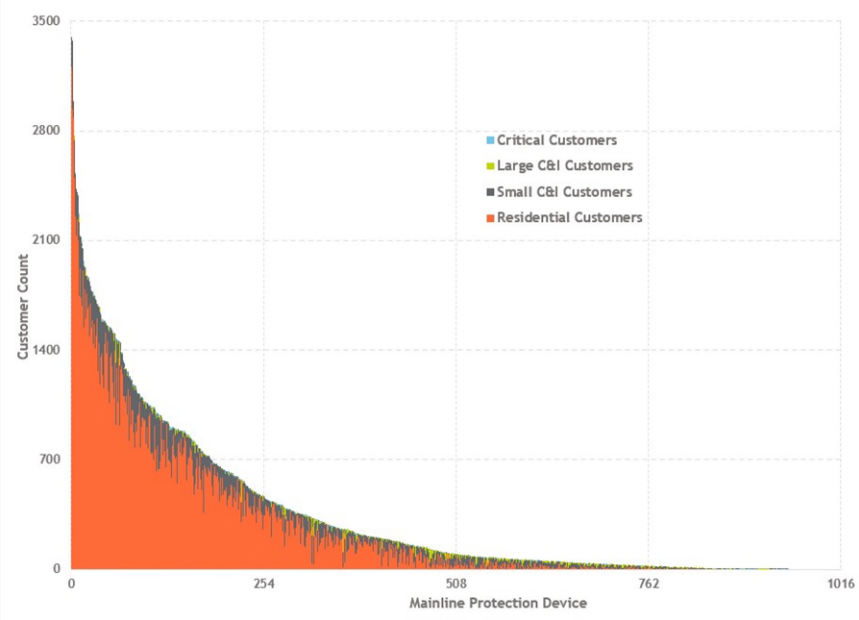
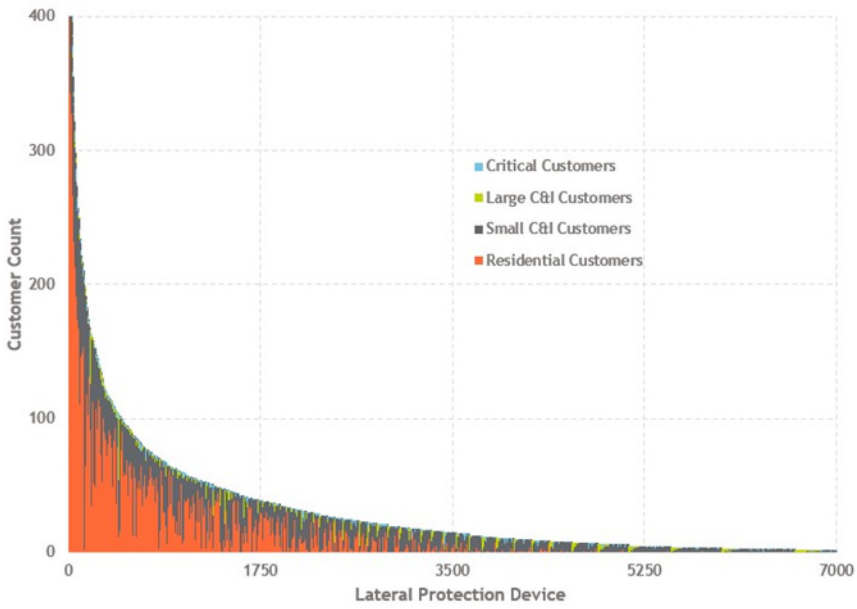


Figure 5-6: Customer Count and Type for Lateral[33] Protection Zones[34]



5.5 ICE Calculator

To monetize the cost of an outage, the benefit-cost evaluation utilizes the ICE Calculator. The ICE Calculator is an electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the DOE.

The value of interruption costs within the calculator is based on customer surveys from 15 research efforts conducted by 10 utility companies, resulting in 34 different data sets and totaling over 105,000 observations from 1989 to 2012. The data sets included over 44,000 Medium to Large C&I customers, 27,000 small C&I customers, and 34,000 residential customers.

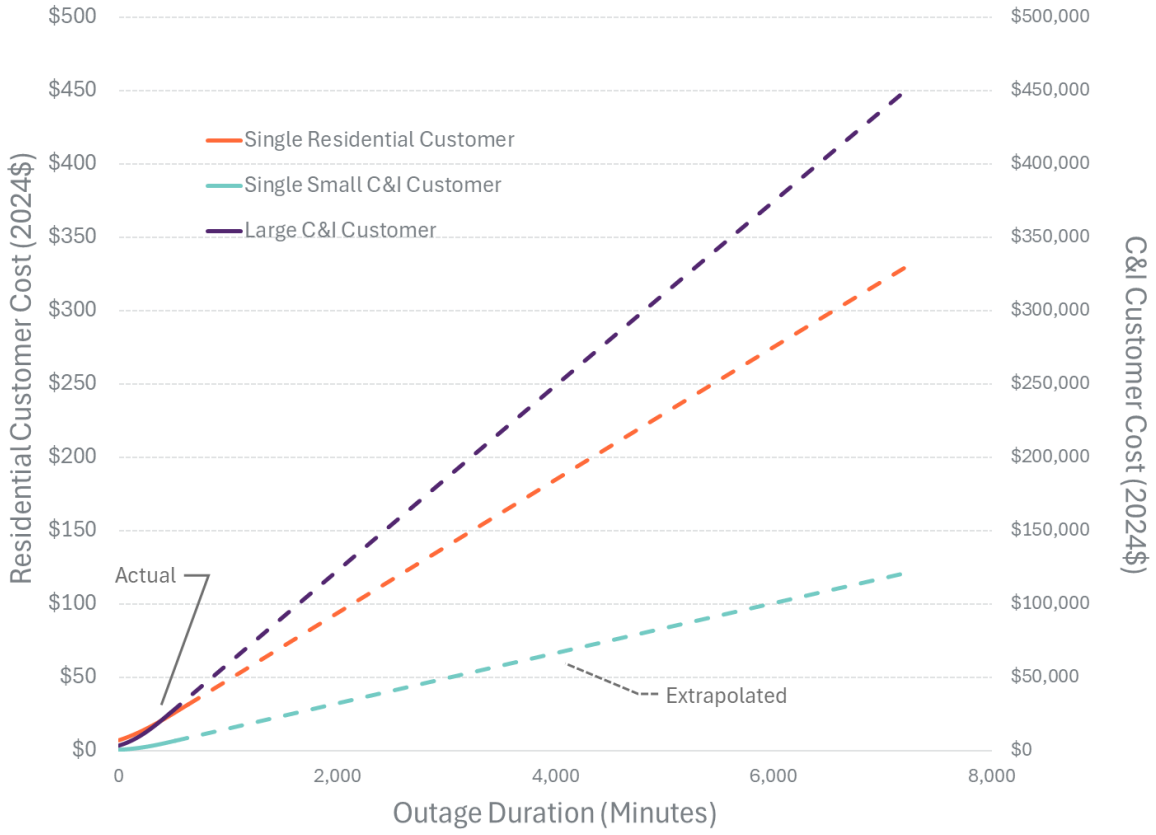
The developers of the ICE calculator have also noted significant advancements in the societal use of electronic devices, in-home life-saving medical devices, and other technologies, including a higher number of people working from home. With most of

[33] Fuse Protection devices
[34] Data truncated for easier readability

the surveys being completed before these advancements, the developers of the ICE Calculator consider the current cost of interruptions for residential customers, as reflected in the ICE Calculator, to be conservative. The developers of the calculator have received additional funding to update the surveys to reflect these key changes, especially the value of residential interruptions in a post-pandemic society.

The calculator includes the estimated interruption costs for residential, small C&I, and large C&I customers for a range of durations. The calculator was extrapolated for the longer durations of storm-based outages. Figure 5-7 shows the cost of interruptions for each class of Texas customers according to the ICE Calculator. The figure also shows the extrapolation for longer outages. Hence, a customer interruption monetized value can be derived for an outage of any duration for each of the listed customer classes.

Figure 5-7: ICE Calculator Monetized Cost of Outage Summary



These indications of outage cost for each customer class are multiplied by the specific customer count and expected duration of each storm for each investment activity to calculate the $CMI at the investment activity level.

As noted above, the values from the ICE Calculator within this benefit-cost assessment are likely conservative given the age of the survey results for residential customers. Due to recent societal changes in patterns of energy consumption for residential customers, the DOE ICE Calculator value of interruptions is likely low for this customer class. The developers of the DOE ICE Calculator expect this value to increase once updated surveys are completed.[35]

5.6 Wildfire Tier

SPS provided 1898 & Co. with a wildfire tier geospatial layer including Tiers 3, 2, and 1. 1898 & Co. mapped each of the assets and protection zones in the GIS to a wildfire tier. Based on this designation, 1898 & Co. mapped potential investment activities investments from Table 5-2 to the appropriate wildfire tier.

5.7 Vegetation Density

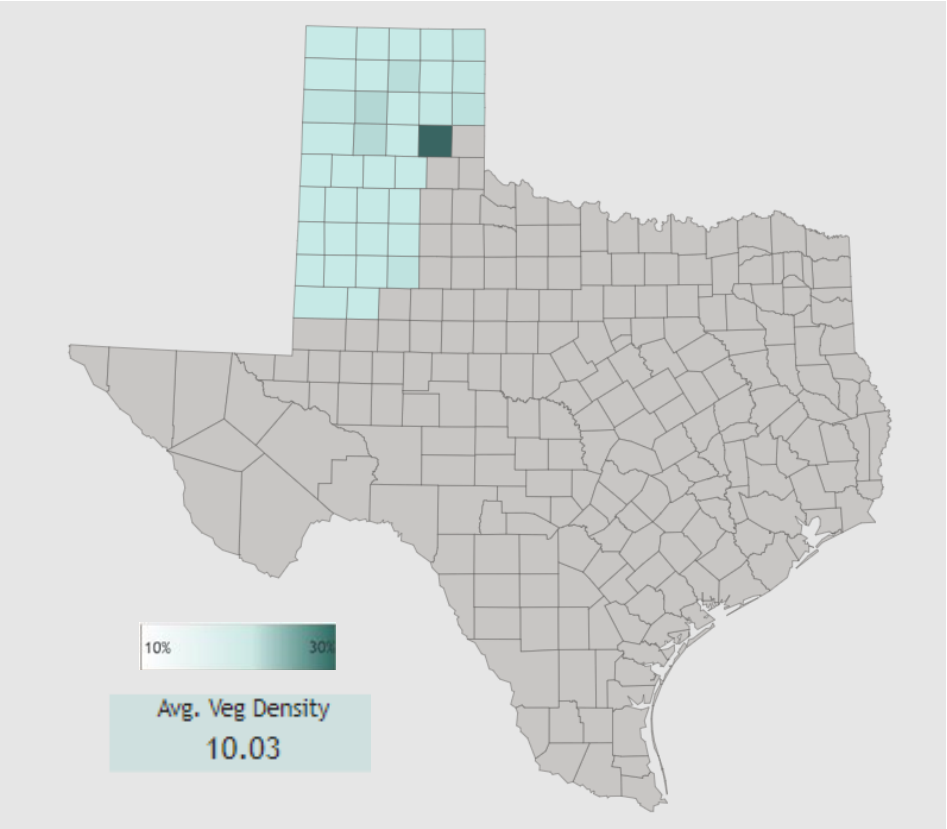
The vegetation density for each overhead conductor is a core data point for identifying and prioritizing resilience investment for circuit assets. This is because vegetation blowing into a conductor (from both inside and outside of the trim zone) is a significant cause of outages during major weather events. The Integrated Resilience & Risk Model estimates the vegetation density around each distribution overhead conductor. The model utilizes satellite tree-canopy data to calculate the percentage of vegetation for 30-meter by 30-meter (900 square-meters) areas across the entire SPS system. The 900-square-meter area is indicative of the vegetation density on the system from a major storm perspective. For each of the approximately 300,000 spans of conductor on SPS's system, a vegetation density is assigned based on the 900-square-meter area(s) the conductor goes through. This information is used to identify

[35] Nexant, Inc. (n.d.). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf. Page 18.

the portions of the system most likely to experience a vegetation-related outage during a resiliency event.

Approximately 99% of the SPS system's protection zones have an average vegetation density of 20% or less. Figure 5-8 illustrates vegetation density by conductor, mapped geospatially across county sections. Notably, SPS experiences low vegetation density throughout its service territory, with the exception of Donley County. This area, while having a higher vegetation density, contains a relatively low number of assets.

Figure 5-8: Relative Vegetation Density across SPS's System

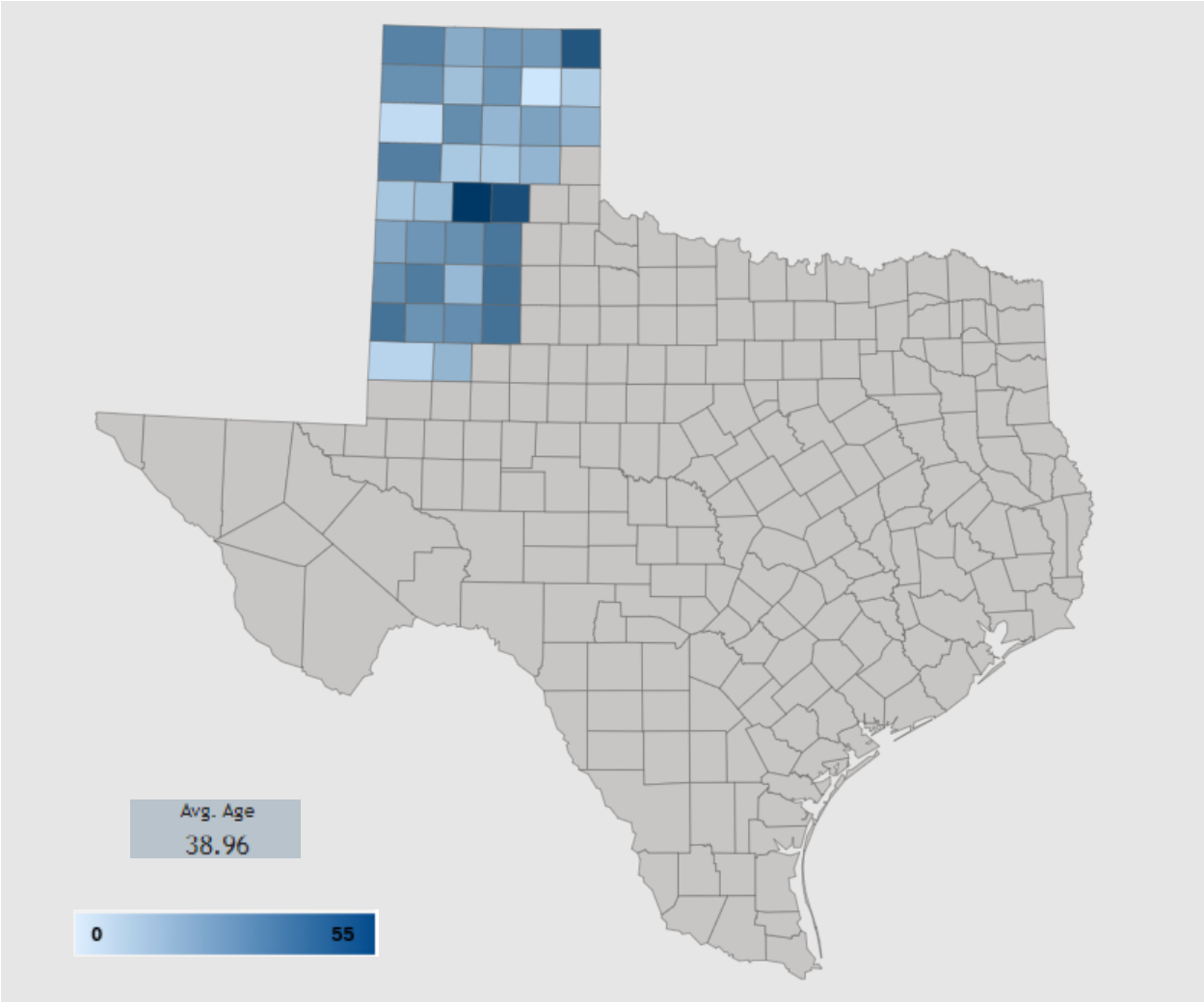


5.8 Age

As assets age, they lose some of their original design strength and capability. For example, aged poles (all else equal) will fail at lower dynamic load levels than poles with their original design strength. The same concept applies to other overhead, underground, and substation assets. 1898 & Co.'s analysis utilized industry-standard survivor curves using an asset class's expected average service life as well as the

specific asset's age to estimate the age-based likelihood of failure during specific events. Ages were extracted from SPS's enterprise data system for the assets that were identified for consideration as part of SPS's SRP. The following figure, Figure 5-9 represents the age distribution of pole assets within the SPS system to represent relative age differences across the service area.

Figure 5-9: Relative Pole Age across SPS's System



5.9 Accessibility

The ability of work crews to access an asset has an impact on the duration of the outage and the cost to restore that part of the system. For example, rear-lot structures take much longer and cost more to restore than front-lot structures. For SPS, many of its infrastructure is in rural areas in fields with minimal access. To take

differences in accessibility into account, the Resilience Event Simulation Model (within the Event Impact Model) performed a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access, while others were designated as in the deep right-of-way (ROW). These designations were used when calculating restoration and resilience investment activity costs in the Integrated Resilience & Risk Investment Model. Based on this analysis, 59% of SPS's system has street access.

6.0 Resiliency Measure Overview

16 TAC § 25.62(c)(2)
Contents of the resiliency plan. The resiliency plan must be organized by measure…

This section organizes the assessment of the major events (Section 3.0), analytics models to evaluate the benefits and effectiveness of resiliency investment activities (Section 4.0), and system vulnerabilities (Section 5.0) by measure. For the quantitatively evaluated measures, a summary of the effectiveness and benefits of the potential investment is provided for each measure. It is from these potential investment activities (organizing activities at the circuit level) that SPS identified and prioritized investments for the SRP.

6.1 Distribution Overhead Hardening Measure

The Distribution Overhead Hardening Measure and Distribution Circuit Protection Hardening Program involve hardening specific sections of distribution circuits in SPS's distribution system to withstand weather-based events by adding and replacing infrastructure to SPS's current hardening standards. The measure also includes wildfire-specific investments to mitigate wildfire risks. As directed by SPS, 1898 & Co. estimated scoping activities for these investments. 1898 & Co. did not evaluate the benefits of these wildfire-specific investment activities; other parts of this filing address the benefits of those activities. The measure includes the following methods from the Resiliency Rule:[36]

(A) hardening electric distribution facilities; and
(B) modernizing electric distribution facilities.

The following sub-section includes:

- A summary description of the measure;
- A review of the resiliency events the measure is expected to mitigate;
- How the Integrated Resilience & Risk Investment Model identified investment activities and estimated their benefits and costs;

[36]Additional methods may apply for investment activities that were not evaluated by 1898 & Co.

- The effectiveness and benefits of potential investment activities; and
- An overview of potential alternative investments.

6.1.1 Measure Description

16 TAC § 25.62(c)(2)
The resiliency plan must be organized by measure, including a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure.

In designing the Distribution Overhead Hardening Measure, SPS considered the following:

- The wide range of resiliency event types, frequencies, and impacts, which pose varied risks to the system across SPS's service area.
- A range of system vulnerabilities, including customer counts and types, infrastructure age and condition, and significant deviations from current design standards. The inherent uncertainty in knowing infrastructure vulnerabilities was incorporated into how this measure has been designed. This is discussed in more detail below.
- The costs of investments to address vulnerabilities and improve the resiliency of infrastructure. This approach included full re-builds to capture vulnerabilities and rebuild entire portions of the distribution system to current hardening standards.

The need to balance these factors guided the structure of the measure. This balancing allows SPS to improve system resiliency for the greatest number of customers while maximizing the effectiveness of resiliency investments. From a high-level perspective, the measure structure is broken into the following activities:

- Hardening vulnerable conductors and equipment in eligible protection zones, including the following:
    - Poles
    - Conductor, including small wire and open wire secondary
    - Line transformers

- Mitigating long span lengths by installing trussing systems on existing distribution poles or installing additional in-line poles, as needed.
- Wildfire specific investment activities including:
    - Wildfire pole wraps
    - Transformer fuse replacements
    - Arrestor replacements

Each of these activities are further described in other parts of SPS's SRP filing. 1898 & Co. estimated the resiliency investment for this program at the overhead protection zone level within SPS's system.

The Resilience Conceptual Framework described in Section 2.2 above is useful in understanding how improvements in system resiliency will manifest under the Distribution Overhead Hardening Measure. This measure is designed to provide resistance improvement, meaning that the hardened infrastructure will be able to withstand stronger stressors before infrastructure failures occur. Figure 6-1 and Figure 6-2 provide a visualization of the expected resiliency improvement with the Distribution Overhead Hardening Measure for a weak and a strong stressor, respectively. In the case of a weak stressor, very few failures of hardened facilities will occur, providing significant improvement for customers. In the case of a strong stressor, failures of hardened facilities will occur less frequently, allowing crews to restore the system more quickly.

Figure 6-1: Resilience Conceptual Framework and Distribution Overhead Hardening Measure – Weak Stressors

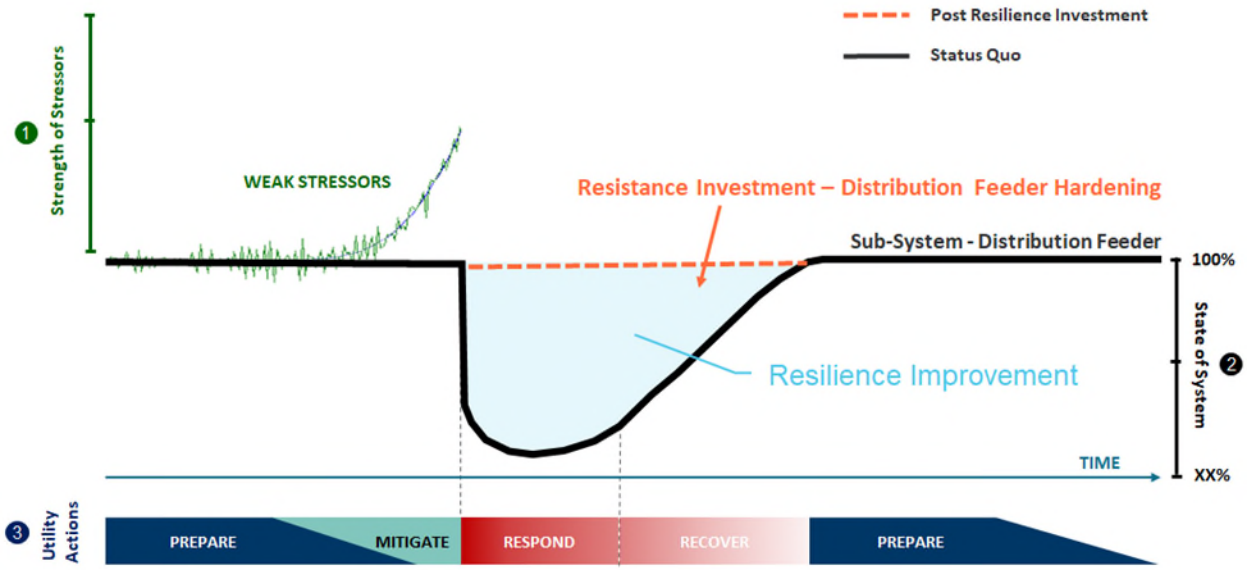
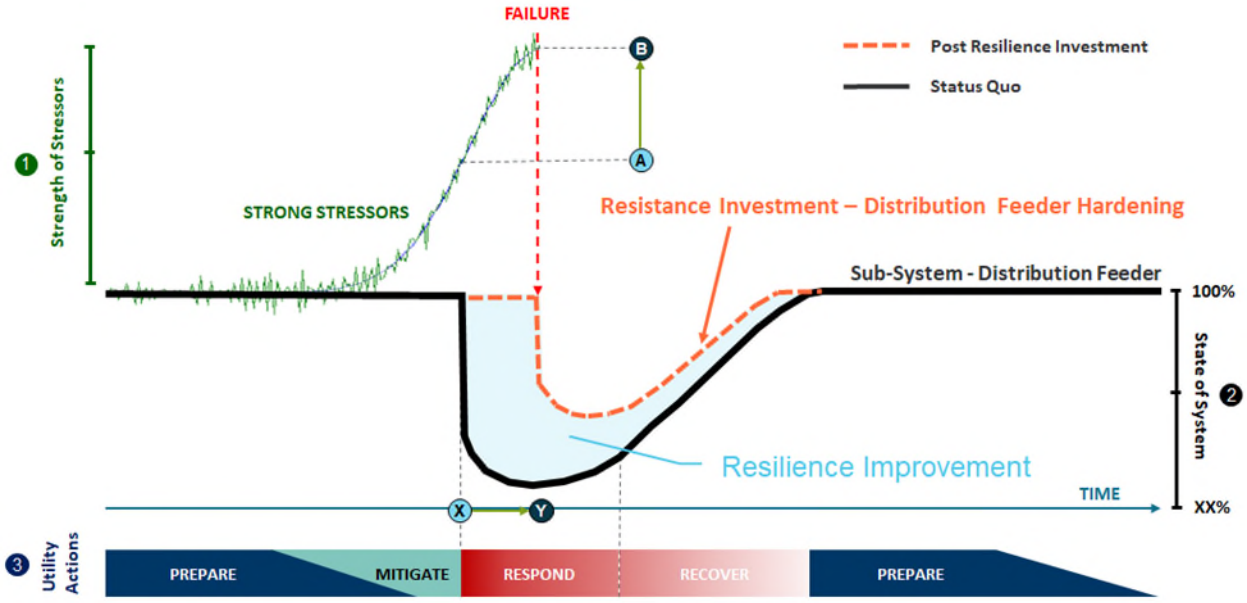


Figure 6-2: Resilience Conceptual Framework and Distribution Overhead Hardening Measure – Strong Stressors



6.1.2 Risk of Events Mitigated by Measure

16 TAC § 25.62(c)(2)(B)(iv)
A resiliency plan must provide sufficient evidence to support the presence of and risk posed by each identified resiliency event.

The distribution overhead system is impacted by nearly every type of weather-based event impacting the SPS service area. See Section 3.0 for additional details on the approach to identify those resiliency events. Section 3.3 outlines the approach to estimate the future frequency and impact of those events on the SPS system. As a summary and for ease of reference, Table 6-1 shows the weather-based resiliency events the Distribution Overhead Hardening Measure is intended to mitigate. Each of these events corresponds to an event listed in Table 3-1. This table includes the definitions for these events.

Table 6-1: Resiliency Events Mitigated by Distribution Overhead Hardening Measure

Extreme Weather	
Wind	**Winter**
1. Thunderstorm Wind	10. Winter Weather
2. Lightning	11. Sleet
3. Hail-Wind	12. Winter Storm
4. High Wind	13. Heavy Snow
5. Strong Wind	14. Ice Storm
Flood	15. Hail-Winter
6. Flood	16. Blizzard
7. Heavy Rain	**Heat**
8. Flash Flood	17. Heat
Tornado	18. Excessive Heat
9. Tornado	**Cold**
	19. Cold/Wind Chill
	20. Extreme Cold/Wind Chill

This measure is designed to withstand and mitigate resiliency events that pose a risk to infrastructure structural vulnerabilities, these include wind, tornado, and winter events. With respect to electrical vulnerabilities, reconductoring will mitigate heat and cold events. Importantly, the NOAA classification of events is based on the main driver of the event, but these events often involve other weather conditions. For

instance, during some flooding events, winds are also present that may cause infrastructure failures. Similarly, tornados are often accompanied by rain and surrounding winds. While this measure can mitigate or withstand the impacts of the surrounding winds, it cannot withstand the impact from the direct path of a tornado.

6.1.3 Systematic Approach to Estimate Investment Activities, Cost & Benefits

16 TAC § 25.62(c)(2)(E)
A resiliency plan must be implemented using a systematic approach over a period of at least three years. The resiliency plan must explain this systematic approach and provide implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments. The resiliency plan should identify relevant cost drivers (e.g., line miles, frequency of inspections, frequency of trim cycles, etc.) that would affect the estimates.

Based on the discussion in the previous sections, this section summarizes the systematic approach 1898 & Co. employed to identify investment activities for the measure and estimate their expected costs and benefits. Section 7.2 includes the systematic approach to organize the initial investment activities and measures into the set of executable investment activities that are included within the SRP.

- **Investment Activity Identification**: Section 4.0 describes the approach to identify potential investment activities included within this measure. As a summary, the investment activity includes all the assets within a protection zone that do not meet the current hardening standard. The evaluation assumes that SPS will exclude assets that meet the hardening standard upon field surveys during the planning and engineering of the projects. 1898 & Co. utilized data from the GIS to determine the number of poles, crossarms (which include insulators), transformers, and spans of conductor within each protection zone (see Section 5.1). The evaluation also determined if the infrastructure was in urban, suburban, or rural areas and if the infrastructure had road access or not (see Section 5.9). To identify long spans, 1898 & Co.

utilized the GIS and the distance between poles estimate how many new poles would need to be added within each protection zone.

- **Investment Activity Cost Estimation**: The costs of the Distribution Overhead Hardening Measure are based on historical pole, transformer, and conductor replacement costs (which include both materials and labor) provided by SPS to meet the current hardening standard. The costs include various multipliers for accessibility. The cost of a project is the sum of: (1) the pole quantity multiplied by the cost per pole, (2) the line transformer quantity multiplied by the cost per transformer, and (3) the conductor length in feet multiplied by the conductor cost per foot.
- **Estimating Quantified Benefits**: 1898 & Co. utilized the Integrated Resilience & Risk Investment Model to perform a quantified benefits evaluation for this measure. Figure 2-4 includes the application of the resiliency and risk-based planning approach for this measure. The figure shows the alignment between resiliency events, the analytics models used to identify investment activities, and the benefits methodology to understand the effectiveness of the investment activities. The BCR is a key value used in the selection and prioritization of investment activities in the plan.

As the figure shows, this measure utilizes two of the analytics models to estimate the quantified benefits and effectiveness for each investment: the Resilience Event Simulation approach and Equipment Failure Resiliency & Risk Mitigation approach. See Section 4.1 and Section 4.3 for a description of these two approaches. This measure was evaluated at the protection zone level to closely align the infrastructure resiliency activity and quantified customer benefit.

While estimating the investment activity scope and cost for the weather resiliency portion of these measures, 1898 & Co., at the direction of SPS, estimated the scope and cost of the wildfire-specific activities for each potential investment. This was done in alignment to SPS standards and for execution synergies to allow SPS to more efficiently deploy both weather resiliency and wildfire resiliency investment activities concurrently on the system. Specifically, 1898 & Co. utilized the GIS data to estimate

the activity scope and costs of adding pole wraps, replacing transformer fuses, and replacing arrestors, based on counts in the GIS and unit costs provided by SPS.

6.1.4 Evidence of Effectiveness and Benefits

16 TAC § 25.62(c)(2)(A)

(ii) The resiliency plan must include evidence of the effectiveness of the measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the identified resiliency event. The commission will give greater weight to evidence that is quantitative, performance-based, or provided by an independent entity with relevant expertise.

(iii) A resiliency plan must explain the expected benefits of the resiliency measures including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers. and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations.

1898 & Co. evaluated this measure comprehensively across the entire SPS overhead distribution system. Approximately 11,793 protection zones were evaluated. This section presents the quantified benefit results from the analytics models, including the weather-based resiliency benefits and costs. Any costs for wildfire-specific activities are excluded from the results presented in this section. These results align with the Resiliency Rule sections identified above, measuring benefits in terms of avoided restoration costs and customer outages.

SPS intends to execute this measure by grouping work such that identified protection zones on a circuit will be hardened together. This reduces the chances that SPS will have to come back to a circuit or area multiple times to perform resiliency work.

The quantified benefits results are presented at the protection zone level, however, for ease of representing this level of information, the quantified benefit results are shown on a percentile ranking basis. The ranking is based on the Resilience & Risk BCR.

Figure 6-3 includes the expected avoided customer outage benefits for the Distribution Overhead Hardening Measure. The figure includes the absolute benefit in CMI from the NOAA and reliability events as well as the percentage improvement. The figure also shows that approximately 20% of protection zones have quantified benefits

in excess of cost. For these investment activities, the evaluation shows expected improvement in CMI of approximately 54%, ranging from 47% to 57%.

Figure 6-3: Distribution Overhead Hardening Measure Avoided Customer Outage Benefit

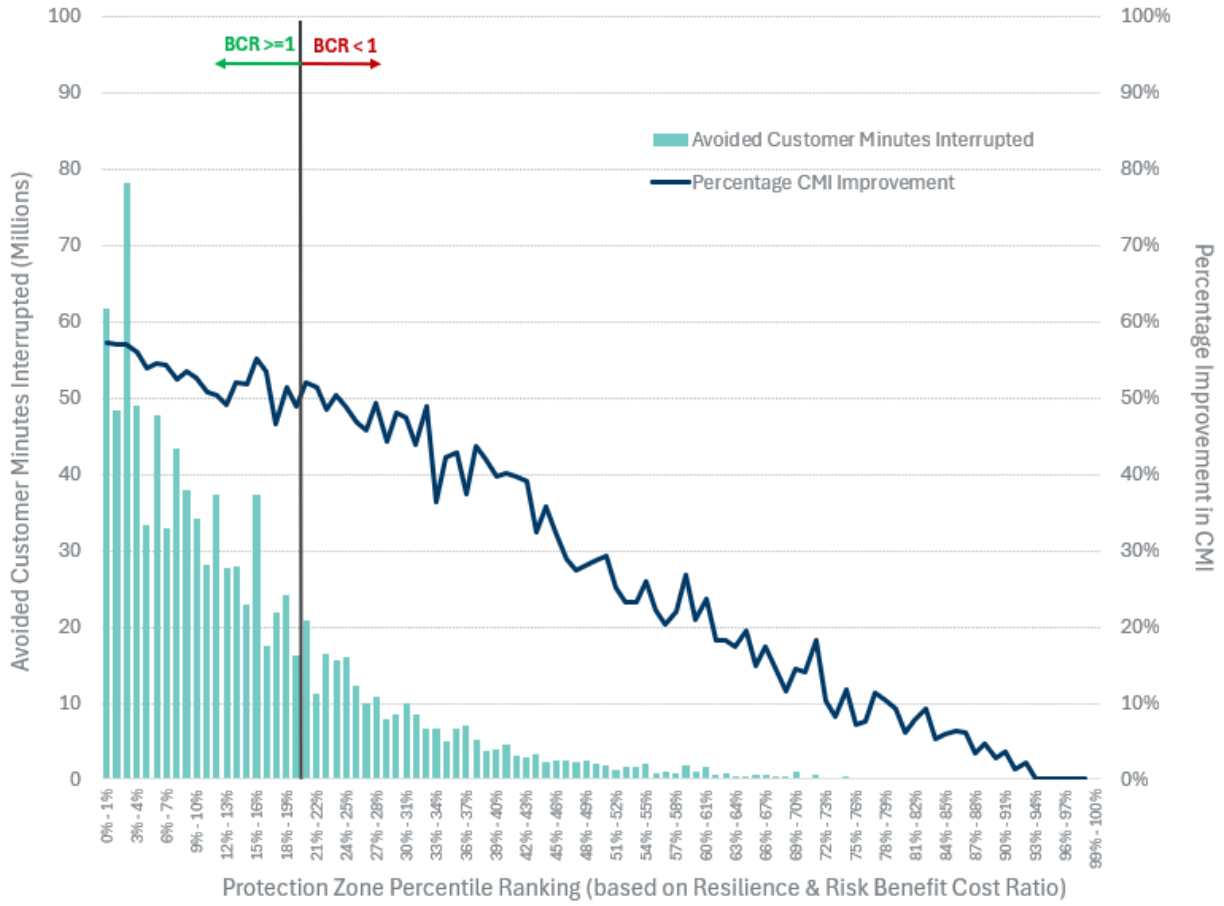


Figure 6-4 takes the CMI benefits from Figure 6-3, applies the modified DOE ICE Calculator (see Section 5.5) to monetize the outages, and adds the avoided restoration costs for each protection zone. The application of the ICE Calculator incorporates the various customer types, including critical customers, into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. As the figure shows, most of the quantified benefits are from avoided customer outages. The figure also shows the expected improvement in monetized customer outages and restoration costs. The protection zones with a positive BCR show an improvement in monetized customer outages of approximately 49%, ranging

from 38% to 51%, and approximately 76% for restoration costs, with values ranging from 74% to 77%.

Figure 6-4: Distribution Overhead Hardening Measure Benefits Summary

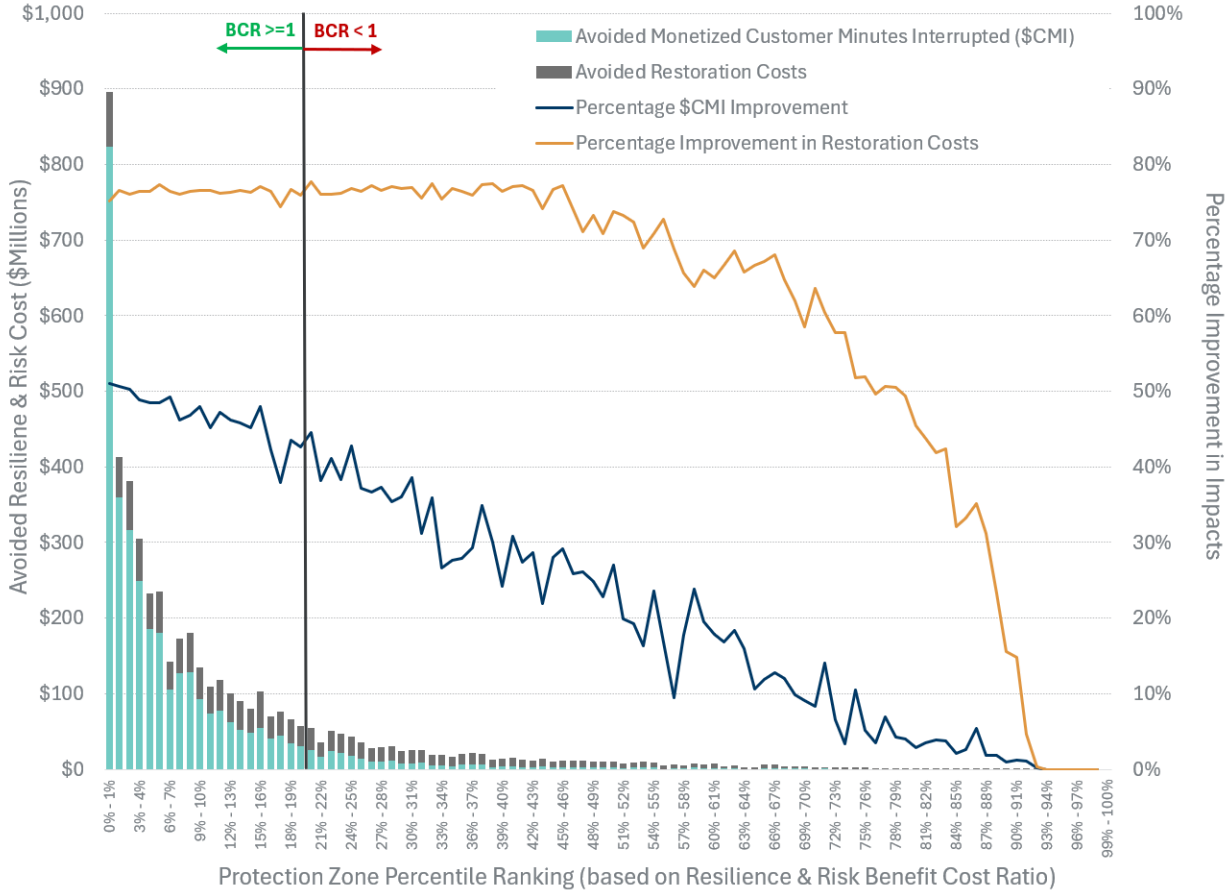
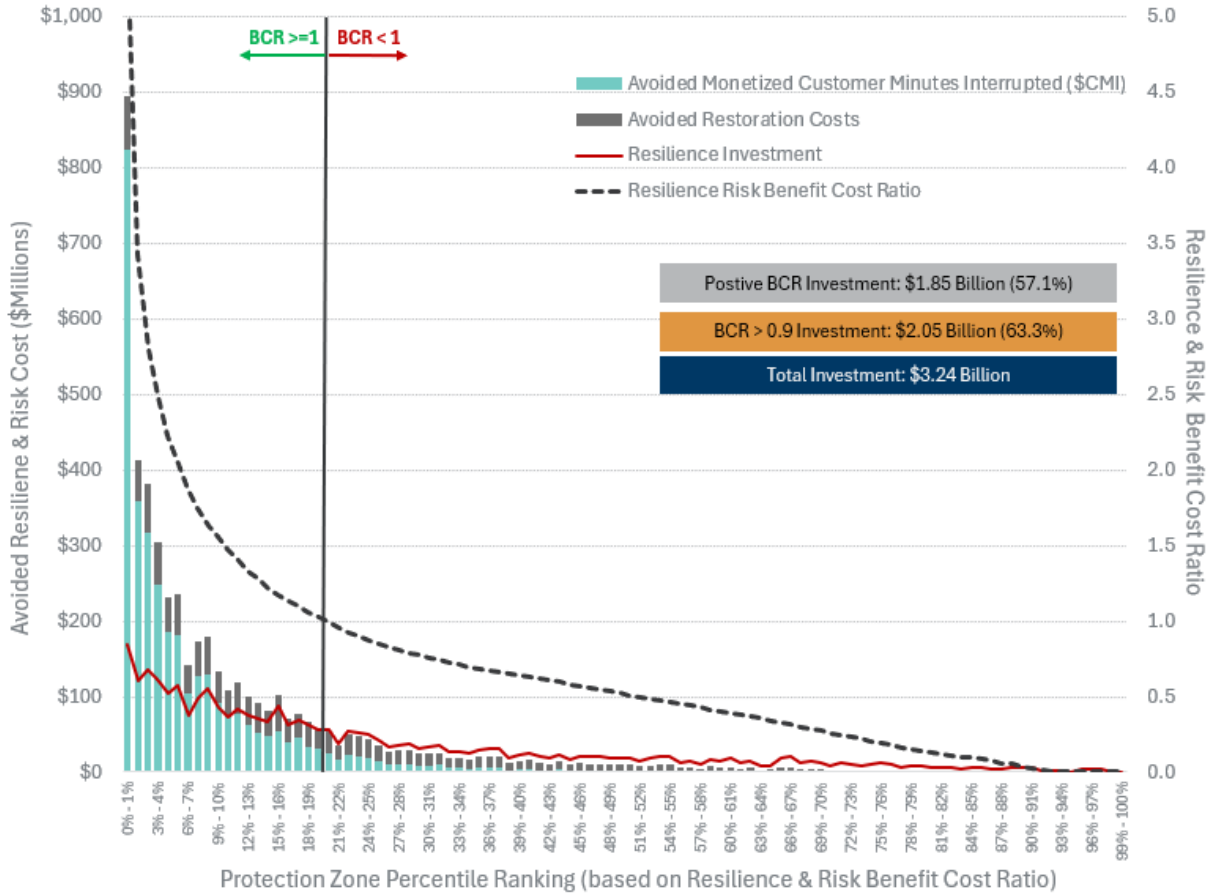


Figure 6-5 takes the benefit results from Figure 6-4 and layers in the expected resiliency investment for each protection zone to show the Resiliency & Risk BCR. As the figure shows, if this program were applied to the entire SPS distribution system, the overall investment level would be approximately $3.2 billion. Approximately $1.8 billion, or 57% of the total potential investment level, has quantified benefits in excess of cost.

Figure 6-5: Distribution Overhead Hardening Measure Resiliency & Risk BCR Summary

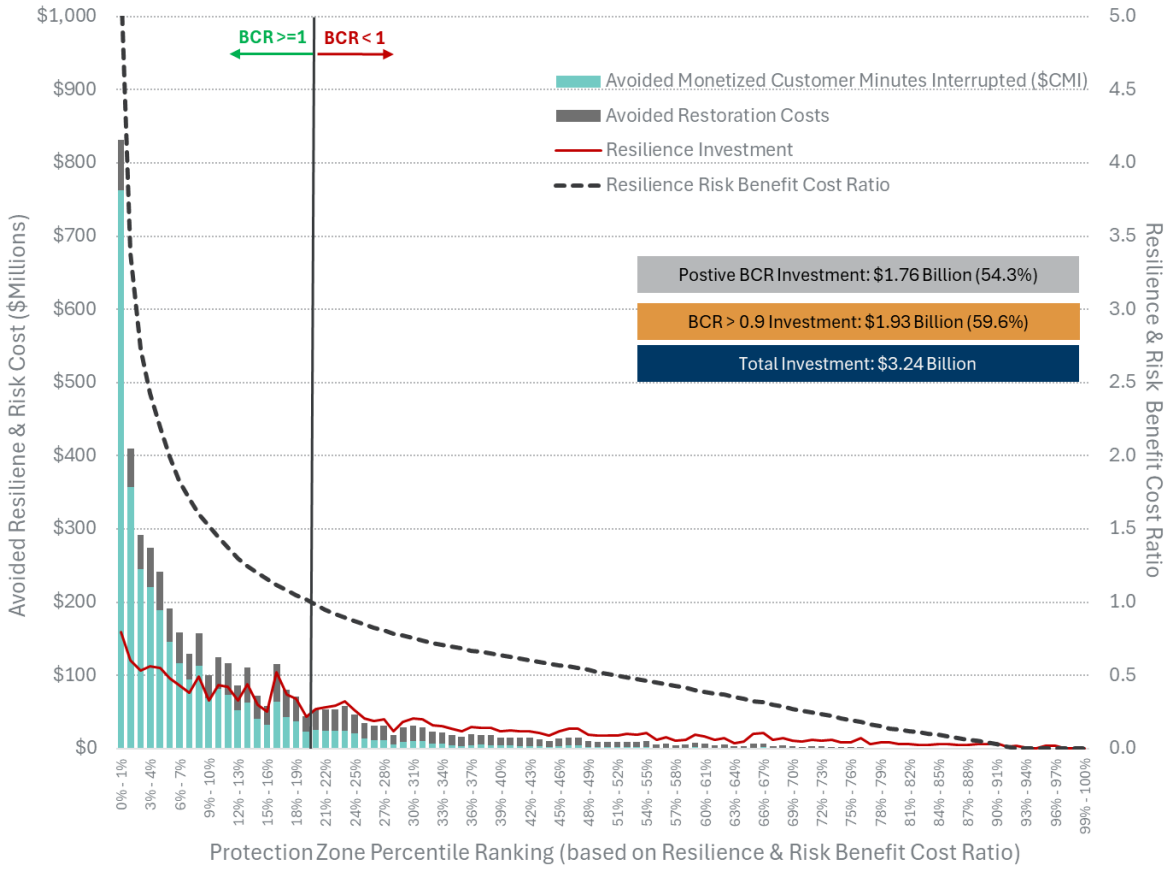


The results presented above assume no other measures are implemented and are based on the current protection system state, including the current level of deployment of distribution automation. Section 6.2 outlines the Distribution System Protection Modernization Measure. Protection modernization changes the number of customers impacted by asset failures. For example, a circuit backbone may only be protected by the substation breaker with 1,500 downstream customers. In that case, any asset failure on the backbone would cause 1,500 customers to be without service. However, if the Mainline Automated Reclosing Deployment Program from the Distribution System Protection Modernization Measure is deployed on this circuit, fewer customers would be impacted by the same asset failure. Since SPS intends to deploy the Mainline Automated Reclosing Deployment Program across the system at scale, 1898 & Co. performed the resiliency and risk modeling for this measure

assuming that the automated reclosing program was implemented on all circuits to avoid double counting of benefits-cost results.

Figure 6-6 shows the updated BCR results of the Distribution Overhead Hardening Measure if the Mainline Automated Reclosing Deployment Program is implemented across the entire SPS system. As the figure shows, most of the benefits are from avoided customer outages, and the total potential investment level would be approximately $3.24 billion. Approximately $1.76 billion, or 54.3%, of the total potential investment level has quantified benefits in excess of cost. These investments have approximately $3.66 billion of total benefits for a total BCR of 2.08.

Figure 6-6: Distribution Overhead Hardening Measure Resiliency & Risk BCR Summary Assuming Mainline Automation on All Circuits



6.1.5 Reasonable Alternatives Review

16 TAC § 25.62(c)(2)(A)(v)
The resiliency plan must explain the selection of each measure over any reasonable and readily-identifiable alternatives. The resiliency plan must contain sufficient analysis and evidence, such as cost or performance comparisons, to support the selection of each measure. In selecting between measures, whether a measure would support the plan's systematic approach may be considered

As an alternative to the Distribution Overhead Hardening Measure, 1898 & Co. evaluated an overhead-to-underground conversion alternative. This evaluation was performed at the protection zone level for over 11,790 protection zones, utilizing the Integrated Resilience & Risk Investment Model. The evaluation showed that only 1 protection zone of the 11,790 evaluated had a greater BCR for the overhead to underground alternative. **Based on this, 1898 & Co. considers overhead hardening as the preferred approach.**

6.2 Distribution System Protection Modernization Measure

The Distribution System Protection Modernization Measure includes investment in smart and connected protection devices to minimize the impact of disruptive events. The measure also includes wildfire-specific investments to mitigate wildfire risks. As directed by SPS, 1898 & Co. estimated scoping activities for these investments. 1898 & Co. did not evaluate the benefits of these wildfire-specific investment activities. Other parts of this filing review the benefits of those activities. This measure includes the following resiliency methods from the Resiliency Rule:[37]

> (B) modernizing electric distribution facilities.

The following sub-section includes:

- A summary description of the measure;
- A review of the events the measure is expected to mitigate;
- How the Integrated Resilience & Risk Investment Model identified investment activities and estimated their benefits and costs;
- The effectiveness and benefits of potential investment activities; and
- An overview of potential alternative investments.

[37]Additional methods may apply for investment activities that were not evaluated by 1898 & Co.

6.2.1 Measure Description

16 TAC § 25.62(c)(2)
The resiliency plan must be organized by measure, including a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure.

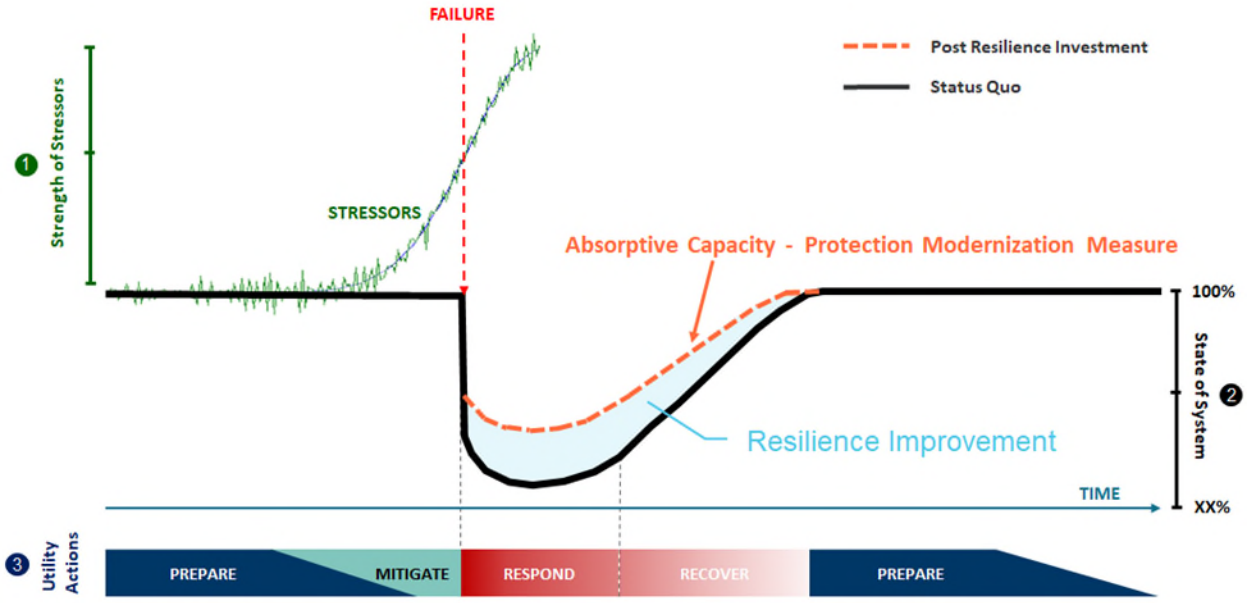
In designing the Distribution System Protection Modernization Measure, SPS considered the current state of the protection system and the desired future state. The desired future state includes full automation for a "self-healing" concept, often referred to as "distribution automation," to temporarily transfer customer load to adjacent circuits using an advanced distribution management system and enhanced communications. SPS has already invested in the advanced distribution management system. This measure includes another foundational investment toward that desired state. Specifically, installing modern, communications-enabled protection devices on each circuit. The measure is broken into the following programs:

- **Program 1: Mainline Automated Reclosing Deployment** – This program includes the deployment of mainline reclosers, breakers, relays, and the controls necessary to increase sectionalization and enable automated feeder switching. When an outage event occurs, sectionalization minimizes the downstream customers initially impacted. Automated feeder switching then reconfigures the system to minimize downtime for those customers who experience the outage.
- **Program 2: Lateral Reclosing Deployment** – This program includes installation of lateral reclosers where fuses are currently located. This program minimizes the customer impact of nuisance events. Nuisance events occur when the electrical system is temporarily disrupted, often by a tree branch slapping the line or similar temporary contact. Without a reclosing device, these events would cause a sustained outage. With a lateral recloser in place, the reclosing action causes customers to experience 'blinks' or minor disruptions in service.

The Resilience Conceptual Framework described in Section 2.2 above is useful in understanding the expected improvement in system resiliency with the Distribution System Protection Modernization Measure. While the Distribution Overhead Hardening

measure is designed to provide resistance improvement by having less infrastructure failures, this measure is designed to improve absorptive capacity by decreasing the absolute impact of infrastructure failures. Absorptive capacity improvements do not decrease the number of failures, rather they decrease the impact of those failures. Figure 6-7 provides a visualization of this absorptive capacity and the expected resiliency improvement with the Distribution System Protection Modernization Measure.

Figure 6-7: Resilience Conceptual Framework and Distribution System Protection Modernization Measure



6.2.2 Risk of Events Mitigated by Measure

16 TAC § 25.62(c)(2)(B)(iv)
A resiliency plan must provide sufficient evidence to support the presence of and risk posed by each identified resiliency event.

Similar to the Distribution Overhead Hardening Measure, the Distribution System Protection Modernization Measure is designed to mitigate the impact of nearly every weather-based event impacting the SPS service area. See Section 3.0 for additional details on the approach to identify those resiliency events. Section 3.3 outlines the approach used to estimate the future frequency and impact of those events on the SPS system. As a summary and for ease of reference, Table 6-2 shows the resiliency

events the Distribution System Protection Modernization Measure is intended to mitigate. Each of these events corresponds to an event listed in Table 3-1, which provides the definitions for these events.

Table 6-2: Resiliency Events Mitigated by Distribution System Protection Modernization Measure

Extreme Weather	
Wind	**Winter**
1. Thunderstorm Wind	10. Winter Weather
2. Lightning	11. Sleet
3. Hail-Wind	12. Winter Storm
4. High Wind	13. Heavy Snow
5. Strong Wind	14. Ice Storm
Flood	15. Hail-Winter
6. Flood	16. Blizzard
7. Heavy Rain	**Heat**
8. Flash Flood	17. Heat
Tornado	18. Excessive Heat
9. Tornado	**Cold**
	19. Cold/Wind Chill
	20. Extreme Cold/Wind Chill

This measure will mitigate the risks to both structural and electrical vulnerabilities on the system. Additionally, as noted above, the NOAA classification of events is based on the main driver of the event, and these events involve other weather conditions. For instance, with some flooding events, winds are also present that may cause infrastructure failures. Similarly, tornados are often accompanied by rain and surrounding winds. While this measure can mitigate or withstand the impacts of the surrounding winds, it cannot withstand the impact from the direct path of a tornado. For other major events, such as an ice storm with ice-thickness over an inch across major sections of the SPS service territory, this measure may be less effective, since the event could cause failures on the adjacent circuits and reduce the ability to temporarily transfer customer load. This same issue applies to all larger events.

6.2.3 Systematic Approach to Estimate Investment Activities, Cost & Benefits

16 TAC § 25.62(c)(2)(E)
A resiliency plan must be implemented using a systematic approach over a period of at least three years. The resiliency plan must explain this systematic approach and provide implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments. The resiliency plan should identify relevant cost drivers (e.g., line miles, frequency of inspections, frequency of trim cycles, etc.) that would affect the estimates.

This section outlines the systematic approach 1898 & Co. employed to identify investment activities for the measure and estimate their expected costs and benefits. Section 7.2 includes the systematic approach used to organize the initial investment activities, programs, and measures into executable investment activities that are included within the SRP. The following sub-sections summarize the approach utilized to identify investment activities and estimate their cost:

Program 1: Mainline Automated Reclosing Deployment

- **Investment Activity Identification**:
  - **Replacement of Existing non-standard Reclosers**: SPS's existing system includes reclosers without sufficient automation and control capabilities (RV, V6H, WV, etc.). To enable full automation and remote communications capabilities, these devices need to be replaced. Based on the designations SPS provided, 1898 & Co. identified from GIS and the OMS data the number of existing devices on each circuit to be replaced with modern communication-enabled reclosing devices.
  - **Additional Mainline Reclosers**: 1898 & Co. estimated the number of mainline reclosers to add to each circuit. As noted in Section 4.2.2.1, the Outage Mitigation Resilience and Risk analytics model identifies the number of additional mainline reclosers to maximize customer benefit, specifically identifying where the incremental benefits of adding another recloser exceed the incremental cost of that reclosers. Some of SPS's mainline

circuits in rural locations are long. For these circuits, a minimum of 1 mainline recloser per 10 primary line miles was included in accordance with the current SPS standard. 1898 & Co. also included the replacement of manual tie switches with reclosers to enable automation functionality with adjacent circuits.

- **Recloser Controllers**: SPS's existing system includes reclosers without sufficient communications control capabilities (Form 4c, Form 3, etc.). 1898 & Co estimated the number of communication controller upgrades necessary to enable localized communications of devices on the system for each circuit
- **Substation Circuit Relays and Breakers Replacements**: For each circuit, SPS provided guidance to estimate the count and cost of devices necessary to support the distribution automation communications requirements. 1898 & Co. estimated the counts and costs for these devices, and SPS verified the result.

- **Investment Activity Cost Estimation**: SPS provided 1898 & Co. with unit costs, including materials and labor, for each activity above. Based on these unit costs, 1898 & Co. multiplied the unit costs by each investment activity to estimate the costs for each investment activity by circuit.

Program 2: Lateral Reclosing Deployment

- **Investment Activity Identification:** 1898 & Co. identified fuse locations for upgrade to a lateral recloser where no downstream assets are located within WSO Tier 2 or Tier 3 areas, as directed by SPS. If a fuse has downstream assets in Tier 2 or Tier 3 areas, it is *not* eligible for upgrade to a lateral reclosing device.
- **Investment Activity Cost Estimation**: Lateral reclosers are installed for each phase of conductor. SPS provided 1898 & Co. with a unit cost per phase, including materials and labor. Based on the number of fuse locations identified for each circuit, 1898 & Co. estimated the total cost to install lateral reclosers for each circuit.

Estimating Quantified Benefits

1898 & Co. utilized the Integrated Resilience & Risk Investment Model to perform a quantified benefits evaluation for both programs included in the Distribution System Protection Modernization Measure. Figure 2-3 includes the application of the resiliency and risk-based planning approach for the measure. The figure shows the alignment between resiliency events, the analytics models used to identify investment activities, and the benefits methodology to understand the effectiveness of the investment activities. The BCR is a key value used in the selection and prioritization of investment activities in the plan. As the figure shows, this measure utilizes two approaches to estimate benefits and effectiveness for each investment. Additionally, the figure shows the complex nature of modeling this measure, with linkage to nearly every event (as discussed above), several activities within the Outage Mitigation Resiliency & Risk approach, and several equipment types for the Equipment Failure Resilience & Risk Mitigation approach.

There are three benefit streams for the Distribution System Protection Modernization Measure. First, it provides additional sectionalization of circuit mainlines so that fewer customers experience an outage when an event occurs. Second, automated feeder transfer schemes minimize customer downtime during disruptive events. Third, lateral reclosers avoid sustained outages from nuisance events. Section 4.2.2.1 describes how these benefits are estimated.

Estimating Wildfire Investment Activity Scope & Cost

While estimating the investment activity scope and cost for the weather resiliency portion of these measures, 1898 & Co., at the direction of SPS, estimated the scope and cost of the wildfire-specific activities for each potential investment. This was done in alignment to new SPS standards and for execution synergies to deploy both weather resiliency and wildfire resiliency investment activities concurrently on the system. Specifically, 1898 & Co. Estimated the activity level and costs of installing fault indicators and replacing arrestors based on counts in the GIS and unit costs provided by SPS.

6.2.4 Evidence of Effectiveness and Benefits

16 TAC § 25.62(c)(2)(A)

(ii) The resiliency plan must include evidence of the effectiveness of the measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the identified resiliency event. The commission will give greater weight to evidence that is quantitative, performance-based, or provided by an independent entity with relevant expertise.

(iii) A resiliency plan must explain the expected benefits of the resiliency measures including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers. and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations.

6.2.4.1 Program 1: Mainline Automated Reclosing Deployment

1898 & Co. evaluated this program comprehensively across the entire SPS distribution system for approximately 459 circuits. This section presents the quantified benefit results from the analytics models, which include only the weather-based resiliency benefits and costs. Any costs for wildfire-specific activities are excluded from the results presented in this section. These results align with the Resiliency Rule sections identified above, measuring benefits in terms of avoided restoration costs and avoided customer outages. The quantified benefits results are presented at the circuit level, however, for ease of representing this level of information, the quantified benefit results are shown as a percentile ranking, based on the Resilience & Risk BCR.

Figure 6-8 shows the expected avoided customer outage benefits for the Mainline Automated Reclosing Deployment program that is a part of the Distribution System Protection Modernization Measure. The figure includes the absolute benefit in CMI from the NOAA and reliability events, as well as the percentage improvement. The figure also shows that approximately 31% of the mainline circuits have quantified benefits in excess of cost. For these investment activities, the evaluation shows an expected improvement in CMI of approximately 38%, ranging from 11% to 57%.

Figure 6-8: Mainline Automated Reclosing Deployment Program Avoided Customer Outage Benefit

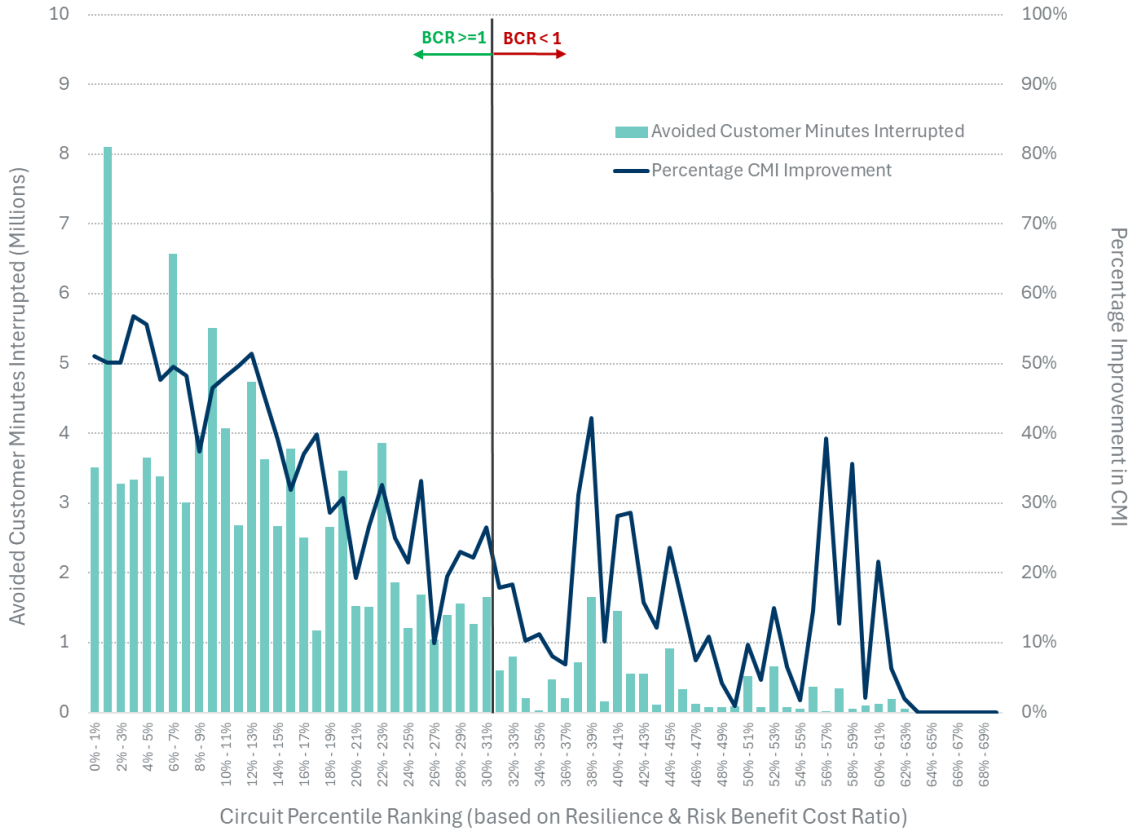
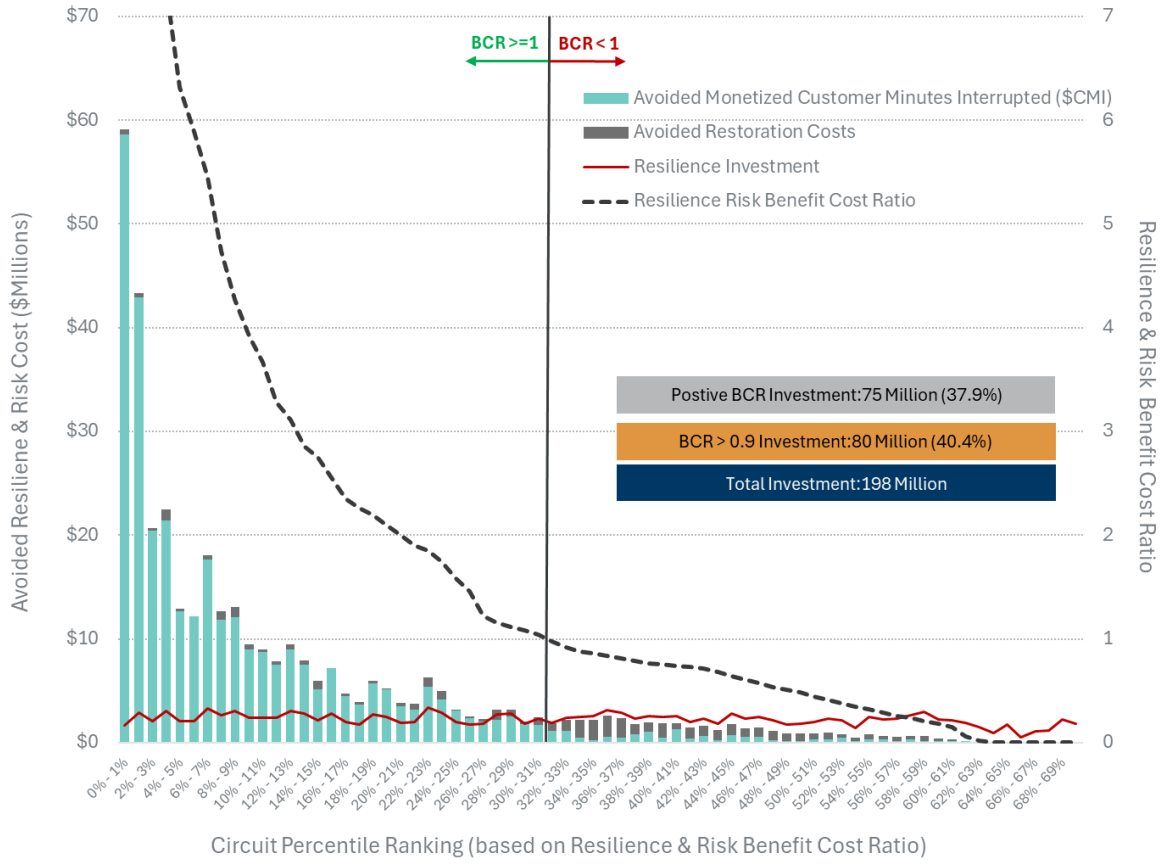


Figure 6-9 takes the CMI benefits from Figure 6-8 and applies the modified DOE ICE Calculator (see Section 5.5) to monetize the outages, adds the avoided restoration costs for each circuit, and includes the expected resiliency investment for each circuit to show the Resiliency & Risk BCR. The circuits are ranked from highest to lowest in terms of BCR. The figure shows most of the quantified benefits are from avoided customer outages. If this program were applied to the entire SPS distribution system, the overall investment level would be approximately $198 million. Approximately $75 million, or 38% of the total potential investment level, has quantified benefits in excess of cost. These investments with a BCR >= 1 have total quantified benefits of approximately $330 million for a total BCR of 4.3.[38]

[38] Excludes Communication Modernization measure. The impact of this investment on the BCR is discussed in Section 6.3.3

Figure 6-9: Mainline Automated Reclosing Deployment Program Resiliency & Risk BCR Summary



6.2.4.2 *Program 2: Lateral Reclosing Deployment*

1898 & Co. evaluated this program comprehensively across the entire SPS distribution system at the circuit level. This section includes the quantified benefit results from the analytics models. These results align with the Resiliency Rule sections identified above, measuring benefits in terms of avoided restoration costs and avoided customer outages. The quantified benefits results are presented at the circuit level, however, for ease of representing this level of information, the quantified benefit results are shown as a percentile ranking, based on the Resilience & Risk BCR.

Figure 6-10 presents the expected avoided customer outage benefits for the Lateral Reclosing Deployment program that is a part of the Distribution System Protection Modernization Measure, including the absolute benefit in CMI from the NOAA and

reliability events. The figure also shows that approximately 4% of protection zones have quantified benefits in excess of cost.

Figure 6-10: Lateral Reclosing Deployment Program Avoided Customer Outage Benefit

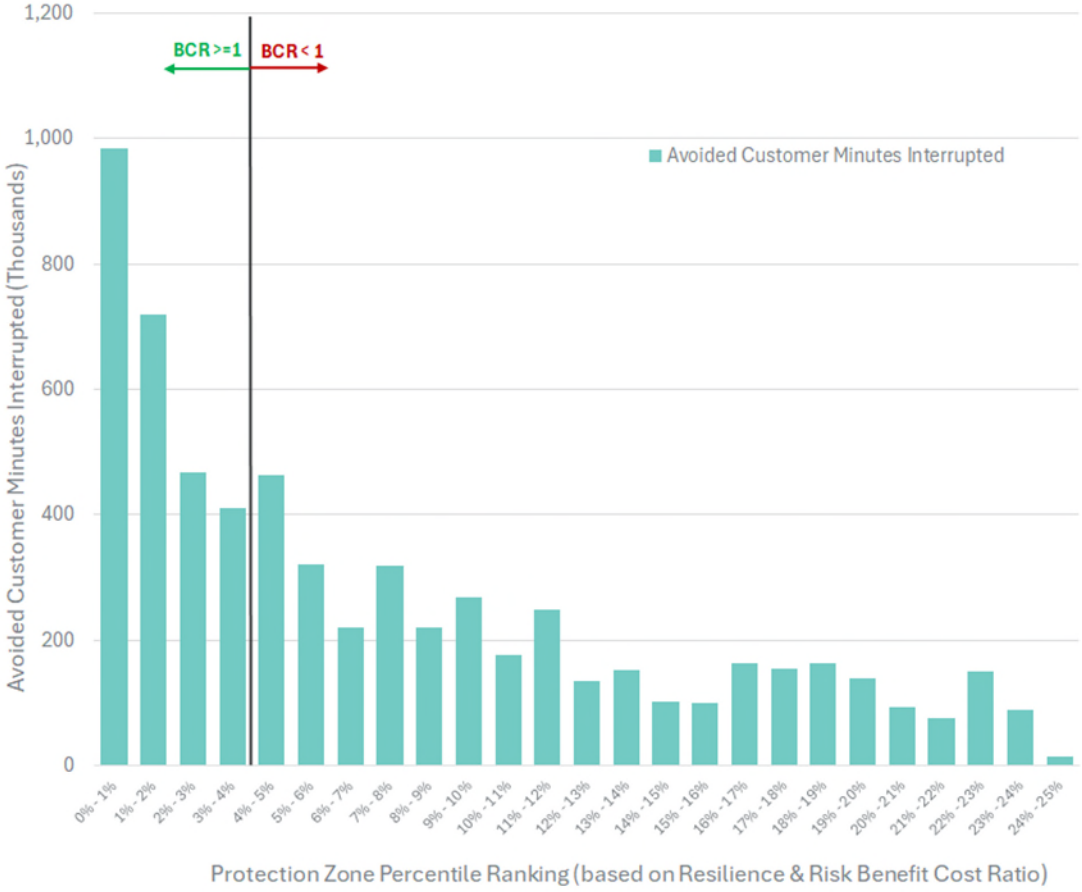
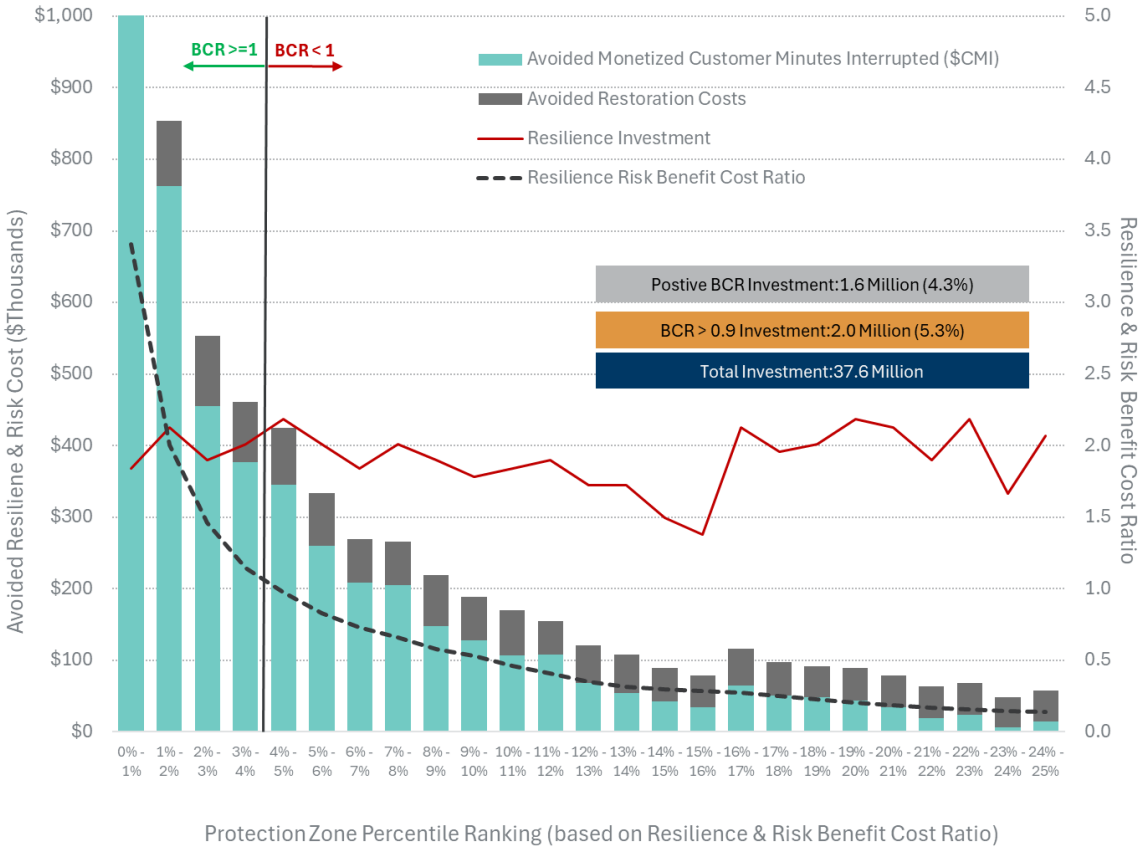


Figure 6-11 takes the CMI benefits from Figure 6-10 and applies the modified DOE ICE Calculator (see Section 5.5) to monetize the outages, adds the avoided restoration costs for each circuit, and includes the expected resiliency investment for each circuit to show the Resiliency & Risk BCR. The circuits are ranked from highest to lowest in terms of BCR. As the figure shows, if this program were applied to the entire SPS distribution system the total investment would be $38 million. Most of the quantified benefits are from avoided customer outages, and approximately $2 million, or 4.3% of the total potential investment level, has quantified benefits in excess of cost. These investments with a BCR >= 1 have total quantified benefits of $3.49 million for an aggregate BCR of 1.79.

Figure 6-11: Lateral Reclosing Deployment Program Resiliency & Risk BCR Summary



6.2.5 Reasonable Alternatives Review

16 TAC § 25.62(c)(2)(A)(v)
The resiliency plan must explain the selection of each measure over any reasonable and readily-identifiable alternatives. The resiliency plan must contain sufficient analysis and evidence, such as cost or performance comparisons, to support the selection of each measure. In selecting between measures, whether a measure would support the plan's systematic approach may be considered

SPS and 1898 & Co. considered various alternatives around the level of segmentation (customer pod size) for each circuit. As part of the program development and scoping process, many of these possible alternatives were evaluated and the best configuration was selected for each feeder; specifically, the evaluation considered different levels of segmentation and selected the number of segments required to provide the most benefit for customers that is technically feasible. Section 4.2.2.1 describes this approach. Therefore, the consideration of distribution protection

modernization alternatives has been considered and evaluated as part of the scope definition process for each feeder.

6.3 Communication Modernization Measure

The Communication Modernization Measure includes investments to deploy a private communication network to enable device communication across the SPS system. The measure includes the following methods:

(B) modernizing electric substation and transmission communication facilities; and

Through this SRP, SPS plans to significantly advance their goal of modernizing the grid and integrating operational technology and information technology to decrease customer outages and manage other system risks.

To achieve this goal, SPS will need to make significant investments in grid devices (e.g., reclosers) and communications systems to enable communication between devices. SPS has already invested in operational technology systems to manage the system communications. For the deployment of devices, this SRP includes the Distribution System Protection Modernization Measure, as described in Section 6.2. Part of the scope of those projects includes the replacement and costs associated with deploying private circuit communication equipment to enable secure, reliable connectivity across the equipment scoped in Section 6.2. The Communication Modernization Measure includes the investment to modernize the communications network across the SPS service territory to provide the network availability, bandwidth, and latency for remote device operations. These investments in communication are foundational to enable the full effectiveness of the communications-enabled protection devices. The following subsection includes:

- A summary description of the measure;
- A review of the events the measure is expected to mitigate; and
- The effectiveness and the benefits of the measure.

6.3.1 Measure Description

16 TAC § 25.62(c)(2)
The resiliency plan must be organized by measure, including a description of any activities, actions, standards, services, procedures, practices, structures, or equipment associated with each measure.

In designing the Communication Modernization Measure SPS considered: (1) the types and level of investment needed to support the other resiliency measures, mainly the Mainline Automated Reclosing Deployment Program; SPS's long-term goal for operational technology; and (3) existing capabilities gaps with communications systems employed by SPS. This measure includes investments in an encrypted, reliably available, and private LTE (pLTE) network, including pLTE towers, fiber optic cable and RTU installations. Specifically, the measure includes the following investment activities, as provided by SPS:

- 49 pLTE towers
- 83 line miles of OPGW line installation across 6 circuits
- 6 substation fiber terminations
- 4 RTU installations

Each of the program specifics are further described in SPS's SRP filing.

6.3.2 Risk of Events Mitigated by Measure

16 TAC § 25.62(c)(2)(B)(iv)
A resiliency plan must provide sufficient evidence to support the presence of and risk posed by each identified resiliency event.

As discussed above, this measure will provide a reliable, secure communications network across SPS's service area to support the full capabilities of the Distribution System Protection Modernization Measure. As such, this measure indirectly mitigates the same weather events that are mitigated by that measure. See 6.2.2 for a review of those weather events.

6.3.3 Evidence of Effectiveness and Benefits

16 TAC § 25.62(c)(2)(A)

(ii) The resiliency plan must include evidence of the effectiveness of the measure in preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the identified resiliency event. The commission will give greater weight to evidence that is quantitative, performance-based, or provided by an independent entity with relevant expertise.

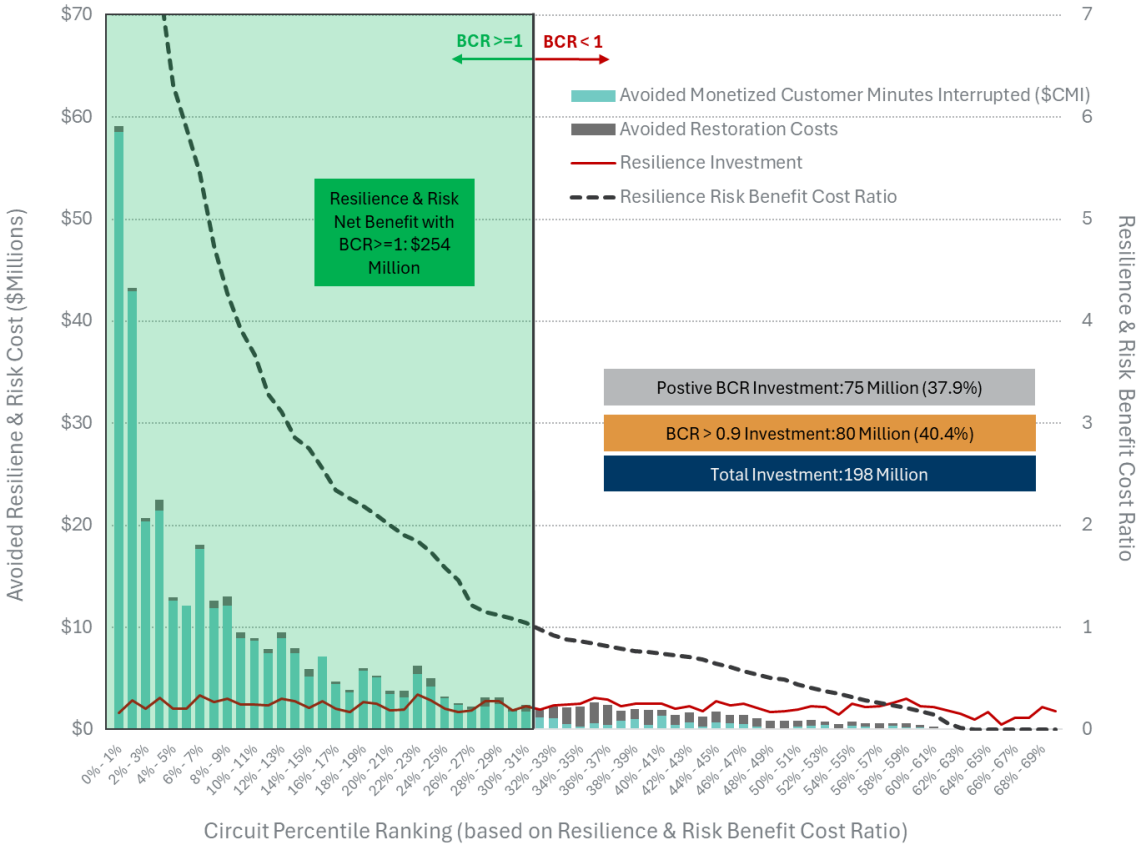
(iii) A resiliency plan must explain the expected benefits of the resiliency measures including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers. and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations.

The Communication Modernization Measure is key to unlocking the Distribution System Protection Modernization Measure's full benefits, which derive from the ability to sectionalize the system and automate customer load transfer to adjacent circuits during outages. Specifically, the Mainline Automated Recloser Deployment Program within the Distribution System Protection Modernization Measure will be more secure, have increased availability, provide more precise system control, and become more scalable across SPS's service area when combined with the Communication Modernization Measure. Combining the measures will eliminate constraints on bandwidth and network availability associated with reliance on public communications networks. Otherwise, the Mainline Automated Recloser Deployment Program will be less effective at minimizing outages for customers and managing other system risks. Because of this, it is appropriate to include the costs of the Communication Modernization Measure in the BCR calculation for the Distribution System Protection Modernization Measure; specifically, with the Mainline Automated Recloser Deployment Program. SPS provided 1898 & Co. with the expected scope and costs for the investment activities described above. SPS estimates the capital expense of this measure at $104.6 million.

To evaluate the BCA for this measure, 1898 & Co. estimated the excess quantified benefits from the Mainline Automated Recloser Deployment Program. As noted above, the Communication Modernization measure supports the device communications in the Mainline Automated Recloser Deployment Program. This is demonstrated in Figure 6-12. This figure shows the same circuit- level ranking results as Figure 6-9, showing

including the excess avoided $CMI, avoided restoration costs, resilience investment, and net resilience and risk benefits for those substations where the BCR was greater than or equal to 1.0. As the figure shows, the net excess benefits are approximately $254 million.

Figure 6-12: Mainline Automated Reclosing Deployment Program Resiliency & Risk Excess Benefits



1898 & Co. compared these quantified benefits to the estimated lifecycle cost of Communication Modernization. 1898 & Co. utilized the investment levels from SPS and estimated the 25-year lifecycle present value of cost of approximately $104.6 million.

The direct circuit investment in the Mainline Automated Reclosing Deployment produces benefits of approximately $330 million with an investment of approximately $76 million, with a BCR of 4.3 and excess benefits of approximately $254 million. The additional investment of $105 million is foundational to realize these excess benefits. After incorporating the cost of the Communication Modernization investments, the

BCR of the combined programs is 1.8 ($330 / ($76 + $105)). This shows that the investments in Communication Modernization measure are expected to produce benefits in excess of costs for customers.

7.0 Investment Project Selection Benefit Cost Summary

1898 & Co. utilized a resilience and risk-based planning approach to identify, prioritize, and perform a benefit-cost analysis to support the development of the SPS SRP. The resilience and risk-based planning approach utilizes a suite of planning models and the Integrated Resilience & Risk Investment Model developed by 1898 & Co. For the purposes of this evaluation, resilience and risk benefits for investment activities are estimated from a customer-centric perspective that aligns with the requirements of the Resiliency Rule.[39] The customer benefits are shown in terms of the:

1. Decrease in utility restoration costs; and
2. Decrease in the number of customers impacted and the duration of the overall outage, calculated as CMI and $CMI.

From these benefit streams, the model calculates the resilience and risk BCR for each investment activity, program, and substation.

$$Resilience\ \&\ Risk\ BCR = \frac{Lifecycle\ PV\ Avoided\ Restoration\ Costs + Lifecyle\ PV\ Avoided\ \$CMI}{Lifecyle\ Resilience\ Investment}$$

As noted above, this single value – the Resilience & Risk BCR for each investment activity, aggregated to each circuit - is a sophisticated, multi-factored analysis. **This makes the BCR value a robust and reliable measure to understand the justification of resilience investment activities**. This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for customers. **Additionally, given the alignment of the factors to the Resiliency Rule, the BCR is a metric that aligns the investment activity to the Resiliency Rule.** This value serves as a guidepost for prioritizing resilience investment on a system of SPS's size.

[39] *See* 16 TAC § 25.62(c)(2)(A)(iii).

While the Resilience & Risk BCR incorporates many factors, it does not capture all benefit streams. 1898 & Co. recognizes that more subjective or difficult-to-quantify risk factors have not been incorporated into the evaluation. Two key subjective factors are safety and areas of lower performance. It is important to note that the Resiliency Rule specifically prioritizes "areas of lower performance."[40] The Resilience & Risk BCR should be utilized as a key tool in prioritizing and selecting investments, in concert with other criteria that incorporate benefits streams not included within the quantified evaluation. Incorporating the quantitative and qualitative assessments together is powerful in investment decision making. This section outlines the systematic approach to identify investments to include in the SRP and the resulting benefit-cost results.

7.1 Benefit-Cost Analysis Summary

Table 7-1 provides an overview of the benefit cost analysis from Section 6.0 above.

Table 7-1: Benefit-Cost Evaluation Summary

Measure / Program	Avg. BCR for Investment with BCR≥1	Investment with BCR ≥1	Investment with BCR ≥0.9	% Improvement in CMI for BCR ≥1
Distribution Overhead Hardening Measure (Distribution Circuit Protection Hardening Program)	2.1	$1.76B	$1.93B	54%
Distribution System Protection Modernization: Mainline Automated Reclosing Deployment Program[41]	4.3	$76.1M	$79.7M	38%
Distribution System Protection Modernization: Lateral Reclosing Deployment Program	1.9	$1.7M	$2.0M	21%
Communication Modernization[41]	N/A	$104.6M	$104.6M	N/A
Total	**2.1**	**$1.94B**	**$2.12B**	**N/A**

The table shows nearly $2 billion of potential resiliency investment on the SPS system with benefits in excess of costs for customers. These potential investments have a

[40] 16 TAC § 25.62(d)(4)(A) and (d)(4)(C)(i)(III).
[41] As described in Section 6.3.3 the Communication Modernization investment enables the full effectiveness of the mainline automated reclosing deployment program. Section 6.2.4.1 shows a BCR of 4.3 for the mainline automation program. As shown in Section 6.3.3, the combined program BCR is 1.8.

BCR of 2.1, demonstrating a significant opportunity to reduce customer outages, by over 50% for circuits where hardening investment is made and by almost 40% for mainline automation. Most of this potential investment, over 90%, is in the Distribution Overhead Hardening Measure.

7.2 Systematic Approach to Identify SRP Investment Activities

16 TAC § 25.62(c)(2)(E)
A resiliency plan must be implemented using a systematic approach over a period of at least three years. The resiliency plan must explain this systematic approach and provide implementation details for each of the plan's measures, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments. The resiliency plan should identify relevant cost drivers (e.g., line miles, frequency of inspections, frequency of trim cycles, etc.) that would affect the estimates.

This section summarizes, based on the previous sections outlined above, the systematic approach employed by SPS and 1898 & Co. to organize specific investment activities and measures into the portfolio of executable investments that are included in SPS's SRP. This section only covers the measures evaluated by 1898 & Co. In developing the implementation approach to select specific investment activities, SPS considered the following:

- Organizational objectives, mainly deploying system protection modernization broadly across Wildfire Tiers 2 and 3 zones;
- Execution realities in terms of equipment availability and other execution constraints; and
- The benefit cost ratios outlined above.

Safety risks and consequences are challenging to quantify and incorporate into the investment evaluation and justification framework based on the BCR. Accordingly, 1898 & Co.'s evaluation does not directly include safety-related benefit streams. Rather, when evaluating benefit-cost results, 1898 & Co. balanced the quantified benefits results and safety risk mitigation. For investments with BCR less than 1.0 but greater than 0.9, the general safety risks, and other qualitative considerations would

provide sufficient direct benefits such that the total benefits would be in excess of cost. Investment activities with a BCR less than 0.9 should be evaluated on a case-by-case basis, as direct quantifiable benefits are not the only consideration influencing investment activity justification. Benefits like improving service quality to areas of lower performance or mitigating specific safety risks, such as wildfire risk, may justify pursuing investments with a lower BCR value and should be considered in the investment decision. The results presented throughout this report include the investment level with a BCR greater than a 0.9.

SPS intends to execute both the Distribution Overhead Hardening and Distribution System Protection Modernization measures on a circuit-by-circuit basis. SPS further intends to execute each of these measures independently from one another. This is mainly due to differences in equipment availability, engineering and construction timelines, and business objective priorities; specifically, modernizing protection schemes across Wildfire 2 and 3 zones.

SPS provided the following structure that 1898 & Co. utilized to identify specific investments to develop and include in the SRP:

- Distribution System Protection Modernization Measure
  - Include any circuit investment where the BCR is greater than or equal to 0.9. Execution constraints were not exceeded at this investment level; and
  - For any circuit selected based on the BCR threshold that is located in a Wildfire Tier 2 or 3 zone, also include the wildfire-specific investment activities.
- Distribution Overhead Hardening Measure
  - Prioritize Distribution Overhead Hardening investment activities at the protection zone level by BCR (assuming mainline automation is implemented from Figure 6-6) and include all protection zones up to a certain investment threshold based on budgetary and execution constraints;
  - Organize the selected protection zones to the circuit level; and
  - For any protection zone selected that is in Wildfire Tier 2 or 3 zone, also include the wildfire-specific investment activities.

7.3 SRP Investment and BCA Summary

Table 7-2 provides a summary of the investment level for each of the measures evaluated by 1898 & Co. by wildfire tier and investment activity type. The table also includes the wildfire-specific investment activities that were not evaluated by 1898 & Co. These values are based on the structure outlined above. For the measures evaluated by 1898 & Co. the SRP's planned investment level is $425.1 million (in 2024).

Table 7-2: SRP Investment Summary (2024 Millions)

Wildfire Tier / Investment Activity Type	Distribution Overhead Hardening Measure	Distribution System Protection Modernization Measure		Communication Modernization	Total
	Distribution Circuit Protection Hardening	Mainline Automated Reclosing Deployment Program	Lateral Reclosing Deployment Program		
Wildfire Tier 3	**$155.8**	**$37.8**	**$0**		**$193.6**
BCR Analysis Activities	$154.1	$35.0	$0		$189.1
Wildfire Specific Activities	$1.7	$2.7	$0		$4.4
Wildfire Tier 2	**$61.2**	**$22.3**	**$0**		**$83.5**
BCR Analysis Activities	$60.6	$21.1	$0		$81.7
Wildfire Specific Activities	$0.6	$1.3	$0		$1.9
Wildfire Teir 1	**$17.8**	**$23.6**	**$2.0**		**$43.4**
BCR Analysis Activities	$17.8	$23.6	$2.0		$43.4
Wildfire Specific Activities	$0	$0	$0		$0
Total	**$234.8**	**$83.7**	**$2.0**	**$104.6**	**$425.1**
BCR Analysis Activities	$232.5	$79.7	$2.0	$104.6	$418.8
Wildfire Specific Activities	$2.4	$4.0	$0		$6.4

The Distribution Overhead Hardening measure accounts for 55.2% of the total investment, followed by Communication Modernization at 24.6%. The Mainline Automated Reclosing Deployment Program is approximately 19.7% of the total, with the Lateral Reclosing Deployment making up the smallest portion at 0.5%. From a wildfire tier perspective, Tier 3 includes approximately 60% of the total investment for the Distribution Overhead Hardening and Distribution System Protection

Modernization measures. Wildfire Tier 2 accounts for approximately 26% of the total, and Tier 1 accounts for 14%.

Table 7-3 shows the BCA results for the SRP. The investment dollars in the table do not include any of the wildfire-specific activities from Table 7-2. For the investments evaluated by 1898 & Co., the overall BCR is approximately 3.4.

Table 7-3: SRP Benefit-Cost Evaluation Summary

Measure / Program	Avg. BCR	SRP Investment (2024$)	Benefits (2024$)	% Improvement in CMI
Distribution Overhead Hardening Measure (Distribution Circuit Protection Hardening Program)	4.7	$232.5M	$1,094.5M	58%
Distribution System Protection Modernization: Mainline Automated Reclosing Deployment Program[42]	4.2	$79.7M	$333.0M	37%
Distribution System Protection Modernization: Lateral Reclosing Deployment Program	1.8	$2.0M	$3.5M	21%
Communication Modernization[42]	N/A	$104.6M	N/A	N/A
Total	**3.4**	**$418.8M**	**$1,431M**	**N/A**

These investments also show a significant improvement in customer outages, approximately 58% for those circuits where hardening investment is made and approximately 37% for mainline automation. Comparing Table 7-1, which includes the BCA for the whole system, and Table 7-3 which shows the BCA for the SRP, the SRP includes all investments with a 0.9 BCR or greater for the Distribtion System Protection Modernization measure. The comparison also shows that the Distribution Overhead Hardening measure has more investment with a positive BCR than is part of the SRP.

7.4 Conclusions

[42] As described in Section 6.3.3 the Communication Modernization investment enables the full effectiveness of the mainline automated reclosing deployment program. Section 6.2.4.1 shows a BCR of 4.3 for the mainline automation program. As shown in Section 6.3.3, the combined program BCR is 1.8.

This section summarizes the conclusions of the BCA for the resiliency investment activities that make up SPS's SRP, as evaluated within 1898 & Co.'s Integrated Resilience & Risk Investment Model:

- The resilience and risk BCR value is a robust and reliable measure to help understand the justification for resilience investment activities. **This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for customers.** Additionally, given the alignment of the BCR factors to the Resiliency Rule, the BCR aligns the investment activity to the Resiliency Rule.
- **The benefit cost evaluation shows significant opportunity to improve distribution system resiliency for SPS customers** with nearly $2 billion of investment with a BCR greater than or equal to 1.0 for the quantified measures shown in Table 7-1. Each of these investments provides quantified customer benefits in excess of cost.
- **The SRP measures evaluated by 1898 & Co. are expected to provide benefits in excess of costs for SPS customers.** The investment level of $418.8 million is expected to provide $1,431 million of benefits with an average BCR of 3.4. All of the investment activities included in the SRP have a BCR ≥ 0.9.
- **The quantified benefit-cost analysis shows SPS's proposed investment level under the SRP is less than the potential investment with a BCR greater than or equal to 1.0.** SPS's proposed investment under the SRP is approximately 22% ($418.8 / $1,940) of the total potential investment in investment activities with a BCR ≥ 1.0, and 20% ($418.8 / $2,120) of the total potential investment in projects with a BCR ≥ 0.9.
- **Communication Modernization is a key investment to unlock the full potential of other investments in the SRP, particularly investments in the Distribution System Protection Modernization measure.** Without Communication Modernization, several of those investments will be less secure and will not offer the full range of benefits they are capable of providing. The quantified excess benefits from other measures that the Communication

Modernization measure enables are in excess of this measure's life-cycle costs. The combined BCR of the Distribution System Protection Modernization measure for investments with a BCR ≥ 1.0 and the Communication Modernization measures is 1.8.

- **The plan will benefit all SPS customers**. Avoided outage restoration costs are shared by all distribution customers. Additionally, distribution customers will experience fewer storm outages from both direct and indirect causes. Direct benefits are realized by those customers whose infrastructure is located directly downstream of the resiliency investment. Indirect benefits are realized by all distribution customers, since storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.
- **The resilience investment benefits are conservative**. First, the benefits outlined above are only direct benefits to specific resiliency measures and do not factor in the indirect benefits from lower overall storm restoration durations. Second, the DOE ICE Calculator is likely conservative for residential customers, as the underlying data pre-dates the significant advancements in societal use of electronic devices and technologies or trends toward work-from-home arrangements (see Section 5.5 for additional information), and the DOE ICE Calculator has not been updated to account for this societal shift. Third, the quantified benefit-cost assessment has carefully included the full cost of implementing resiliency investments; however, the full level of benefits has not been captured. Specifically, the evaluation has not incorporated qualitative benefits associated with enhanced safety or service improvement in areas of lower performance.
- **The SRP is an integrated portfolio** of measures and investments designed to collectively prevent, withstand, mitigate, and more promptly recover from the risks posed to SPS's system from a wide range of resiliency events. Excluding any programs within the proposed measures may impact the expected benefit of the other remaining programs or measures (*see* Section 2.4).



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Summary Table

Measure	Program	Resiliency Risk Event	Activities	Estimated Structure and Equipment Count/Miles	Estimated SRP Spend ($)
Distribution Hardening Overhead	Distribution Circuit Hardening Rebuild	Wind, Flooding, Tornado, Winter, Heat, and Cold	1) Pole Replacements 2) Conductor and Open-Wire Secondary Replacements 3) Line Transformer Replacements 4) Pole wraps 5) Pole Trussing 6) Wildfire Transmission Ignition Mitigation Fuse Replacements 7) Wildfire Arrestor Replacements	1.1) Replacement of over 10,000 poles 1.2) Installation of over 5,000 new poles 2.1) Replacement of approx. 800 miles of primary 2.2) Replacement of approx. 10 miles of secondary 3.1) Replacement of approx. 500 transformers 4.1) Wrapping of over 14,000 poles 5.1) Installation of over 1,500 trusses 6.1) Replacement of approx. 450 fuses 7.1) Replacement of over 150 arrestors	Capital: 253.0M O&M: -- Total: 253.0M
Distribution System Protection Modernization	Mainline Automated Reclosing Deployment	Wind, Flooding, Tornado, Winter, Heat, and Cold	1) Sectionalizing Recloser Installation 2) Tie Recloser Installation 3) Existing Recloser Communication Installation 4) Substation Relay Panel Replacements 5) Substation Breaker Replacements 6) Fault Indicator Installation 7) Enhanced Powerline Safety Setting Feeder Upgrades 8) Wildfire Fuse Replacements	1.1) Installation of approx. 400 new reclosers 2.1) Installation of over 200 tie reclosers 3.1) Replacement of approx. 50 reclosers 3.2) Communications upgrades to approx. 30 reclosers 4.1) Replacement of approx. 60 relay panels 5.1) Replacement of approx. 20 breakers 6.1) Installation of approx. 950 fault indicators 7.1) Upgrades to approx. 150 feeders 8.1) Replacement of over 2,500 wildfire fuses	Capital: 90.1M O&M: -- Total: 90.1M
	Lateral Reclosing Deployment	Wind, Flooding, Tornado, Winter, Heat, and Cold	1) Installation of Lateral Reclosers	1.1) Installations on approx. 60 lateral taps 1.2) Installation of approx. 170 devices	Capital: 2.1M O&M: -- Total: 2.1M

Measure	Program	Resiliency Risk Event	Activities	Estimated Structure and Equipment Count/Miles	Estimated SRP Spend ($)
Communication Modernization	Communication Modernization	Wind, Flooding, Tornado, Winter, Heat, Cold, Cybersecurity	1) Private LTE Network Buildout Private Fiber Optic and RTU Installation	1.1) Construction of 49 pLTE towers 1.2) Construction of 6 POPGW line segments 1.3) Construction of 6 OPGW sub terminations 1.4) Installation of 4 RTUs	Capital: 112.6M O&M: -- Total: 112.6M
Operational Flexibility	Mobile Substation Equipment Procurement	Wind, Winter, Heat, Cold	1) Equipment Procurement	1.1) Procurement of 6 mobile substations 1.2) Procurement of 1 mobile regulator trailer 1.3) Procurement of 1 circuit switcher trailer	Capital: 30.8M O&M: 0.006M* Total: 30.8M *Calculated based on a $36/month charge
	Installation of Transmission Switches	Wind, Winter, Heat, Cold	1) Installation of Transmission Switches	1.1) Installation of 14 loadbreak switches 1.2) Installation of 3 non-loadbreak switches	Capital: 12.8M O&M: -- Total: 12.8M
Wildfire Mitigation	Situational Awareness	Wildfire	1) Enhanced Meteorology Capabilities 2) Weather and Fire Science Modeling 3) Artificial Intelligence Cameras 4) Wildfire Tier Maps	1) Addition of over 100 weather stations 2) Addition of FireSight RAIL and RAVE modeling software 3) Installation of approx. 70 Pano cameras (Tiers 2 and 3) 4) Updated on a 3-year basis	Capital: 17.9M O&M: 1.3M Total: 19.1M
	Operational Mitigation	Wildfire	1) Defensible Space Around Poles (DSAP) 2) Wood Substation Conversion 3)Transmission Wildfire Annual Visual Inspection	1.1) Address over 12,000 distribution poles (Tiers 2 and 3) 1.2) Address approx. 200 transmission poles (Tiers 2 and 3) 2.1) Convert 4 substations 3.1) Inspect over 3,000 miles annually (Tiers 2 and 3)	Capital: 2.9M O&M: 14.9M Total: 17.8M

Pano AI's Impact on Wildfire Mitigation

December 2024

Overview

Pano provides Pano Rapid Detect, which is an integrated solution designed to provide actionable intelligence about new fire ignitions. SPS plans to leverage Pano Rapid Detect, along with other situational awareness measures, in West Texas to mitigate wildfire risks.

Situational Awareness

Relying solely on the public to report wildfires may present challenges in both timeliness and accuracy. Delays may occur because the public may not immediately recognize the signs of a wildfire or may be hesitant to report incidents they're unsure of. This potential lag can allow fires to grow in size and intensity before response teams are alerted. Furthermore, reports may include vague or incorrect details about the fire's location, making it more difficult for response teams to act swiftly and deploy resources effectively. Lastly, false alerts may divert resources from actual emergencies and lead to delays in responding to real wildfires, allowing them to grow in size and intensity.

Pano aims to improve situational awareness beyond relying solely on public reports. The Pano Rapid Detect product (described in greater detail below) aims to provide actionable intelligence about wildfires that can be used by customers (e.g., their emergency management teams) and first responders to improve response and mitigate risk.

Product Overview

Pano Rapid Detect leverages data feeds from Pano-deployed hardware (Pano Stations), as well as other data feeds, a cloud data integration platform (Pano Connect), proprietary AI algorithms for fire detection both day and night (Pano AI), a human review capability (Pano Intelligence Center), and a front-end user interface (Pano 360).

- Pano Stations are designed to capture 360-degree panoramic imagery, which is a key data feed in the Pano Rapid Detect solution. Pano manufactures, deploys, and maintains the global network of Pano Stations.
- Pano Rapid Detect
    - Pano Connect is Pano's cloud-based platform for data ingestion and storage (e.g., from Pano Stations and 3rd party data, such as satellite data and incident information derived from 911 calls where available)
    - Pano AI is Pano's proprietary artificial intelligence (AI) algorithms to support fire incident detection.
    - Pano Intelligence Center provides 24/7 human review to support fire incident detection and validation.

- Pano 360 allows users to view and interact with the Pano Station feeds, view incident details, and set notification preferences for notifications of new fire incidents.

The information provided by Pano Rapid Detect, used in conjunction with other available information, may be leveraged by customers and first responders to support improved detection and response to wildfires. Notifications may help customers and first responders address wildfires in their earlier stages, before they become more difficult and costly to manage. Visual information and incident details may help customers and first responders deploy resources more strategically and effectively, thereby mitigating risk.

Pano Rapid Detect has detected and alerted customers and first responders to hundreds of fires across multiple states, including Utah, Oregon, Washington, Idaho, Montana, Colorado, California, Wyoming, Texas, British Columbia, and five states in Australia.

Case Study: Bear Creek Fire*

On June 16, 2024, at approximately 9:30 AM, the U.S. Forest Service and Pano Rapid Detect simultaneously detected smoke caused by a lightning strike in the Bennett Mountain area above Strontia Springs Reservoir in Douglas County in Colorado. Pano Rapid Detect provided triangulated coordinates, a video of the smoke, and notification of the fire incident.

Given the conditions of the day, a Red Flag Warning with high temperatures and low humidity, Emergency Services determined this was a high-risk fire with the potential to spread quickly. By 9:54 AM, the department launched a helitack response with two 5TA helicopters when the fire was at 0.25 acres, burning on the remote north side of Bennett Mountain, near Bear Creek. An Emergency Services crew of nearly 40 hiked 2.5 hours from Waterton Canyon to reach the site.

The helitack lasted 5.5 hours, dropping 56 tanks of water totaling 17,765 gallons. By 7:00 PM, the fire was fully contained at three acres. This rapid initial attack prevented the fire from potentially progressing to a large-scale, hard-to-contain fire.

**Provided for illustrative purposes only. Past performance does not guarantee future results. Variability in fire behavior, environmental conditions, response, and other factors can influence outcomes.*

ATTACHMENT B – LETTERS OF NOTICE

Brad Baldridge
Senior Director, Customer & Community Relations
Southwestern Public Service Company
790 South Buchannan Street
Amarillo, Texas 79101
Brad.baldridge@xcelenergy.com
Phone: 806-378-2919

December 31, 2024

City of _____
[Address]
[City], TX [Zip]

Re: Notice of Southwestern Public Service Company's Application for Approval of a System Resiliency Plan in Public Utility Commission of Texas Docket No. 57463

To the Honorable Mayor of [MUNICIPALITY]:

Our customers expect reliable electricity. At Xcel Energy, we know it's our job to deliver it safely, 24 hours a day, 365 days a year. That is why we're committed to modernizing and hardening our grid, while ensuring continued safe operation.

Enacted by state legislation and implemented under Public Utility Commission of Texas rule (Commission), system resiliency plans pave the way for accelerated system upgrades to enhance the resilience of energy providers' distribution and transmission systems to better respond to extreme weather, wildfires and other reliability threats.

On December 31, 2024, Southwestern Public Service Company (SPS) filed with the Commission an application for approval of a system resiliency plan pursuant to Public Utility Regulatory Act (PURA) § 38.078 and 16 Texas Administrative Code § 25.62 (Application). The purpose of this letter is to notify you of the Application, which can be accessed on the Commission's interchange here: https://interchange.puc.texas.gov/ (search control number 57463).This case has been assigned Docket No. 57463 and falls under the exclusive jurisdiction of the Commission. Any person wishing to participate in this proceeding by becoming an intervenor must file a written request with the Commission. Intervention requests may be submitted electronically using the Commission's interchange filer, available at https://interchange.puc.texas.gov/filer, or by mail to: Public Utility Commission of Texas Central Records 1701 North Congress Avenue, P.O. Box 13326, Austin, TX 78711-3326. The deadline for intervention in this proceeding is **January 30, 2025**.

If you have any questions concerning this proceeding, please do not hesitate to contact me.

Sincerely,

Brad Baldridge

Brad Baldridge
Senior Director, Customer & Community Relations
Southwestern Public Service Company
790 South Buchannan Street
Amarillo, Texas 79101
Brad.baldridge@xcelenergy.com
Phone: 806-378-2919

December 31, 2024

Mr. Benjamin Barkley
Chief Executive & Public Counsel Office of Public Utility Counsel
1701 North Congress Avenue, Suite 9-180
P.O. Box 12397
Austin, Texas 78711

Re: Notice of Southwestern Public Service Company's Application for Approval of a System Resiliency Plan in Public Utility Commission of Texas Docket No. 57463

Dear Mr. Barkley:

Our customers expect reliable electricity. At Xcel Energy, we know it's our job to deliver it safely, 24 hours a day, 365 days a year. That is why we're committed to modernizing and hardening our grid, while ensuring continued safe operation.

Enacted by state legislation and implemented under Public Utility Commission of Texas rule (Commission), system resiliency plans pave the way for accelerated system upgrades to enhance the resilience of energy providers' distribution and transmission systems to better respond to extreme weather, wildfires and other reliability threats.

On December 31, 2024, Southwestern Public Service Company (SPS) filed with the Commission an application for approval of a system resiliency plan pursuant to Public Utility Regulatory Act (PURA) § 38.078 and 16 Texas Administrative Code § 25.62 (Application). The purpose of this letter is to notify you of the Application, which can be accessed on the Commission's interchange here: https://interchange.puc.texas.gov/ (search control number 57463). This case has been assigned Docket No. 57463 and falls under the exclusive jurisdiction of the Commission. Any person wishing to participate in this proceeding by becoming an intervenor must file a written request with the Commission. Intervention requests may be submitted electronically using the Commission's interchange filer, available at https://interchange.puc.texas.gov/filer, or by mail to: Public Utility Commission of Texas Central Records 1701 North Congress Avenue, P.O. Box 13326, Austin, TX 78711-3326. The deadline for intervention in this proceeding is January 30, 2025.

If you have any questions concerning this proceeding, please do not hesitate to contact me.

Sincerely,

Brad Baldridge

Brad Baldridge
Senior Director, Customer & Community Relations
Southwestern Public Service Company
790 South Buchannan Street
Amarillo, Texas 79101
Brad.baldridge@xcelenergy.com
Phone: 806-378-2919

December 31, 2024

Mike Ross
Sr. VP, External Affairs and Stakeholder Relations
Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223

Re: Notice of Southwestern Public Service Company's Application for Approval of a System Resiliency Plan in Public Utility Commission of Texas Docket No. 57463

Dear Mr. Ross:

Our customers expect reliable electricity. At Xcel Energy, we know it's our job to deliver it safely, 24 hours a day, 365 days a year. That is why we're committed to modernizing and hardening our grid, while ensuring continued safe operation.

Enacted by state legislation and implemented under Public Utility Commission of Texas rule (Commission), system resiliency plans pave the way for accelerated system upgrades to enhance the resilience of energy providers' distribution and transmission systems to better respond to extreme weather, wildfires and other reliability threats.

On December 31, 2024, Southwestern Public Service Company (SPS) filed with the Commission an application for approval of a system resiliency plan pursuant to Public Utility Regulatory Act (PURA) § 38.078 and 16 Texas Administrative Code § 25.62 (Application). The purpose of this letter is to notify you of the Application, which can be accessed on the Commission's interchange here: https://interchange.puc.texas.gov/ (search control number 57463). This case has been assigned Docket No. 57463 and falls under the exclusive jurisdiction of the Commission. Any person wishing to participate in this proceeding by becoming an intervenor must file a written request with the Commission. Intervention requests may be submitted electronically using the Commission's interchange filer, available at https://interchange.puc.texas.gov/filer, or by mail to: Public Utility Commission of Texas Central Records 1701 North Congress Avenue, P.O. Box 13326, Austin, TX 78711-3326. The deadline for intervention in this proceeding is January 30, 2025.

If you have any questions concerning this proceeding, please do not hesitate to contact me.

Sincerely,



Brad Baldridge

Brad Baldridge
Senior Director, Customer & Community Relations
Southwestern Public Service Company
790 South Buchannan Street
Amarillo, Texas 79101
Brad.baldridge@xcelenergy.com
Phone: 806-378-2919

December 31, 2024

All Authorized Representatives for Parties in Docket No. 54634

Re: Notice of Southwestern Public Service Company's Application for Approval of a System Resiliency Plan in Public Utility Commission of Texas Docket No. 57463

Notice to All Authorized Representatives for Parties in Docket No. 54634:

Our customers expect reliable electricity. At Xcel Energy, we know it's our job to deliver it safely, 24 hours a day, 365 days a year. That is why we're committed to modernizing and hardening our grid, while ensuring continued safe operation.

Enacted by state legislation and implemented under Public Utility Commission of Texas rule (Commission), system resiliency plans pave the way for accelerated system upgrades to enhance the resilience of energy providers' distribution and transmission systems to better respond to extreme weather, wildfires and other reliability threats.

On December 31, 2024, Southwestern Public Service Company (SPS) filed with the Commission an application for approval of a system resiliency plan pursuant to Public Utility Regulatory Act (PURA) § 38.078 and 16 Texas Administrative Code § 25.62 (Application). The purpose of this letter is to notify you of the Application, which can be accessed on the Commission's interchange here: https://interchange.puc.texas.gov/ (search control number 57463). This case has been assigned Docket No. 57463 and falls under the exclusive jurisdiction of the Commission. Any person wishing to participate in this proceeding by becoming an intervenor must file a written request with the Commission. Intervention requests may be submitted electronically using the Commission's interchange filer, available at https://interchange.puc.texas.gov/filer, or by mail to: Public Utility Commission of Texas Central Records 1701 North Congress Avenue, P.O. Box 13326, Austin, TX 78711-3326. The deadline for intervention in this proceeding is January 30, 2025.

If you have any questions concerning this proceeding, please do not hesitate to contact me.

Sincerely,

Brad Baldridge

ATTACHMENT C – PROPOSED PROTECTIVE ORDER

DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

PROTECTIVE ORDER

This Protective Order shall govern the use of all information deemed confidential (Protected Materials) or highly confidential (Highly Sensitive Protected Materials), including information whose confidentiality is currently under dispute, by a party providing information to the Public Utility Commission of Texas (Commission) or to any other party to this proceeding.

It is ORDERED that:

1. **Designation of Protected Materials**. Upon producing or filing a document, including, but not limited to, records on a computer disk or other similar electronic storage medium in this proceeding, the producing party may designate that document, or any portion of it, as confidential pursuant to this Protective Order by typing or stamping on its face "PROTECTED PURSUANT TO PROTECTIVE ORDER ISSUED IN DOCKET NO. 57463" (or words to this effect) and consecutively Bates stamping each page. Protected Materials and Highly Sensitive Protected Materials include the documents so designated, as well as the substance of the information contained in the documents and any description, report, summary, or statement about the substance of the information contained in the documents.

2. **Materials Excluded from Protected Materials Designation**. Protected Materials shall not include any information or document contained in the public files of the Commission or any other federal or state agency, court, or local governmental authority subject to the

Public Information Act.[1] Protected Materials also shall not include documents or information which at the time of, or prior to disclosure in, a proceeding is or was public knowledge, or which becomes public knowledge other than through disclosure in violation of this Protective Order.

3. **Reviewing Party**. For the purposes of this Protective Order, a "Reviewing Party" is any party to this docket.

4. **Procedures for Designation of Protected Materials**. On or before the date the Protected Materials or Highly Sensitive Protected Materials are provided to the Commission, the producing party shall file with the Commission and deliver to each party to the proceeding a written statement, which may be in the form of an objection, indicating: (a) any exemptions to the Public Information Act claimed to apply to the alleged Protected Materials; (b) the reasons supporting the producing party's claim that the responsive information is exempt from public disclosure under the Public Information Act and subject to treatment as protected materials; and (c) that counsel for the producing party has reviewed the information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits the Protected Materials designation.

5. **Persons Permitted Access to Protected Materials**. Except as otherwise provided in this Protective Order, a Reviewing Party may access Protected Materials only through its "Reviewing Representatives" who have signed the Protective Order Certification Form (see Attachment A). Reviewing Representatives of a Reviewing Party include its counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by the Reviewing Party and directly engaged in this proceeding. At the request of the PUC Commissioners, copies of Protected Materials may be produced by Commission Staff. The Commissioners and their staff shall be informed of the existence and coverage of this Protective Order and shall observe the restrictions of the Protective Order.

[1] Tex. Gov't Code §§ 552.001–.353.

6. **Highly Sensitive Protected Material Described**. The term "Highly Sensitive Protected Materials" is a subset of Protected Materials and refers to documents or information that a producing party claims is of such a highly sensitive nature that making copies of such documents or information or providing access to such documents to employees of the Reviewing Party (except as specified herein) would expose a producing party to unreasonable risk of harm. Highly Sensitive Protected Materials include but are not limited to: (a) customer-specific information protected by § 32.101(c) of the Public Utility Regulatory Act;[2] (b) contractual information pertaining to contracts that specify that their terms are confidential or that are confidential pursuant to an order entered in litigation to which the producing party is a party; (c) market-sensitive fuel price forecasts, wholesale transactions information and/or market-sensitive marketing plans; and (d) business operations or financial information that is commercially sensitive. Documents or information so classified by a producing party shall bear the designation "HIGHLY SENSITIVE PROTECTED MATERIALS PROVIDED PURSUANT TO PROTECTIVE ORDER ISSUED IN DOCKET NO. 57463" and shall be consecutively Bates stamped. The provisions of this Protective Order pertaining to Protected Materials also apply to Highly Sensitive Protected Materials, except where this Protective Order provides for additional protections for Highly Sensitive Protected Materials. In particular, the procedures herein for challenging the producing party's designation of information as Protected Materials also apply to information that a producing party designates as Highly Sensitive Protected Materials.

7. **Restrictions on Copying and Inspection of Highly Sensitive Protected Material**. Except as expressly provided herein, only one copy may be made of any Highly Sensitive Protected Materials except those additional copies may be made in order to have sufficient copies for introduction of the material into the evidentiary record if the material is to be offered for admission into the record. A record of any copies that are made of Highly Sensitive Protected Material shall be kept and a copy of the record shall be sent to the

[2] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001–66.016.

producing party at the time the copy or copies are made. The record shall include information on the location and the person in possession of each copy. Highly Sensitive Protected Material shall be made available for inspection only at the location or locations provided by the producing party, except as specified by Paragraph 9. Limited notes may be made of Highly Sensitive Protected Materials, and such notes shall themselves be treated as Highly Sensitive Protected Materials unless such notes are limited to a description of the document and a general characterization of its subject matter in a manner that does not state any substantive information contained in the document.

8. **Restricting Persons Who May Have Access to Highly Sensitive Protected Material**. With the exception of Commission Staff, the Office of Public Utility Counsel ("OPUC"), and the Office of the Attorney General ("OAG") when the OAG is representing a party to the proceeding, and except as provided herein, the Reviewing Representatives for the purpose of access to Highly Sensitive Protected Materials may be persons who are: (1) outside counsel for the Reviewing Party; (2) outside consultants for the Reviewing Party working under the direction of Reviewing Party's counsel; or (3) employees of the Reviewing Party or its members working with and under the direction of Reviewing Party's counsel who have been authorized by the producing party or by the presiding officer to review Highly Sensitive Protected Materials. The Reviewing Party shall limit the number of Reviewing Representatives that review each Highly Sensitive Protected document to the minimum number of persons necessary. The Reviewing Party is under a good faith obligation to limit access to each portion of any Highly Sensitive Protected Materials to two Reviewing Representatives (other than outside counsel) whenever possible. Reviewing Representatives for Commission Staff, OPUC, and OAG, for the purpose of access to Highly Sensitive Protected Materials, shall consist of their respective counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by them and directly engaged in these proceedings.

9. **Copies Provided of Highly Sensitive Protected Material**. A producing party shall provide one copy of Highly Sensitive Protected Materials specifically requested by the

Reviewing Party to the person designated by the Reviewing Party who must be a person authorized to review Highly Sensitive Protected Material under Paragraph 8. Representatives of the Reviewing Party who are authorized to view Highly Sensitive Protected Material may review the copy of Highly Sensitive Protected Materials at the office of the Reviewing Party's representative designated to receive the information. Any Highly Sensitive Protected Materials provided to a Reviewing Party may not be copied except as provided in Paragraph 7. The restrictions contained herein do not apply to Commission Staff, OPUC, and the OAG when the OAG is representing a party to the proceeding.

10. **Procedures in Paragraphs 10-14 Apply to Commission Staff, OPUC, and the OAG and Control in the Event of Conflict**. The procedures in Paragraphs 10 through 14 apply to responses to requests for documents or information that the producing party designates as Highly Sensitive Protected Materials and provides to Commission Staff, OPUC, and the OAG in recognition of their purely public functions. To the extent the requirements of Paragraphs 10 through 14 conflicts with any requirements contained in other paragraphs of this Protective Order, the requirements of these Paragraphs shall control.

11. **Copy of Highly Sensitive Protected Material to be Provided to Commission Staff, OPUC and the OAG**. When, in response to a request for information by a Reviewing Party, the producing party makes available for review documents or information claimed to be Highly Sensitive Protected Materials, the producing party shall also deliver one copy of the Highly Sensitive Protected Materials to the Commission Staff, OPUC, and the OAG (if the OAG is representing a party) in Austin, Texas. Provided however, that in the event such Highly Sensitive Protected Materials are voluminous, the materials will be made available for review by Commission Staff, OPUC, and the OAG (if the OAG is representing a party) at the designated office in Austin, Texas. The Commission Staff, OPUC and the OAG (if the OAG is representing a party) may request such copies as are necessary of such voluminous material under the copying procedures specified herein.

12. **Delivery of the Copy of Highly Sensitive Protected Material to Commission Staff and Outside Consultants**. The Commission Staff, OPUC, and the OAG (if the OAG is

representing a party) may deliver the copy of Highly Sensitive Protected Materials received by them to the appropriate members of their staff for review, provided such staff members first sign the certification specified by Paragraph 15. After obtaining the agreement of the producing party, Commission Staff, OPUC, and the OAG (if the OAG is representing a party) may deliver the copy of Highly Sensitive Protected Materials received by it to the agreed, appropriate members of their outside consultants for review, provided such outside consultants first sign the certification in Attachment A.

13. **Restriction on Copying by Commission Staff, OPUC and the OAG**. Except as allowed by Paragraph 7, Commission Staff, OPUC and the OAG may not make additional copies of the Highly Sensitive Protected Materials furnished to them unless the producing party agrees in writing otherwise, or, upon a showing of good cause, the presiding officer directs otherwise. Commission Staff, OPUC, and the OAG may make limited notes of Highly Sensitive Protected Materials furnished to them, and all such handwritten notes will be treated as Highly Sensitive Protected Materials as are the materials from which the notes are taken.

14. **Public Information Requests**. In the event of a request for any of the Highly Sensitive Protected Materials under the Public Information Act, an authorized representative of the Commission, OPUC, or the OAG may furnish a copy of the requested Highly Sensitive Protected Materials to the Open Records Division at the OAG together with a copy of this Protective Order after notifying the producing party that such documents are being furnished to the OAG. Such notification may be provided simultaneously with the delivery of the Highly Sensitive Protected Materials to the OAG.

15. **Required Certification**. Each person who inspects the Protected Materials shall, before such inspection, agree in writing to the following certification found in Attachment A to this Protective Order:

> I certify my understanding that the Protected Materials are provided to me pursuant to the terms and restrictions of the Protective Order in this docket, and that I have been given a copy of it and have read the Protective Order and agree to be bound by it. I understand that the contents of the Protected Materials, any notes, memoranda, or

> any other form of information regarding or derived from the Protected Materials shall not be disclosed to anyone other than in accordance with the Protective Order and, unless I am an employee of the Commission or OPUC, shall be used only for the purpose of the proceeding in Docket No. 55255. I acknowledge that the obligations imposed by this certification are pursuant to such Protective Order. Provided, however, if the information contained in the Protected Materials is obtained from independent public sources, the understanding stated herein shall not apply.

In addition, Reviewing Representatives who are permitted access to Highly Sensitive Protected Material under the terms of this Protective Order shall, before inspection of such material, agree in writing to the following certification found in Attachment A to this Protective Order:

> I certify that I am eligible to have access to Highly Sensitive Protected Material under the terms of the Protective Order in this docket.

A copy of each signed certification shall be provided by the Reviewing Party to Counsel for the producing party and served upon all parties of record.

16. **Disclosures between Reviewing Representatives and Continuation of Disclosure Restrictions after a Person is no Longer Engaged in the Proceeding**. Any Reviewing Representative may disclose Protected Materials, other than Highly Sensitive Protected Materials, to any other person who is a Reviewing Representative provided that, if the person to whom disclosure is to be made has not executed and provided for delivery of a signed certification to the party asserting confidentiality, that certification shall be executed prior to any disclosure. A Reviewing Representative may disclose Highly Sensitive Protected Material to other Reviewing Representatives who are permitted access to such material and have executed the additional certification required for persons who receive access to Highly Sensitive Protected Material. In the event that any Reviewing Representative to whom Protected Materials are disclosed ceases to be engaged in these proceedings, access to Protected Materials by that person shall be terminated and all notes, memoranda, or other information derived from the protected material shall either be destroyed or given to another Reviewing Representative of that party who is authorized pursuant to this Protective Order to receive the protected materials. Any person who has

agreed to the foregoing certification shall continue to be bound by the provisions of this Protective Order so long as it is in effect, even if no longer engaged in these proceedings.

17. **Producing Party to Provide One Copy of Certain Protected Material and Procedures for Making Additional Copies of Such Materials**. Except for Highly Sensitive Protected Materials, which shall be provided to the Reviewing Parties pursuant to Paragraphs 9 and 11, and voluminous Protected Materials, the producing party shall provide a Reviewing Party one copy of the Protected Materials upon receipt of the signed certification described in Paragraph 15. Except for Highly Sensitive Protected Materials, a Reviewing Party may make further copies of Protected Materials for use in this proceeding pursuant to this Protective Order, but a record shall be maintained as to the documents reproduced and the number of copies made, and upon request the Reviewing Party shall provide the party asserting confidentiality with a copy of that record.

18. **Procedures Regarding Voluminous Protected Materials**. 16 Texas Administrative Code (TAC) § 22.144(h) will govern production of voluminous Protected Materials. Voluminous Protected Materials will be made available in the producing party's voluminous room, in Austin, Texas, or at a mutually agreed upon location, Monday through Friday, 9:00 a.m. to 5:00 p.m. (except on state or Federal holidays), and at other mutually convenient times upon reasonable request.

19. **Reviewing Period Defined**. The Protected Materials may be reviewed only during the Reviewing Period, which shall commence upon entry of this Protective Order and continue until the expiration of the Commission's plenary jurisdiction. The Reviewing Period shall reopen if the Commission regains jurisdiction due to a remand as provided by law. Protected materials that are admitted into the evidentiary record or accompanying the evidentiary record as offers of proof may be reviewed throughout the pendency of this proceeding and any appeals.

20. **Procedures for Making Copies of Voluminous Protected Materials**. Other than Highly Sensitive Protected Materials, Reviewing Parties may take notes regarding the information contained in voluminous Protected Materials made available for inspection or they may

make photographic, mechanical or electronic copies of the Protected Materials, subject to the conditions in this Protective Order; provided, however, that before photographic, mechanical or electronic copies may be made, the Reviewing Party seeking photographic, mechanical or electronic copies must provide written confirmation of the receipt of copies listed on Attachment B of this Protective Order identifying each piece of Protected Materials or portions thereof the Reviewing Party will need.

21. **Protected Materials to be Used Solely for the Purposes of These Proceedings**. All Protected Materials shall be made available to the Reviewing Parties and their Reviewing Representatives solely for the purposes of these proceedings. Access to the Protected Materials may not be used in the furtherance of any other purpose, including, without limitation: (a) any other pending or potential proceeding involving any claim, complaint, or other grievance of whatever nature, except appellate review proceedings that may arise from or be subject to these proceedings; or (b) any business or competitive endeavor of whatever nature. Because of their statutory regulatory obligations, these restrictions do not apply to Commission Staff or OPUC.

22. **Procedures for Confidential Treatment of Protected Materials and Information Derived from Those Materials**. Protected Materials, as well as a Reviewing Party's notes, memoranda, or other information regarding or derived from the Protected Materials are to be treated confidentially by the Reviewing Party and shall not be disclosed or used by the Reviewing Party except as permitted and provided in this Protective Order. Information derived from or describing the Protected Materials shall be maintained in a secure place and shall not be placed in the public or general files of the Reviewing Party except in accordance with the provisions of this Protective Order. A Reviewing Party must take all reasonable precautions to ensure that the Protected Materials including notes and analyses made from Protected Materials that disclose Protected Materials are not viewed or taken by any person other than a Reviewing Representative of a Reviewing Party.

23. **Procedures for Submission of Protected Materials**. If a Reviewing Party tenders for filing any Protected Materials, including Highly Sensitive Protected Materials, or any written testimony, exhibit, brief, motion or other type of pleading or other submission at

the Commission or before any other judicial body that quotes from Protected Materials or discloses the content of Protected Materials, the confidential portion of such submission shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they contain Protected Material or Highly Sensitive Protected Material and are sealed pursuant to this Protective Order. If filed at the Commission, such documents shall be marked "PROTECTED MATERIAL" and shall be filed under seal with the presiding officer and served under seal to the counsel of record for the Reviewing Parties. The presiding officer may subsequently, on his/her own motion or on motion of a party, issue a ruling respecting whether or not the inclusion, incorporation, or reference to Protected Materials is such that such submission should remain under seal. If filing before a judicial body, the filing party: (a) shall notify the party which provided the information within sufficient time so that the producing party may seek a temporary sealing order; and (b) shall otherwise follow the procedures in Rule 76a, Texas Rules of Civil Procedure.

24. **Maintenance of Protected Status of Materials during Pendency of Appeal of Order Holding Materials are not Protected Materials**. In the event that the presiding officer at any time in the course of this proceeding finds that all or part of the Protected Materials are not confidential or proprietary, by finding, for example, that such materials have entered the public domain or materials claimed to be Highly Sensitive Protected Materials are only Protected Materials, those materials shall nevertheless be subject to the protection afforded by this Protective Order for three (3) full working days, unless otherwise ordered, from the date the party asserting confidentiality receives notice of the presiding officer's order. Such notification will be by written communication. This provision establishes a deadline for appeal of a presiding officer's order to the Commission. In the event an appeal to the Commissioners is filed within those three (3) working days from notice, the Protected Materials shall be afforded the confidential treatment and status provided in this Protective Order during the pendency of such appeal. Neither the party asserting confidentiality, nor any Reviewing Party waives its right to seek additional administrative or judicial remedies after the Commission's denial of any appeal.

25. **Notice of Intent to Use Protected Materials or Change Materials Designation**. Parties intending to use Protected Materials shall notify the other parties prior to offering them into evidence or otherwise disclosing such information into the record of the proceeding. During the pendency of Docket No. 57463 at the Commission, in the event that a Reviewing Party wishes to disclose Protected Materials to any person to whom disclosure is not authorized by this Protective Order, or wishes to have changed the designation of certain information or material as Protected Materials by alleging, for example, that such information or material has entered the public domain, such Reviewing Party shall first file and serve on all parties written notice of such proposed disclosure or request for change in designation, identifying with particularity each of such Protected Materials. A Reviewing Party shall at any time be able to file a written motion to challenge the designation of information as Protected Materials.

26. **Procedures to Contest Disclosure or Change in Designation**. In the event that the party asserting confidentiality wishes to contest a proposed disclosure or request for change in designation, the party asserting confidentiality shall file with the appropriate presiding officer its objection to a proposal, with supporting affidavits, if any, within five (5) working days after receiving such notice of proposed disclosure or change in designation. Failure of the party asserting confidentiality to file such an objection within this period shall be deemed a waiver of objection to the proposed disclosure or request for change in designation. Within five (5) working days after the party asserting confidentiality files its objection and supporting materials, the party challenging confidentiality may respond. Any such response shall include a statement by counsel for the party challenging such confidentiality that he or she has reviewed all portions of the materials in dispute and, without disclosing the Protected Materials, a statement as to why the Protected Materials should not be held to be confidential under current legal standards, or that the party asserting confidentiality for some reason did not allow such counsel to review such materials. If either party wishes to submit the material in question for in camera inspection, it shall do so no later than five (5) working days after the party challenging confidentiality has made its written filing.

27. **Procedures for Presiding Officer Determination Regarding Proposed Disclosure or Change in Designation**. If the party asserting confidentiality files an objection, the appropriate presiding officer will determine whether the proposed disclosure or change in designation is appropriate. Upon the request of either the producing or Reviewing Party or upon the presiding officer's own initiative, the presiding officer may conduct a prehearing conference. The burden is on the party asserting confidentiality to show that such proposed disclosure or change in designation should not be made. If the presiding officer determines that such proposed disclosure or change in designation should be made, disclosure shall not take place earlier than three (3) full working days after such determination unless otherwise ordered. No party waives any right to seek additional administrative or judicial remedies concerning such presiding officer's ruling.

28. **Maintenance of Protected Status during Periods Specified for Challenging Various Orders**. Any party electing to challenge, in the courts of this state, a Commission or presiding officer determination allowing disclosure or a change in designation shall have a period of ten (10) days from: (a) the date of an unfavorable Commission order; or (b) if the Commission does not rule on an appeal of an interim order, the date an appeal of an interim order to the Commission is overruled by operation of law, to obtain a favorable ruling in state district court. Any party challenging a state district court determination allowing disclosure or a change in designation shall have an additional period of ten (10) days from the date of the order to obtain a favorable ruling from a state appeals court. Finally, any party challenging a determination of a state appeals court allowing disclosure or a change in designation shall have an additional period of ten (10) days from the date of the order to obtain a favorable ruling from the state supreme court, or other appellate court. All Protected Materials shall be afforded the confidential treatment and status provided for in this Protective Order during the periods for challenging the various orders referenced in this paragraph. For purposes of this paragraph, a favorable ruling of a state district court, state appeals court, Supreme Court or other appellate court includes any order extending the deadlines in this paragraph.

29. **Other Grounds for Objection to Use of Protected Materials Remain Applicable**. Nothing in this Protective Order shall be construed as precluding any party from objecting to the use of Protected Materials on grounds other than confidentiality, including the lack of required relevance. Nothing in this Protective Order constitutes a waiver of the right to argue for more disclosure, provided, however, that unless the Commission or a court orders such additional disclosure, all parties will abide by the restrictions imposed by the Protective Order.

30. **Protection of Materials from Unauthorized Disclosure**. All notices, applications, responses, or other correspondence shall be made in a manner which protects Protected Materials from unauthorized disclosure.

31. **Return of Copies of Protected Materials and Destruction of Information Derived from Protected Materials**. Following the conclusion of these proceedings, each Reviewing Party must, no later than thirty (30) days following receipt of the notice described below, return to the party asserting confidentiality all copies of the Protected Materials provided by that party pursuant to this Protective Order and all copies reproduced by a Reviewing Party, and counsel for each Reviewing Party must provide to the party asserting confidentiality a letter by counsel that, to the best of his or her knowledge, information, and belief, all copies of notes, memoranda, and other documents regarding or derived from the Protected Materials (including copies of Protected Materials) that have not been so returned, if any, have been destroyed, other than notes, memoranda, or other documents which contain information in a form which, if made public, would not cause disclosure of the substance of Protected Materials. As used in this Protective Order, "conclusion of these proceedings" refers to the exhaustion of available appeals, or the running of the time for the making of such appeals, as provided by applicable law. If, following any appeal, the Commission conducts a remand proceeding, then the "conclusion of these proceedings" is extended by the remand to the exhaustion of available appeals of the remand, or the running of the time for making such appeals of the remand, as provided by applicable law. Promptly following the conclusion of these proceedings, counsel for the party asserting confidentiality will send a written notice to all other parties, reminding

them of their obligations under this paragraph. Nothing in this paragraph shall prohibit counsel for each Reviewing Party from retaining two (2) copies of any filed testimony, brief, application for rehearing, hearing exhibit or other pleading which refers to Protected Materials provided that any such Protected Materials retained by counsel shall remain subject to the provisions of this Protective Order.

32. **Applicability of Other Law**. This Protective Order is subject to the requirements of the Public Information Act, the Open Meetings Act,[3] the Texas Securities Act[4] and any other applicable law, provided that parties subject to those acts will notify the party asserting confidentiality, if possible, under those acts, prior to disclosure pursuant to those acts. Such notice shall not be required where the Protected Materials are sought by governmental officials authorized to conduct a criminal or civil investigation that relates to or involves the Protected Materials, and those governmental officials aver in writing that such notice could compromise the investigation and that the governmental entity involved will maintain the confidentiality of the Protected Materials.

33. **Procedures for Release of Information under Order**. If required by order of a governmental or judicial body, the Reviewing Party may release to such body the confidential information required by such order; provided, however, that: (a) the Reviewing Party shall notify the producing party of the order requiring the release of such information within five (5) calendar days of the date the Reviewing Party has notice of the order; (b) the Reviewing Party shall notify the producing party at least five (5) calendar days in advance of the release of the information to allow the producing party to contest any release of the confidential information; and (c) the Reviewing Party shall use its best efforts to prevent such materials from being disclosed to the public. The terms of this Protective Order do not preclude the Reviewing Party from complying with any valid and enforceable order of a state or federal court with competent jurisdiction specifically requiring disclosure of Protected Materials earlier than contemplated herein. The notice

[3] Tex. Gov't Code §§ 551.001–.146.

[4] *Id.* §§ 4001.001–4008.105.

specified in this section shall not be required where the Protected Materials are sought by governmental officials authorized to conduct a criminal or civil investigation that relates to or involves the Protected Materials, and those governmental officials aver in writing that such notice could compromise the investigation and that the governmental entity involved will maintain the confidentiality of the Protected Materials.

34. **Best Efforts Defined**. The term "best efforts" as used in the preceding paragraph requires that the Reviewing Party attempt to ensure that disclosure is not made unless such disclosure is pursuant to a final order of a Texas governmental or Texas judicial body, the written opinion of the Texas Attorney General sought in compliance with the Public Information Act, or the request of governmental officials authorized to conduct a criminal or civil investigation that relates to or involves the Protected Materials. The Reviewing Party is not required to delay compliance with a lawful order to disclose such information but is simply required to timely notify the party asserting confidentiality, or its counsel, that it has received a challenge to the confidentiality of the information and that the Reviewing Party will either proceed under the provisions of § 552.301 of the Public Information Act or intends to comply with the final governmental or court order. Provided, however, that no notice is required where the Protected Materials are sought by governmental officials authorized to conduct a criminal or civil investigation that relates to or involves the Protected Materials, and those governmental officials aver in writing that such notice could compromise the investigation and that the governmental entity involved will maintain the confidentiality of the Protected Materials.

35. **Notify Defined**. "Notify" for purposes of Paragraphs 32, 33, and 34 means written notice to the party asserting confidentiality at least five (5) calendar days prior to release; including when a Reviewing Party receives a request under the Public Information Act. However, the Commission, OAG, or OPUC may provide a copy of Protected Materials to the Open Records Division of the OAG as provided herein.

36. **Requests for Non-Disclosure**. If the producing party asserts that the requested information should not be disclosed at all or should not be disclosed to certain parties under the protection afforded by this Protective Order, the producing party shall tender the

information for in camera review to the presiding officer within ten (10) calendar days of the request. At the same time, the producing party shall file and serve on all parties its argument, including any supporting affidavits, in support of its position of non-disclosure. The burden is on the producing party to establish that the material should not be disclosed. The producing party shall serve a copy of the information under the classification of Highly Sensitive Protected Material to all parties requesting the information that the producing party has not alleged should be prohibited from reviewing the information.

Parties wishing to respond to the producing party's argument for non-disclosure shall do so within five working days. Responding parties should explain why the information should be disclosed to them, including why disclosure is necessary for a fair adjudication of the case if the material is determined to constitute a trade secret. If the presiding officer finds that the information should be disclosed as Protected Material under the terms of this Protective Order, the presiding officer shall stay the order of disclosure for such period of time as the presiding officer deems necessary to allow the producing party to appeal the ruling to the Commission.

37. **Sanctions Available for Abuse of Designation**. If the presiding officer finds that a producing party unreasonably designated material as Protected Material or as Highly Sensitive Protected Material, or unreasonably attempted to prevent disclosure pursuant to Paragraph 36, the presiding officer may sanction the producing party pursuant to 16 TAC § 22.161.

38. **Modification of Protective Order**. Each party shall have the right to seek changes in this Protective Order as appropriate from the presiding officer.

39. **Breach of Protective Order**. In the event of a breach of the provisions of this Protective Order, the producing party, if it sustains its burden of proof required to establish the right to injunctive relief, shall be entitled to an injunction against such breach without any requirements to post bond as a condition of such relief. The producing party shall not be relieved of proof of any element required to establish the right to injunctive relief. In

addition to injunctive relief, the producing party shall be entitled to pursue any other form of relief to which it is entitled.

ATTACHMENT A to Protective Order

Protective Order Certification

I certify my understanding that the Protected Materials are provided to me pursuant to the terms and restrictions of the Protective Order in this docket and that I have received a copy of it and have read the Protective Order and agree to be bound by it. I understand that the contents of the Protected Materials, any notes, memoranda, or any other form of information regarding or derived from the Protected Materials shall not be disclosed to anyone other than in accordance with the Protective Order and, unless I am an employee of the Commission or OPUC, shall be used only for the purpose of the proceeding in Docket No. 57463. I acknowledge that the obligations imposed by this certification are pursuant to such Protective Order. Provided, however, if the information contained in the Protected Materials is obtained from independent public sources, the understanding stated here shall not apply.

Signature	Party Represented
Printed Name	Date

I certify that I am eligible to have access to Highly Sensitive Protected Material under the terms of the Protective Order in this docket.

Signature	Party Represented
Printed Name	Date

ATTACHMENT B to Protective Order

I request to view/copy the following documents:

Document Requested	# of Copies	Non-Confidential	Protected Materials and/or Highly Sensitive Protected Materials

Signature

Party Represented

Printed Name

Date

CERTIFICATE OF SERVICE

I hereby certify that on this 31st day of December, 2024, a true and correct copy of the foregoing was provided to Commission Staff, the Office of Public Utility Counsel, and the parties described in Section VI of this Application by electronic mail, first class mail or overnight delivery, in accordance with the Commission's Second Order Suspending Rules issued on July 16, 2020, in Project No. 50664.

/s/ Scottie Agnew

Scottie Agnew

DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§ § § § § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY
of
ADRIAN J. RODRIGUEZ

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

(Filename: RodriguezTXDirect.docx; *Total Pages:* 17)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
C&I	Commercial and Industrial
Commission or PUCT	Public Utility Commission of Texas
ERCOT	Electric Reliability Council of Texas
EDM	EDM International, Inc.
NARUC	National Association of Regulatory Utility Commissioners
SPS	Southwestern Public Service Company, a New Mexico corporation
SRP or Plan	System Resiliency Plan
Xcel Energy	Xcel Energy Inc.

DIRECT TESTIMONY
OF
ADRIAN J. RODRIGUEZ

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name, current position, and business address.

A. My name is Adrian J. Rodriguez. I am the President of Southwestern Public Service Company ("SPS"), a New Mexico corporation, and a wholly owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy"). My business address is 790 South Buchanan Street, Amarillo, Texas 79101.

Q. How long have you worked for SPS?

A. I have worked for SPS since June 2022.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of SPS.

Q. Have you testified previously?

A. Yes. I testified on behalf of SPS before the Public Utility Commission of Texas ("Commission") in SPS's most recent base rate case in Docket No. 54634 and before the New Mexico Public Regulation Commission in Case No. 22-00286-UT. I have also testified or appeared before the Washington Utilities and Transportation Commission on behalf of another company.

II. EXECUTIVE SUMMARY

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to introduce and support the System Resiliency Plan ("SRP" or the "Plan") that SPS is proposing in this proceeding. In support of the proposed SRP investments, I describe SPS, including the unique characteristics of its service territory and customer makeup; certain resiliency events that pose a particular risk to the SPS system; SPS's longstanding commitment to resiliency; and activities that SPS is currently undertaking to enhance the resilience of its system.

Q. Please generally describe SPS's SRP.

A. SPS's resiliency plan is focused on providing cost effective resiliency measures that will enable the SPS system to withstand and recover rapidly from the most common and highest impact weather events on the SPS system as well as mitigate the wildfire risks present in the Texas Panhandle and South Plains. As detailed in SPS's SRP document and in SPS's filed testimony, SPS's proposed measures include Distribution Overhead Hardening, Distribution System Protection Modernization, Communication Modernization, Operational Flexibility, and Wildfire Mitigation. Overall, SPS's SRP represents approximately $538.3 million of system investment that benefits customers by introducing new programs that enhance system operations, improve public safety, and harden the distribution network as weather-related resiliency risks evolve. SPS's evaluation of Plan performance is metric-based and utilizes a continuous improvement strategy to

resiliency planning. This initial SRP is balanced to address the highest risks to SPS's system while also providing the right foundation for future resiliency measures.

III. SPS INTRODUCTION

Q. Please describe SPS.

A. SPS is an electric utility headquartered in Amarillo, Texas, that employs approximately 1,100 people. SPS and its predecessors have provided electric service to customers in the Panhandle and South Plains of Texas for over 100 years. Today, SPS generates, transmits, distributes, and sells electricity to customers in Texas and New Mexico. SPS is a member of the Southwest Power Pool regional transmission organization and is synchronously connected to the Eastern Interconnection electric grid. SPS is also connected to the Western Interconnection electric grid through three high-voltage direct-current converters. Although SPS operates adjacent to the Electric Reliability Council of Texas ("ERCOT") electric grid, it has no direct interconnections with ERCOT. At SPS, we know that the economic growth and prosperity of our communities depends on our ability to deliver electricity to our customers when and where they need it, while keeping customer bills as low as possible. We also know it is our job to plan and prepare for the future. This Plan is intended to offer our recommended actions and investment for the resiliency of the system so that we can continue to provide safe and reliable electricity to support our region.

Q. Please describe SPS's service area.

A. SPS serves customers across a vast area of land covering both Texas and New Mexico. SPS's total service area encompasses a 52,000-square-mile area in the Texas Panhandle, the Texas South Plains, and eastern and southeastern New Mexico. It extends approximately 400 miles from north to south and 200 miles from east to west. This equates to approximately 33.3 million acres of land, much of which is rural. SPS's rural expanses are interspersed with sizable population centers, including Amarillo and Lubbock (which is served by Lubbock Power & Light in ERCOT) in Texas, and Roswell and Hobbs, New Mexico.

SPS serves 96 incorporated communities, 80 of which are in Texas, and provides retail electric service to approximately 406,000 customers, including approximately 280,000 retail electric customers in Texas.

Q. Please describe the SPS electric system.

A. As described above, SPS's electric system is expansive and covers customers in both Texas and New Mexico. In developing this Plan, SPS considered its entire retail customer base, and proposes measures and programs to enhance the resiliency of the SPS electric system as a whole. The SRP is developed to address the unique needs of our Texas geography and service area.

SPS has fossil fuel and renewable generation, and its electric system is comprised of approximately 24,500 miles of overhead and underground transmission and distribution lines and 449 electric substations. Of those facilities, approximately 17,300 miles of transmission and distribution lines and over 360 substations are located in Texas.

Q. Please describe any unique characteristics of SPS's customers.

A. Due to the largely rural character of SPS's expansive service territory, SPS's customer density is far lower than many other Texas utilities. Functionally, this means that SPS will have fewer customers per mile of distribution line. However, while SPS's customer density may be lower, the impact of SPS's service territory on Texas and its economy is substantial. SPS serves key industries, and our customers provide resources that are vital to the success of Texas and the nation and require reliable electric service to do so. SPS takes this responsibility to provide reliable electric service seriously and has developed this Plan with its unique customer base, in Texas and New Mexico, at the forefront of its discussions and decisions.

Q. What is SPS's customer make-up and why is it significant?

A. Unlike many Texas electric utilities, the load on SPS's system is predominantly commercial and industrial ("C&I"). While residential customers comprise 79% of SPS's total customer count, they account for only 13% of the load on the SPS system. Regardless, our residential customers benefit from a resilient electric system that continues to keep the lights on in their homes, in the schools where they send their children, in the retail and grocery stores where they shop, and at their places of work, whether it is a small commercial organization, government office, or large C&I company. SPS witness Brianne R. Jole, Manager of System Planning and Strategy, describes in her direct testimony how SPS factored the amount of C&I load on the SPS system into the development of the Plan's measures and programs.

Because C&I customers account for such a large portion of SPS's sales, SPS's provision of safe, reliable electricity supports the Texas economy. Our ability to keep the energy flowing impacts our C&I customers, their employees, their own customers, and, consequently, other major sectors of the State's economy.

This unique customer mix both informed and shaped the Plan. SPS witness Jason D. De Stigter explains how this customer mix factored into the benefit-cost analysis our consultant, 1898 & Co., performed.

Q. Are SPS's commercial and industrial customers particularly vulnerable to resiliency events?

A. Yes. SPS's C&I customers provide essential services, commodities, and goods that significantly contribute to local and state economies. Resiliency events can cause unplanned outages which present safety risks for C&I employees. They also expose C&I customers to potential loss of material and revenue, breakdown of machinery, and delays of necessary goods and services in both production and delivery.

Q. Are SPS's residential customers vulnerable to resiliency events?

A. Yes. Our neighbors rely on SPS's electric system for the energy they need in their daily lives. In particular, a resilient electric system allows our communities to manage through an emergency and recover from an extreme event safely and quickly. During and following an extreme weather event or community emergency, the availability of electric service allows residents to communicate with each other, stay updated on instructions from governmental authorities, or evacuate a region in an orderly manner. Working traffic signals allow law enforcement and first responders to maintain focus on those in need. Hospitals can address the needs of

patients, knowing that electric service is available and allowing them to conserve their own back-up generators. A resilient electric system allows our customers to weather storms and allows our communities to address emergencies when they occur and rebuild quicker when there is damage.

Q. What types of extreme events regularly affect SPS's system and can impact its resiliency?

A. Due to the geography of SPS's system, SPS faces unpredictable, intense, and, often times, compounding weather events, ranging from icing and blizzards to extreme heat and drought, flooding, high winds, and tornadoes. These weather conditions, especially drought and high winds, also increase the likelihood and destructiveness of wildfires in the region.

Q. Have there been recent weather events that affected the resiliency of SPS's system?

A. Yes. Over the last decade, major weather events have impacted the United States with increasing frequency and intensity. In just the last two years, customers across SPS's Texas system have endured extreme weather events including floods, tornado-force straight-line winds, and ice storms. For example, SPS's communities experienced extreme non-thunderstorm winds of over 70 miles per hour outside of Pampa in February 2023, severe flooding that required evacuations in Hereford and Amarillo in May and June 2023, a devastating tornado that struck Perryton on June 15, 2023, severe drought near Dalhart in the summer of 2023, and a blizzard with sustained winds of 35 to 45 miles per hour and 74 mile per hour wind gusts in January 2024. The direct testimony of SPS witness Mr. De Stigter of 1898 & Co.

includes a table showing improvements to customer outage data associated with resiliency events such as these under the SRP.

Q. Is mitigating wildfire risk part of SPS's Plan to increase resiliency?

A. Yes. In addition to the risks weather events pose to electric systems, utility infrastructure itself can cause or contribute to wildfire risk, and we understand this issue. Given that approximately 64 percent of SPS's system is located in either Tiers 2 or 3 wildfire risk areas, wildfire is a continual area of focus. Our coworkers had to contend with multiple fires that impacted our families, friends, and neighbors in late February 2024, when the Texas Panhandle was devastated by a series of wildfires collectively called the Amarillo Complex Fires. SPS acknowledged that our equipment appeared to be involved in two ignitions of the Smokehouse Creek Fire and the smaller Reamer Fire, which we believe burned into or merged into the footprint of the Smokehouse Creek Fire. Our thoughts continue to be with our friends, families, and neighbors who were impacted. Our industry is evolving, and so are we.

The National Association of Regulatory Utility Commissioners ("NARUC"), of which members of this Commission participate, recently passed a resolution entitled Wildfire Impacts on Utility Customer Reliability and Affordability, recognizing that fires are increasing in frequency and intensity across North America and electric utility infrastructure, such as distribution and transmission lines, is susceptible to damage that can lead to ignition or contribute

to an existing ignition during high wind events.[1] The NARUC resolution also recognized that electric utilities are working to address their wildfire risk through increased situational awareness and grid investments to reduce the likelihood of their infrastructure causing an ignition, thereby limiting impacts to customers. SPS is committed to doing what it can to reduce the likelihood of wildfires in the future. With the increasing wildfire activity experienced in the SPS service area, and across the country, SPS's determination to promptly allocate its time and resources to protect against wildfire loss, ignition, and spread has only increased in urgency. Evidence of this can be seen in our Accelerated Pole Replacement Program and Enhanced Power Safety Settings, initiated earlier this year, and other initiatives. SPS is committed to continuing and advancing its wildfire mitigation efforts to protect its customers and provide them with reliable service.

As I testified before the House Interim Committee on The Panhandle Wildfires on April 4, 2024, and House Committee on State Affairs on September 17, 2024, SPS committed to the Texas Legislature that its SRP will directly address the wildfire risks to the Panhandle. In keeping with this promise and SPS's overall policy relating to wildfire risk mitigation, this SRP proposes numerous measures specific to improving SPS's resiliency and mitigation of wildfire risk.

While SPS has not waited to address wildfire risk, the proposed new investment within the Plan will allow SPS to accelerate mitigation efforts given the evolving risk and significant wildfire effects experienced in our communities. In

[1] *See* National Association of Regulatory Utility Commissioners ("NARUC*"), Resolutions Passed by the NARUC Board of Directors at the November 10-13, 2024 NARUC Annual Meeting and Education Conference In Anaheim, California, Resolution of Wildfire Impacts on Utility Customer Reliability and Affordability*, 4-6 (Nov. 2024), available at 812873F4-E348-B77F-4D75-E513FF13A86D.

addition to the resiliency measures that inherently mitigate wildfire risk, this Plan includes various programs addressing wildfire as a standalone resiliency event. Proposed measures will strengthen and amplify SPS's wildfire mitigation efforts by enhancing predictive modeling, system monitoring, and associated identification and detection capabilities. The measures also reduce risk that SPS assets will cause an ignition, increase periodic inspections, and upgrade communication capabilities for protection, response, and recovery when an event occurs.

In their direct testimonies, SPS witness Anne Z. Sherwood, Area Vice President of Wildfire Mitigation: Regulatory and Policy, discusses SPS's existing wildfire approach and programs as well as those proposed in the SRP, and SPS witness Ryan Brockbank with EDM International, Inc. ("EDM") discusses the development of SPS's Wildfire Risk Maps[2] that informed the establishment of SPS's Wildfire Risk Tiers, which is a foundational component of the project prioritization framework SPS has utilized in the development of its SRP along with third-party modeled benefit-cost ratios.

Q. What makes wildfires significant as a resiliency event?

A. Extreme weather and other resiliency events all pose external risks to electric facilities, meaning that those facilities are subjected to damage, potentially resulting in customer outages and restoration work. But, when extreme weather damages the electric system in a manner that can cause the ignition of a wildfire, the electric facilities can contribute to that danger and exacerbate risks to property and public safety. A recently published S&P Global Analyst Comment discussed that for

[2] In general, the terms Wildfire Risk Map and Wildfire Operations Map are used interchangeably in direct testimony and in the SRP.

utilities "most exposed to material wildfire risks, comprehensive mitigation and effective wildfire management plans are clearly important to managing wildfire risks."[3] Accordingly, the Plan proposed in this proceeding comprehensively targets wildfire-related risks, addressing both external risk to SPS facilities and the risk of SPS facilities causing an ignition. SPS's wildfire-prevention philosophy and programs are addressed in more detail in the direct testimonies of SPS witnesses Ms. Sherwood and Ms. Jole.

IV. ACTIONS SPS HAS TAKEN TOWARDS SYSTEM RESILIENCY INDEPENDENT OF THE SRP

Q. Prior to development of its SRP, did SPS prioritize the resiliency of its system?

A. Yes. SPS has a long history of providing safe, reliable, value-added service to our customers. We have made significant investments to ensure our Texas customers receive the reliable electric service they need and expect. When SPS has been affected by resiliency events, such as Winter Storm Finn in 2024 or the Smokehouse Creek Fire, it has taken lessons from the past seriously and adopted strategic measures to avoid future risks.

For example, in the wake of the Smokehouse Creek Fire, SPS modified its policy for the timing of pole replacements. This was a pledge I made to the Texas Legislature and communities. Now, SPS replaces certain poles identified as needing emergency replacement within days of inspection, thereby reducing the time poles known to be nearing the end of their life will be on the system. Similarly, SPS has adopted a policy of not re-energizing lines contacted by a foreign object

[3] Loughlin & Babitsch, *Wildfire-Exposed U.S. Investor-Owned Utilities Face Increasing Credit Risks Without Comprehensive Solutions*, S&P GLOBAL (Nov. 6, 2024), https://www.spglobal.com/ratings/en/research/articles/241106-wildfire-exposed-u-s-investor-owned-utilities-face-increasing-credit-risks-without-comprehensive-solutions-13297812.

on high wildfire-risk days until the lines have been patrolled. Recently, SPS announced the initial deployment of cameras to assess the landscape and coordinate with first responders to address potential wildfires, no matter the cause. This responsiveness is part of SPS's culture and commitment to our customers. Actions like these, along with the proposed measures in this SRP, demonstrate our commitment to improving the resiliency of the SPS system.

V. RESILIENCY-FOCUSED INVESTMENT PROPOSED IN THE SRP

Q. How does resiliency planning presented in this SRP differ from resiliency planning SPS does in the ordinary course of business?

A. The Texas Legislature enacted House Bill 2555, codified in Section 38.078 of the Public Utility Regulatory Act, to encourage Texas electric utilities to prioritize resiliency of their transmission and distribution systems by allowing utilities to file and seek approval for system resiliency plans. HB 2555 presents a unique opportunity for Texas electric utilities to prioritize system resiliency to a degree that regulatory cost-recovery mechanisms and utility capital budgets would otherwise struggle to support. SPS advocated for HB 2555 and greatly appreciates the opportunity to present our Plan to the Commission for consideration. The proposed Plan includes new programs and incremental investments tailored to work in conjunction with existing resiliency-related programs to enhance the resiliency of SPS's system.

Q. What priorities drove SPS's decision-making during the development of the SRP?

A. We view this SRP as an opportunity to supplement existing resiliency efforts and add improvements to the system beyond those to which we have already committed.

Further, the five proposed measures are interrelated, focus primarily on SPS's distribution system, and provide quantified resiliency benefits to customers in the form of reduced frequency and duration of outages, avoided restoration costs, wildfire risk mitigation, and improved service quality in areas of lower performance. Concurrently, we are always mindful of our obligation to provide cost-effective electric service to our customers. Therefore, SPS has worked with experts internally, in addition to external, third-party consulting firms, to analyze data and direct investments to areas of the system with elevated wildfire risk together with leveraging third-party modeled benefit-cost ratios to prioritize projects that target the greatest resiliency risks (i.e., SPS's project prioritization framework). SPS's planning process, prioritization framework, and systematic implementation approach are discussed in detail by the other witnesses, including SPS witnesses Casey S. Meeks, Wendall A. Reimer, Ms. Jole, Ms. Sherwood, and SPS witness Mr. De Stigter of 1898 & Co. SPS witness Brooke A. Trammell, SPS Regional Vice President of Regulatory and Pricing, also provides an overview of the Plan and formally introduces our colleagues and the scope of their testimonies.

VI. RELIEF REQUESTED

Q. Please summarize the relief SPS is seeking in this proceeding.

A. As recognized by the Texas Legislature and the Commission, the time has come for SPS to accelerate investments to enhance resiliency. While SPS's investment in resiliency requires careful balancing of customer outage risk and cost, SPS agrees with the legislative mandate to increase the resiliency of its system through its proposed Distribution Overhead Hardening, Distribution System Protection

Modernization, Communication Modernization, Operational Flexibility, and Wildfire Mitigation measures. The measures proposed in SPS's Plan and discussed in its supporting testimony demonstrate these investments are in the public interest and SPS requests the Commission approve them. As Ms. Trammell discusses in her direct testimony, SPS is not seeking a cost-recovery rider at this time but is seeking approval of the Plan and will defer appropriate costs in a regulatory asset.

Q. Does this conclude your direct testimony?

A. Yes.

AFFIDAVIT

STATE OF TEXAS)
)
COUNTY OF POTTER)

ADRIAN J. RODRIGUEZ, first being sworn on his oath, states:

I am the witness identified in the preceding testimony. I am over 18 years of age, of sound mind, and am capable of making this affidavit. I have read the testimony and the accompanying attachments and am familiar with the contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

ADRIAN J. RODRIGUEZ

Subscribed and sworn to before me this 27th day of December 2024 by ADRIAN J. RODRIGUEZ.

MARY C. JOHNSON
Notary Public, State of Texas
Comm. Expires 08-28-2028
Notary ID 12084834

Notary Public, State of Texas

My Commission Expires: 8.28.2028

DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF A TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§ § § § §**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY
of
BROOKE A. TRAMMELL

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

(Filename: TrammellSRPDirect.docx; *Total Pages:* 36)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
Commission or PUCT	Public Utility Commission of Texas
DCRF	Distribution Cost Recovery Factor
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GRIP	Grid Resilience and Innovative Partnerships
IEEE	Institute of Electrical and Electronics Engineers
O&M	Operations and Maintenance
PSCo	Public Service Company of Colorado, a Colorado corporation
PURA	Public Utility Regulatory Act
RAMORT	Reasonable Annual Amortization Amount of a System Resiliency Plan-Related Regulatory Asset created pursuant to 16 TAC § 25.62
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SPS	Southwestern Public Service Company, a New Mexico corporation
SRP or Plan	System Resiliency Plan
Resiliency Rule	16 TAC § 25.62
TAC	Texas Administrative Code
TCRF	Transmission Cost Recovery Factor
TEF	Texas Energy Fund
Xcel Energy	Xcel Energy Inc.

LIST OF ATTACHMENTS

Attachment	**Description**
BAT-1	SPS SRP Sponsorship & Witness Testimony (*Filename:* SRP_Sponsorship_Testimony.docx)
BAT-2	Proposed Measure & Budget Chart (*Filename:* SRP_Measure_Budget.docx)
BAT-3	List of Prior Testimony (*Filename:* BAT_Prior_Test.xlsx)

DIRECT TESTIMONY
OF
BROOKE A. TRAMMELL

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Brooke A. Trammell. My business address is 790 South Buchanan Street, Amarillo, Texas 79101.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") and wholly owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is a registered holding company that owns several electric and natural gas utility operating companies, a regulated natural gas pipeline company, and three electric transmission companies.[1]

Q. By whom are you employed and in what position?

A. I am employed by SPS as Regional Vice President, Regulatory and Pricing.

Q. Please briefly outline your responsibilities as Regional Vice President, Regulatory and Pricing.

A. I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for SPS. I manage and oversee regulatory staff assigned to ratemaking, planning, policy, and resource transition matters. My duties include the design and implementation of SPS's regulatory strategy and

[1] The Xcel Energy Operating Companies are Northern States Power Company, a Minnesota corporation; Norther States Power Company, a Wisconsin corporation; Public Service Company of Colorado, a Colorado corporation; and SPS. Xcel Energy's natural gas pipeline company is WestGas InterState, Inc. Through a subsidiary, Xcel Energy Transmission Holding Company, LLC, Xcel Energy also owns three transmission-only operating companies.

programs as well as the direction and supervision of SPS's regulatory activities, including oversight of rate filings, administration of tariffs, rules and forms, and regulatory case direction and administration. I oversee the facilitation of the development of policy topics and advocacy to be included in regulatory filings, as well as the coordination of overall preparation of filed testimony, attachments, schedules, and workpapers to produce in accordance with applicable rules and procedures in the regulatory jurisdictions in which SPS operates.

Q. Have you testified before any regulatory authorities?

A. Yes. I have testified in a variety of cases before the Public Utility Commission of Texas ("Commission" or "PUCT") and the New Mexico Public Regulation Commission. In a prior role, I also testified on behalf of Public Service Company of Colorado ("PSCo") in numerous proceedings before the Colorado Public Utilities Commission on a variety of topics related to PSCo's electric, natural gas, and steam utility services.

A full list of the regulatory proceedings in which I have testified is provided as Attachment BAT-3 to my direct testimony.

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What is the purpose of your direct testimony?

A. I support SPS's request for approval of its System Resiliency Plan ("SRP" or "Plan") by initially providing an introductory discussion of the identified and evolving resiliency risks SPS's system faces and how, through the development of Wildfire Risk Maps, Wildfire Risk Tiers, robust third-party benefit-cost modeling, and a thoughtful project prioritization framework, SPS's SRP has been designed to

cost-effectively mitigate resiliency risks in the three-year plan period proposed. I also summarize SPS's development of its SRP, including third-party consultant engagement and modeling, measure identification, budget development, project execution planning, and metric creation. Included in this discussion is information related to grant funding that may be available to further support SPS's resiliency efforts. I also introduce the other SPS witnesses that sponsor proposed resiliency measures and/or portions of SPS's SRP, which is provided as Attachment A to SPS's Application.

To aid in the Commission's review of SPS's SRP, I present the total estimated cost of the SRP by measure, identify the timing of implementation of SRP measures, and discuss how SPS will track Distribution Cost Recovery Factor ("DCRF") eligible incremental costs associated with SRP measures and projects for inclusion in a regulatory asset, as allowed under 16 Tex. Admin. Code ("TAC") § 25.62 (the "Resiliency Rule"), as well as how SPS will fulfill reporting requirements outlined in the Resiliency Rule. Finally, I summarize the third-party costs that SPS has incurred in the development of its SRP and the preparation of this Application.

Q. Do you sponsor any sections of the SRP or attachments in this proceeding?

A. Yes. Each portion of SPS's proposed SRP is sponsored by me or co-sponsored by myself and other witnesses. Attachment BAT-1 to my direct testimony, which I also sponsor, provides a chart identifying sponsorship of the SRP as well as witness testimony topics. Additionally, I sponsor Attachment BAT-2, which summarizes

SPS's proposed measures and budgets, and Attachment BAT-3, which lists my prior testimony experience.

Q. Please summarize your testimony and recommendations.

A. SPS's proposed SRP is consistent with the Texas Legislature's intention in House Bill 2555 to prioritize resiliency of electric systems. The SRP is a product of (1) diligent assessment of the customer impacts of evolving weather-related and other operational resiliency risks on SPS's system; (2) utilization of third-party expertise to assess the wide array of resiliency measures, including through benefit-to-cost analyses and risk maps; and (3) development of a project prioritization framework that results in a robust initial SRP focused on addressing wildfire risk and improving resiliency. SPS's SRP contains five proposed measures: Distribution Overhead Hardening, Distribution System Protection Modernization, Communication Modernization, Operational Flexibility, and Wildfire Mitigation. 1898 & Co. conducted a benefit-cost analysis of the Distribution Overhead Hardening, Distribution System Protection Modernization, and Communication Modernization measures, and found that the combined benefit-cost ratio for these measures is 3.4, meaning these measures provide 3.4 times the economic benefit as they will cost to implement. The other measures were assessed either with the assistance of EDM International, Inc. ("EDM") or on a qualitative basis, and, as explained in the Plan and supporting witness testimony, are in the public interest.

Overall, SPS's SRP represents approximately $538.3 million of system investment that benefits customers by expanding upon SPS's current capabilities

and introducing valuable new programs that enhance system operations and security, improve public safety, and harden SPS's transmission and distribution networks. Consistent with the requirements of the Resiliency Rule, SPS proposes metrics for evaluating the effectiveness of the Plan in preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the relevant resiliency events.

The Resiliency Rule also requires separately tracking investment under the SRP. Relatedly, SPS is requesting to defer certain SRP costs through a regulatory asset. My direct testimony presents SPS's requested amortization period for the regulatory asset balance, describes the reconciliation of the SRP regulatory asset that will occur in SPS's next base rate case, and discusses SPS's plans for addressing SRP operations and maintenance ("O&M") costs through base rates and deferral mechanisms, as appropriate. Further, I discuss SPS's anticipated pursuit of state funding through the Texas Energy Fund ("TEF") as well as SPS's prior grant award and prospective application for funding through the U.S. Department of Energy's Grid Resilience and Innovative Partnerships ("GRIP") program. I then present the metrics that SPS proposes to use in the evaluation of its implementation of the SRP. Lastly, I describe SPS's engagement of third-party consultants and outside counsel in the development of SPS's SRP and this Application.

Accordingly, as set forth in its Application, SPS requests that the Commission: (1) find SPS's proposed SRP is in the public interest and compliant with 16 TAC § 25.62, and approve it; (2) authorize SPS to implement the SRP

through 2028 or at least three years after any approval of this SRP, whichever is later, unless SPS requests to amend the SRP with the amendment to take effect no later than three years from an approval of this SRP; (3) approve SPS's requested flexibility in implementation as described in the SRP and my testimony; (4) authorize SPS to establish a regulatory asset to capture distribution-related costs related to the implementation of the SRP; (5) authorize a twelve-month amortization period for the regulatory asset requested; (6) approve SPS's proposed metrics; and (7) grant all other relief the Commission deems necessary or appropriate.

III. SPS SYSTEM RESILIENCY PLAN & BENEFITS

A. Resiliency Events

Q. Has SPS identified the most impactful resiliency events on its system?

A. Yes. Due to its location in the Texas Panhandle and South Plains regions, SPS's system is susceptible to a variety of severe weather-related resiliency events, particularly wind and winter weather. In SPS's service territory, severe weather impacts can combine, increasing the impact and complexity of resiliency events. SPS worked with 1898 & Co., who used weather-based event data from the National Oceanic and Atmospheric Administration ("NOAA") and SPS's outage management system to understand the frequency and impacts of a range of weather-related resiliency events to SPS's Texas retail customers. As evidenced in the 1898 & Co. Report, the number of weather-related resiliency events and the profile of resiliency-event types vary significantly from year-to-year and location-to-location

across SPS's service area, demonstrating the challenge SPS faces in building and maintaining a resilient system.

Severe weather-related resiliency risks also present an elevated and evolving wildfire threat in SPS's service territory. As discussed in the direct testimony of SPS witness Anne Z. Sherwood, SPS's service area is particularly susceptible to wildfire due to geographic and climate attributes such as flammable vegetation and wind and drought weather patterns. Because of the significance and complexity of this wildfire risk, SPS engaged EDM to help it assess wildfire risk. EDM's expertise supports SPS's selection of the wildfire mitigation activities in the Plan.

As discussed in more detail by SPS witness Wendall A. Reimer, SPS faces elevated operational risk due to the lack of robust and contiguous public communication networks and associated equipment across its service territory. This risk is especially problematic given the rural nature and low customer density across SPS's expansive, 52,000 square mile service territory, 33,000 square miles of which are in Texas.

Q. How has SPS identified these key risks?

A. These key risks have been identified through third-party evaluation of NOAA-recorded weather-related resiliency events, historical SPS outage data, and wildfire risks, as well as the experience of SPS personnel.

First, with respect to severe weather-related resiliency events, SPS engaged 1898 & Co. to conduct various analyses, including an analysis of SPS's recorded

outages by Customer Minutes Interrupted ("CMI")[2] over the period of 2010 through 2023. This analysis found that approximately 65% of SPS's forced outages occurred during one of the weather-related resiliency events recorded by NOAA. This demonstrates that major weather events experienced in SPS's service territory significantly contribute to customer outages and highlights the need for resiliency investments to mitigate these impacts.

Second, SPS worked with EDM to produce wildfire risk map outputs that identify Hazardous Fire Areas ("HFAs"), Fire Tiers, and Operational Tiers, and develop a Wildfire Operations Map.[3] The establishment of these tools assisted SPS with the prioritization and implementation of wildfire risk mitigation measures and provides a regional snapshot of SPS's landscape and population wildfire risk categorization across its service territory, including those extending beyond its Texas service territory.

Third and finally, as discussed by Mr. Reimer in his direct testimony, communications with field devices on SPS's distribution system are limited to areas covered by public cellular networks. This severely restricts SPS's ability to deploy and take advantage of communications-enabled field devices. Public cellular networks are also more susceptible to cyber-attack and lack redundancy for operational technology communications to ensure that no single event can disrupt SPS's control over the system.

[2] *See* 1898 & Co. Report at Section 3.2.2.

[3] In general, the terms Wildfire Risk Map and Wildfire Operations Map are used interchangeably in direct testimony and in the SRP.

B. Measure Identification

Q. Has SPS's SRP been designed to mitigate these key risks?

A. Yes. SPS's SRP includes five measures, which consist of various programs and activities, designed to specifically address key severe weather-related resiliency events, wildfire risk, and the elevated operational effectiveness risk as a result of sparse public cellular network coverage (and cyber security risk related to reliance on public cellular networks). These five measures include:

1. Distribution Overhead Hardening – The activities in this measure include replacing and reinforcing distribution poles, replacing conductor, replacing line transformers, replacing open-wire secondary, mitigating long span-lengths, and, in heightened wildfire risk areas, wrapping poles with fire resistant coatings and replacing arrestors and transformer fuses with non-expulsion alternatives.
2. Distribution System Protection Modernization – The activities in this measure include installing sectionalizing reclosers, installing tie reclosers, installing communications equipment on existing reclosers, replacing substation relay panels, replacing substation breakers, installing lateral reclosers, and performing studies to optimize protection schemes with new equipment. Additionally, in areas of heightened wildfire risk, SPS will install fault current indicators and replace tap-level fuses with non-expulsion alternatives.

3. Communication Modernization – The activities in this measure include building out a private LTE network ("pLTE"), installing Fiber Optic cable, and adding remote terminal units ("RTUs") at select substations.

4. Operational Flexibility – The activities in this measure include procuring mobile substation equipment and installing additional switching devices on select transmission circuits.

5. Wildfire Mitigation – The activities in this measure include acquiring weather stations to enhance SPS's meteorological capabilities, adopting weather and fire science modeling, deploying Artificial Intelligence ("AI") cameras to more effectively detect wildfire threats, vegetation management to create defensible spaces around structures, wood substation conversions, and detailed visual inspections.

All of these measures have been designed to help SPS prevent, withstand, mitigate, or more promptly recover from resiliency events experienced on its system.

Q. How did SPS determine the five proposed measures were the most appropriate measures to propose in its SRP?

A. Ultimately, SPS selected the measures, programs, and activities presented in this SRP based on several objectives, including (1) mitigating the impacts of resiliency events with the greatest impacts on the SPS system and its customers, as determined by SPS's operational experience and third party analyses; (2) furthering SPS's long-

term resiliency objectives, including mitigating wildfire risk and modernizing system protection capabilities; (3) leveraging the expertise of third-party consultants, including the resilience and risk benefit-cost ratio ("BCR") calculated by 1898 & Co., which accounts for the historical performance of SPS's system during resiliency events; and (4) optimizing the overall size of the Plan, with consideration for the costs to customers and SPS's ability to execute on the full portfolio of proposed investments between 2025 and 2028. The measures and programs in the SRP will work in conjunction with existing programs to support the continued reliable service that SPS customers, the Commission, and the Texas Legislature have come to expect from SPS and ensure that SPS's system is resilient against a wide array of potential events.

SPS prioritized the five proposed measures as the most appropriate measures to mitigate the key severe weather-related, wildfire-related, and operational effectiveness resiliency risks identified through a two-step process. First, SPS personnel coordinated with 1898 & Co. and EDM to select and design a set of measures that would address the resiliency risks to the SPS system and advance SPS's long-term resiliency objectives. Second, SPS evaluated alternatives to each proposed measure. SPS witness Brianne R. Jole discusses the alternatives considered for the Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures, which she co-sponsors. Additionally, discussion of alternatives considered are included in the direct testimony of Mr. Reimer, who co-sponsors the Communication

Modernization measure, and Ms. Sherwood, who co-sponsors the Wildfire Mitigation measure.

Q. Why are the proposed measures reasonable and in the public interest?

A. 1898 & Co.'s calculated resilience and risk BCR is a robust and reliable measure to help understand the justification for resilience investment activities included in the Distribution Hardening, Distribution System Protection Modernization, and Communication Modernization measures,[4] and it provides confidence that SRP investments will provide benefits in excess of costs for customers. As discussed in the 1898 & Co. Report, the benefit-cost evaluation shows significant opportunities to improve system resiliency for customers, with each measure and program providing quantified customer benefits in excess of cost.

The Operational Flexibility measure includes industry-standard programs and activities that will result in improved customer outage frequency and duration. As discussed by SPS witness Ms. Jole in her direct testimony, the programs under this measure were selected over alternatives due to deployment time, reliability, and cost.

Finally, SPS engaged EDM as a consultant with expertise in utility wildfire mitigation practices to assist in its assessment and selection of programs to include in its Wildfire Mitigation measure. SPS witness Ryan Brockbank of EDM testifies

[4] Although the Communication Modernization measure does not itself create independent quantified benefits, it is necessary to fully realize the benefits of the Distribution System Protection Modernization measure and, when considered in conjunction with that measure, results in a BCR of 1.8. In the average 3.4 BCR for all measures evaluated by 1898 & Co., the Communication Modernization measure is assumed to be fully deployed in the Distribution System Protection Modernization measure.

that the Wildfire Mitigation measure are intended to be dynamic and evolving, consistent with leading-utility practices.

C. Budget Development

Q. Has SPS developed an estimated budget for each proposed measure?

A. Yes. SPS's SRP details the types of incremental capital investments and O&M expenses SPS plans to expend in the Plan period for programs that will enhance the resilience of SPS's system. Attachment BAT-2 to my direct testimony contains a chart that provides details of proposed SRP measure/program activities and corresponding budget estimates. Table BAT-1 below summarizes SPS's estimated budget by measure. These individual measure budgets are co-sponsored by Ms. Jole, Mr. Reimer, and Ms. Sherwood. I discuss funding and cost recovery associated with SPS's proposed measures in the next section of my testimony.

Table BAT-1: SPS's SRP Budget by Measure

Measure	Estimated Capital Spend ($)	Estimated O&M Spend ($)	Total Estimated Spend ($)
Distribution Overhead Hardening	253.0M	--	253.0M
Distribution System Protection Modernization	92.3M	--	92.3M
Communication Modernization	112.7M	--	112.7M
Operational Flexibility	43.7M	0.006M	43.7M
Wildfire Mitigation	19.8M	16.8M	36.6M
Total	521.5M	16.8M	538.3M

Q. Is SPS requesting flexibility in the implementation of its SRP?

A. Yes. As stated in the direct testimony of Mr. Meeks, SPS is requesting flexibility in the implementation of its SRP to allow SPS to make adjustments, as appropriate,

in response to changing conditions and industry developments. Such adjustments may include the deployment of proposed program activities within measures or the reallocation of budgeted expenses between approved measures. SPS's requested implementation flexibility will not change the total cost of the overall Plan as approved but will instead allow SPS to accommodate potential changes in conditions or technologies as they are encountered. SPS is also requesting flexibility in terms of its business operations, timing, and methods for implementing its SRP to allow SPS to adopt efficient practices discovered throughout this process.

IV. SRP COST RECOVERY AND ACCOUNTING

Q. What is the purpose of this section of your testimony?

A. In this section of my direct testimony, I discuss SPS's plans for recovery of SRP-related costs, including deferral of distribution invested capital to a regulatory asset, potential state and federal funding for resiliency measures, and SPS's request to defer costs associated with the preparation of this Application and adjudication of this proceeding into a regulatory asset for evaluation and recovery in a future base rate proceeding.

Q. Do the measures proposed in SPS's SRP result in distribution related costs only?

A. No. Certain measures proposed in SPS's SRP are applicable to SPS's transmission and general plant infrastructure. For example, increased inspections and defensible space parameters included in the Wildfire Mitigation measure are applicable to transmission circuits as well as distribution circuits. Additionally, the Operational

Flexibility measure includes transmission investments, and the Communication Modernization measure includes general plant investments. These measures are discussed in the direct testimonies of Ms. Sherwood, Ms. Jole, and Mr. Reimer.

Q. How does SPS plan to recover the costs of its SRP?

A. For transmission-related investments approved under the SRP, SPS currently intends to recover costs in a future Transmission Cost Recovery Factor ("TCRF") proceeding or base rate proceeding. With respect to distribution invested capital, as authorized under 16 TAC § 25.62(f), SPS intends to defer all DCRF-eligible capital costs and all distribution-related operation and maintenance expenses incurred under its approved SRP for recovery through a regulatory asset. SPS is not planning to request approval of a Resiliency Cost Recovery Rider.

A. <u>Distribution SRP Deferral</u>

Q. Does the Resiliency Rule specify which mechanism is to be used to recover the regulatory asset balance if approved resiliency-related costs are deferred?

A. Yes. If SPS defers certain resiliency-related distribution costs through a regulatory asset, and if SPS then files a DCRF application (before a base rate case), 16 TAC § 25.62(f)(2)(A) states that those deferred costs must be included for recovery in DCRF rates subject to the formula set forth in the Resiliency Rule at 16 TAC § 25.62(f)(2)(B).

Consistent with the Commission's definition of "distribution invested capital" prescribed in 16 TAC § 25.62(b), the resiliency-related distribution invested capital will reflect incremental invested capital placed into service and functionalized as distribution plant, distribution-related intangible plant, and

distribution-related communication equipment and networks properly recorded in FERC Uniform System of Accounts 303, 352, 353, 360 through 364, 391, and 397. The proposed Plan estimates incremental O&M expense associated with implementing certain resiliency measures, as shown in Table BAT-1. Additionally, depreciation and amortization expense, return on SPS's resiliency investments, income taxes, Texas Gross Margin Tax, and ad valorem taxes related to the resiliency-related distribution invested capital will be recorded and tracked as resiliency-related expenses.

Q. Which distribution costs will SPS include in its SRP regulatory asset?

A. The regulatory asset will include the accumulated distribution invested capital's associated depreciation and amortization expense, ad valorem taxes, carrying costs, and associated income and Texas Gross Margin tax. The regulatory asset will also include the deferred distribution-related O&M associated with the Commission-approved SRP, such as the distribution-related O&M associated with SPS's proposed Defensible Space Around Poles ("DSAP") program in the Wildfire Mitigation measure.

B. Accounting of SRP Costs

Q. How does SPS propose to account for the capital investment and incremental expenses attributable to implementing its SRP once approved?

A. As I explain in more detail in the following sections of my direct testimony, SPS proposes to use its accounting structures and workorder processes currently in place to account for all costs associated with its SRP to ensure that costs are directed to

the appropriate accounts. SPS will separately track investments and expenditures incurred under SPS's SRP from non-SRP activities.

Q. Does this mean that all SRP costs will be tracked separately from general system investment?

A. Yes. The costs of these expansions and accelerations that are approved by the Commission as SRP measures will be tracked and accounted for separate and apart from existing system investment programs.

Q. How will SPS account for the resiliency-related distribution invested capital under its SRP?

A. SPS will record the resiliency-related capital expenditures in a manner that will readily allow for identification, tracking, and reporting on a monthly basis. SPS will maintain records of resiliency-related investment in a manner that will allow the Commission to fully review the costs in SPS's next base rate case. Upon Commission approval of SPS's SRP, SPS will begin tracking investment in resiliency distribution capital through the use of appropriate FERC accounts, property unit records, SRP-identifiable project structures, and activity codes. An SRP project structure will be assigned to each resiliency-related capital project and will be unique to each resiliency measure and method as defined in the SRP. This tracking will provide for the reporting and reconciliation of the resiliency distribution plant that has been placed in service.

Q. How will SPS track and record retirements related to implementing its SRP?

A. As described in its Plan, SPS anticipates performing a number of capital replacements that will enhance system resiliency. When the new capital asset is installed, it will be necessary to remove and retire the replaced asset from service. With the exception of certain general plant assets, such as computer equipment recorded in FERC Account 391 and communication equipment recorded in FERC Account 397, the retirement will be recorded at the same time or shortly after the new asset is placed in service, and will be tracked in the same manner as the distribution investment using the appropriate FERC account, property unit record, and unique SRP project structure such that the retirement is reflected as resiliency-related. Identifying the retirement as resiliency-related will ensure that the appropriate amount of depreciation and amortization expense attributable to resiliency-related net invested capital is calculated and recorded. For certain general plant investments recorded in FERC Accounts 391 and 397, depreciation and retirements are based on a vintaged group methodology. Retirements for these capital assets are recognized at the end of the asset's approved depreciable life.

Q. How will SPS account for incremental SRP expenses separate from any existing resiliency-related programs or initiatives?

A. SPS will record resiliency-related incremental expenses in a manner that will readily allow for their identification, tracking, and reporting on a monthly basis. Upon approval of the SRP, SPS will begin tracking its incremental distribution-related expenses associated with the implementation of its SRP in the appropriate

FERC expense accounts with a unique SRP project structure that will categorize the expenses by resiliency measure and method as defined in the approved SRP. This tracking methodology will allow for the reporting and reconciliation of the resiliency-related incremental expenses. It will also support the deferral of distribution invested capital through a regulatory asset as allowed by the Resiliency Rule.

Q. How will SPS track and record O&M expenses related to its SRP?

A. As previously described, SPS will use the appropriate FERC expense accounts combined with a unique SRP project structure to record the incremental SRP O&M costs as the costs are incurred. In other words, each SRP project will be identified and individually tracked to ensure all costs are accounted for appropriately. This cost recording methodology will allow for the identification, tracking, and reporting of resiliency-related O&M expenses. Only incremental O&M expenses associated with the approved SRP measures and not already included in base rates will be identified as resiliency-related.

Q. How will SPS track and record depreciation and amortization expenses on resiliency-related assets?

A. As described earlier in my direct testimony, distribution invested capital will be separately identifiable through the use of appropriate FERC accounts, unique project structures, and activity codes. SPS will record depreciation and amortization expenses related to these specific assets monthly. Depreciation expense is calculated by taking the original cost of the asset less retirements and

then applying the applicable depreciation rate established in SPS's last base rate case, Docket No. 54634. The depreciation and amortization expenses will be recorded to the appropriate FERC expense account identifiable with a unique project structure as resiliency-related.

Q. How will SPS track and record ad valorem taxes for resiliency-related assets?

A. The appropriate amount of ad valorem taxes will be calculated by applying the factor derived from the ad valorem and net plant amounts from Docket No. 54634 baselines to the incremental resiliency-related net plant amounts that are not being recovered in base rates.

Q. How will SPS record carrying costs in the regulatory asset?

A. The Resiliency Rule specifically allows for the recovery of carrying costs associated with balance of unrecovered resiliency-related costs incurred for the implementation of an approved SRP and not otherwise included in rates. SPS will calculate monthly the amount of carrying costs based on SPS's weighted average cost of capital approved in the most recent base rate proceeding related to the balance of unrecovered distribution-related net rate base (plant in service and associated accumulated depreciation and accumulated deferred income taxes) as well as unrecovered balance of costs recorded through a regulatory asset.

Q. Please explain the carrying costs that will be included in the regulatory asset.

A. Carrying costs will be calculated on a monthly basis using SPS's weighted average cost of capital approved in the most recent base rate proceeding, 7.11%, and applied to the distribution-related unrecovered rate base (plant in service and associated

accumulated depreciation and accumulated deferred income taxes) as well as the balance of unrecovered resiliency-related costs booked through a regulatory asset.

Q. Please summarize how SPS proposes to utilize the resiliency-related regulatory asset for recording and recovering SRP-related costs.

A. As I have described throughout my testimony, SPS will record its resiliency-related costs in a manner such that the costs can be readily identified. Each month, the total amount of distribution-related O&M expense, depreciation and amortization expense, return on SPS's resiliency investments, income taxes, Texas Gross Margin tax, ad valorem taxes, and carrying costs applicable to implementing SPS's SRP will be recorded through a regulatory asset. SPS will seek recovery of its resiliency-related regulatory asset balance over a 12-month amortization period through its DCRF applications. All resiliency-related costs, including those approved for recovery in SPS's approved DCRF and TCRF applications, and amortization of the unrecovered regulatory asset balance for the respective period will be included in SPS's next base rate filing for review and inclusion in base rates.

Q. How does 16 TAC § 25.62 prescribe the recovery of the regulatory asset in a DCRF?

A. 16 TAC § 25.62(f)(2)(B) provides a formula that must be used when filing a DCRF that includes the amortization of the regulatory asset related to distribution spend associated with an approved SRP. While the formula starts out the same as the DCRF required in 16 TAC § 25.243(d)(1), the Resiliency Rule adds "RAMORT," where RAMORT is equal to a reasonable annual amortization amount of the SRP-

related regulatory asset. In addition, upon the Commission's approval of SPS's DCRF rates, the resiliency-related regulatory asset balance will be reduced at an annual rate by the value of RAMORT.

Q. What amortization period does SPS propose be applied to its SRP regulatory asset balance?

A. SPS proposes a 12-month amortization period be applied to its SRP regulatory asset balance in DCRF proceedings following SRP approval. By proposing approval of the 12-month amortization period in this proceeding, SPS intends to alleviate the pressures of time constraints that may be present in a future DCRF proceeding given the 60-day decision deadline for such a case.[5] In addition, PURA § 36.210(d), allows for the adjustment of a utility's DCRF no more than twice per year; thus, SPS will likely file two DCRFs on a semi-annual cadence as it deploys its approved SRP investments, which should provide gradual price impacts to bills for customers instead of requesting approval of a larger increase in a base rate application two or three years after the investments are made. A 12-month amortization period would also incur fewer carrying costs for customers. SPS's proposal is consistent with its commitment to keep customer bills as low as possible while making its system more resilient to meet their needs.

[5] *See* Senate Bill 1015 (became effective on June 18, 2023). This bill amended PURA § 36.210 and requires the Commission to issue a final order in a DCRF proceeding no later than 60 days after the DCRF application is filed, unless there is good cause to extend by 15 days.

C. Reconciliation

Q. Please explain the reconciliation requirement in 16 TAC § 25.62(f)(3).

A. In accordance with 16 TAC § 25.62(f)(3), all Commission-approved, SRP-related costs recovered through rates in SPS's approved DCRF or TCRF applications will be subject to review and reconciliation in SPS's first base rate proceeding that is filed after the effective dates of the related rates. As part of the reconciliation process in a base rate case, the Commission will determine if the resiliency-related costs were reasonably and prudently expended consistent with SPS's approved SRP. Therefore, it will be necessary for SPS to include sufficient details of the incurred SRP costs in its base rate case filing such that a comprehensive review can be completed. The detailed tracking and recording of SPS's SRP costs in its books and records will also be provided to support the reconciliation. As required by the Resiliency Rule, SPS will file an annual resiliency plan report by May 1 each year following the year the SRP is approved.

D. State and Federal Funding

Q. Does SPS intend to pursue any state funding to help address costs associated with resilience in its Texas service territory?

A. Yes. SPS intends to pursue state funding for resiliency investment through the TEF when the Commission's TEF rulemaking is finalized. The TEF is a Texas grant program under which non-ERCOT utilities can apply for funding for investments such as resiliency-related facility enhancements. If appropriate under the adopted rule, SPS intends to pursue TEF grant funds for portions of the Distribution

Overhead Hardening measure and Distribution System Protection Modernization measure activities.

Q. Has SPS previously pursued, or is SPS considering pursuing, any federal funding to help address the costs associated with resilience in its Texas service territory?

A. Yes. SPS will explore the possibility of including certain SRP-related components in an application for funding through the federal GRIP program in Spring 2025. As Ms. Sherwood discusses in her testimony, SPS, and the larger Xcel Energy organization, previously received federal funding for aspects of wildfire hardening activities through the GRIP program in 2023, but details are still being finalized. Xcel Energy will continue to evaluate whether it is appropriate to apply GRIP funds to SPS's SRP. Xcel Energy will also consider the inclusion of additional SPS resiliency projects in areas related to distribution, transmission, and/or wildfire in a 2025 GRIP application as that program's new cycle criteria becomes available for a 2025 application submission and competition.

E. Case Costs

Q. Will SPS seek approval of any costs incurred prior to the Commission's approval of the SRP?

A. Yes. SPS will request approval for costs associated with the preparation of this SRP Application. SPS will defer these costs by recording them in a regulatory asset and request recovery in SPS's next base rate proceeding after Commission approval of its SRP.

Q. Has SPS incurred contracting costs associated with data analytics used to prepare this SRP?

A. Yes. SPS engaged 1898 & Co. and EDM International Inc., both third-party consultants that assisted SPS in developing, applying, and understanding quantitative evaluation tools and evaluating wildfire risk. This allowed SPS to conduct a data-informed approach to preparing its SRP and prioritizing projects included in each measure.

Q. Please further explain the process by which SPS worked with 1898 & Co. to develop its SRP.

A. SPS engaged 1898 & Co. to help evaluate certain proposed resiliency projects. Specifically, 1898 & Co. provided outside data analysis of the costs and benefits of the Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures as they relate to system resiliency improvements. To facilitate its analysis, SPS provided 1898 & Co. with prior SPS reports, such as annual Storm Hardening Reports and comprehensive data sets related to SPS's distribution assets, historical outages, restoration costs, and other operations figures. SPS then arranged routine workshops with 1898 & Co. to discuss unique aspects of SPS's system as they relate to the SRP and resiliency in general. During these regular workshops, supplemental data was provided as new issues for analysis were uncovered.

To inform SPS's selection of proposed SRP activities, 1898 & Co. performed a benefit-to-cost ratio analysis for certain SRP measures. In conjunction

with the discussions during SPS's routine workshops with 1898 & Co., SPS strategically leveraged 1898 & Co.'s analysis to maximize the benefits of the resiliency investments proposed in the SRP. SPS examined 1898 & Co.'s BCR of various initial programs and measures to determine which investments would yield the highest system-resiliency benefit for SPS's customers. Additionally, 1898 & Co.'s analysis provided guidance as to the most efficient implementation plan for certain resiliency-based programs.

Q. Please further explain the process by which SPS worked with EDM International, Inc. to develop its SRP.

A. SPS engaged EDM to aid in the development of portions of the SRP pertaining to wildfire mitigation. Through collaboration with EDM, SPS assessed wildfire risk to its service territory and developed a Wildfire Risk Map with three distinct tiers for identification and prioritization of wildfire mitigation programs, as seen throughout SPS's SRP. EDM also provided its assessment, as a consulting firm specializing in wildfire mitigation, of SPS's SRP wildfire mitigation programs. The direct testimonies of Ms. Sherwood and Mr. Brockbank further detail the coordinated efforts between SPS and EDM in developing the SRP.

Q. Did SPS contract any outside legal counsel to support the development of this Application?

A. Yes. SPS engaged the assistance of three outside legal firms, Dorsey & Whitney, LLP, Vinson & Elkins LLP, and Wilkinson Barker Knauer, LLP, to support the development of SPS's SRP, Application, testimony, and supporting documentation.

These firms will continue their engagement throughout the pendency of this proceeding, and SPS will include costs incurred by these firms in the same regulatory asset as the deferred costs associated with 1898 & Co.'s and EDM's work.

V. ANNUAL REPORTING & PROPOSED METRICS

Q. Please explain the annual reporting requirements in 16 TAC § 25.62(g).

A. 16 TAC § 25.62(g) defines the annual reporting requirements for a Commission-approved SRP beginning the year after the plan is approved. Among other things, the annual report must include "the actual capital costs and operations and maintenance expenses incurred in the prior year attributable to each measure." SPS will identify actual resiliency-related costs incurred in sufficient detail to meet the Commission's annual reporting requirements.

Q. Please describe the metrics SPS proposes for its SRP measures in accordance with the requirements of 16 TAC § 25.62(c)(2)(C).

A. As required by 16 TAC § 25.62(c)(2)(C), SPS proposes metrics for evaluating the effectiveness of each SRP measure in preventing, withstanding, mitigating, or more promptly recovering from the risks associated with the identified resiliency event.

Subsection 4 of each measure description within Section IV, and Section V, of SPS's SRP discusses the metric(s) and criteria for evaluating the measure. SPS proposes the following metrics:

- **Underperforming Area Count**: This metric identifies the number of underperforming areas across SPS's Texas system as categorized by the

Resiliency Rule. "Underperforming Areas" include distribution feeders for which the System Average Interruption Duration Index ("SAIDI") or System Average Interruption Frequency Index ("SAIFI") exceeds the system average by more than 300% for two or more consecutive years.

- **Rolling 10-Year Average SAIDI**: This metric evaluates all measures except for the Wildfire Mitigation measure by calculating the average duration of all outage events over the last 10 years, normalized for customer counts. The calculation used for this metric is reproduced below.

$$Rolling\ 10\ Year\ Average\ SAIDI = \frac{\sum_{i-1}^{10} Total\ SAIDI_i}{10}$$

- **Storm Restoration Duration**: This metric evaluates system improvement from all measures except for Wildfire Mitigation. The metric uses the formula, below, to calculate an average storm restoration duration for Major Event Days with more than 2.5 beta, as defined by IEEE 1366, a standard developed by the Institute of Electrical and Electronics Engineers ("IEEE"). Each year, a new average restoration duration will be calculated and compared with the average durations from the previous three years.

$$Storm\ Restoration\ Duration = \frac{\sum_{i=1}^{n}(Restoration\ Duration)_i}{Total\ Number\ of\ Major\ Event\ Days}$$

- **Average Hardened Protection Zone ("AHPZ") CI vs Average Protection Zone ("APZ") CI Comparison by County (Hardened Only)**: This metric compares hardened protection zones with non-hardened protection zones to show the effectiveness of hardening measures using the calculations reproduced below.

$$AHPZ\ CI = \frac{\sum_{i=1}^{n} Total\ CI_i}{Hardened\ Protection\ Zone\ Miles}$$

$$APZ\ CI = \frac{\sum_{i=1}^{n} Total\ CI_i}{Non\ Hardened\ Protection\ Zone\ Miles}$$

- **AHPZ CI Percentage Improvement**: This metric uses the calculation reproduced below to estimate the performance improvement between non-hardened protection zones and hardened protection zones. This metric includes all interruptions.

$$AHPZ\ CI\ \%\ Improvement = \frac{AHPZ\ CI\ (Hardened) - APZ\ CI(Non\ Hardened)}{APZ\ CI\ (Non\ Hardened)}$$

- **RAN Tower Completion**: This metric will track and report cellular tower construction completion, testing, and in-servicing as compared to the SRP to objectively measure SPS's implementation of the Communication Modernization measure and related activities.
- **End Device Connectivity**: This metric will report connectivity of end devices to pLTE cellular towers, including acceptance from the business unit on end-to-end testing validation in accordance with the Plan to provide data to evaluate whether the added connectivity is reducing the impacts of

resiliency events for SPS customers, which is the ultimate goal of this measure.

- **Units Completed in DSAP**: This metric calculates and reports the number of units identified and completed in Tiers 2 and 3 for DSAP compared to the Plan.
- **Transmission Inspections**: This metric involves the detailed inspections executed in Tiers 2 and 3 wildfire areas, with associated number of emergency and high-priority defects identified and remediated to demonstrate program progress and ensure the durations of defects on the system are limited.

The table below identifies the metric(s) that will be used to evaluate the effectiveness of each proposed SRP measure.

Table BAT-2: SPS's SRP Proposed Metrics

Metric	Distribution Overhead Hardening	Distribution System Protection Modernization	Communication Modernization	Operational Flexibility	Wildfire Mitigation
Underperforming Area Count	X	X	X		
Rolling 10-Year Average SAIDI	X	X	X	X	
Storm Restoration Duration	X	X	X		
Average Hardened Protection Zone (AHPZ) CI vs Average Protection Zone (APZ) CI Comparison by County (Hardened Only)	X				
AHPZ CI Percentage Improvement	X				
RAN Tower Completion			X		
End Device Connectivity			X		
Units Completed in DSAP					X
Transmission Inspections					X

Q. How often will SPS review the results of applying the proposed metrics to the measures proposed in its SRP?

A. SPS will apply its above-described metrics to the proposed SRP measures as shown in Table BAT-2 and review the results annually, with the exception of the Rolling 10-Year Average SAIDI metric and the Storm Restoration Duration metric. These two metrics will require the impact of resiliency measures to accumulate over the

first several years of the investment before they can be used to evaluate effectiveness.

VI. CONCLUSION

Q. Please summarize the relief requested by SPS in this proceeding.

A. SPS respectfully requests that the Commission: (1) find SPS's proposed SRP is in the public interest and compliant with 16 TAC § 25.62, and approve it; (2) authorize SPS to implement the SRP through 2028 or at least three years after any approval of this SRP, whichever is later, unless SPS requests to amend the SRP with the amendment to take effect no later than three years from an approval of this SRP; (3) approve SPS's requested flexibility in implementation as described in the SRP and my testimony; (4) authorize SPS to establish a regulatory asset to capture distribution-related costs related to the implementation of the SRP; (5) authorize a twelve-month amortization period for the regulatory asset requested; (6) approve SPS's proposed metrics; and (7) grant all other relief the Commission deems necessary or appropriate.

Q. Does this conclude your direct testimony?

A. Yes.

AFFIDAVIT

STATE OF TEXAS)
)
COUNTY OF POTTER)

BROOKE A. TRAMMELL, first being sworn on her oath, states:

I am the witness identified in the preceding testimony. I am over 18 years of age, of sound mind, and am capable of making this affidavit. I have read the testimony and the accompanying attachments and am familiar with the contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

BROOKE A. TRAMMELL

Subscribed and sworn to before me this 27th day of December 2024 by BROOKE A. TRAMMELL.

PAUL JEFFREY RAVERFIELD
Notary Public, State of Texas
Comm. Expires 10-21-2026
Notary ID 134028201

Notary Public, State of Texas

My Commission Expires: 10-21-2026

SPS SRP Filing Package Direct Testimony & Sponsorship

Witness	Area of Testimony	Bates Page #	Sponsored SRP Section(s)
Adrian J. Rodriguez SPS President	Introduces and supports SPS's SRP; provides overview of SPS's service territory, customer makeup, and resiliency events that pose a risk to the SPS System; discusses SPS's approach to resiliency and the actions it is currently taking to advance resiliency of its system.	311	None
Brooke A. Trammell SPS Regional Vice President, Regulatory and Pricing	Supports SPS's SRP, including all measures and programs therein; presents budgeting for the SRP; discusses SRP cost recovery; explains and supports SPS's proposed tracking and accounting plan for SRP-related costs; discusses state and federal resiliency-related funding opportunities; describes SPS's proposed SRP evaluation metrics.	328	All Sections
Casey S. Meeks SPS Regional Vice President, Distribution Operations	Describes SPS's distribution system and specific factors connected to resiliency issues; explains the impact resiliency events have on SPS distribution system operations; discusses SPS's SRP implementation strategy.	372	Section III.C Section V
Brianne R. Jole Xcel Energy Services Inc. Manager, System Planning and Strategy, Distribution Integrated Planning	Describes SPS's coordination with 1898 & Co. in developing the SRP; introduces SRP measures; discusses SPS's current and ongoing approach to resilience and prioritization in SRP program selection; describes and supports the Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility SRP measures.	400	Section III Section IV.A Section IV.B Section IV.D
Wendall A. Reimer Xcel Energy Services Inc. Director II (IT) - Application Delivery, Technology Services	Supports the Communication Modernization measure; discusses migration of SPS's OT communications to a private LTE network; explains the resiliency benefits associated with the proposed	445	Section II.C Section IV.C Section V

Witness	Area of Testimony	Bates Page #	Sponsored SRP Section(s)
	private communications infrastructure.		
Jason D. De Stigter 1898 & Co. Director, Utility Investment Planning	Introduces, summarizes, incorporates, and supports the Resilience Investment Study performed by 1898 & Co. for SRP development (the "1898 & Co. Report"); explains the methodology used by 1898 & Co. in its evaluation.	470	Section II.A 1898 & Co. Report (SRP Attachment A)
Anne Z. Sherwood Xcel Energy Services Inc. Area Vice President, Wildfire Mitigation: Regulatory and Policy	Supports and describes the Wildfire Mitigation measure; discusses wildfire risks within SPS's service area and SPS's current wildfire mitigation and risk assessment activities; describes SPS's engagement of outside expert consultants to advance wildfire-related resiliency.	520	Section IV.E Section V
Ryan Brockbank EDM International, Inc. Principal	Discusses and supports the Wildfire Mitigation measure; provides an explanation of wildfire risk mapping and SPS's Wildfire Operations Map.	542	Section II.B

Measure	Program	Resiliency Risk Event	Activities	Justification	Estimated SRP Spend ($)
Distribution Overhead Hardening	Distribution Circuit Hardening Rebuild	Wind, Flood, Tornado, Winter, Heat, Cold, and Wildfire	1) Pole Replacements 2)Conductor and Open-Wire Secondary Replacements 3) Line Transformer Replacements 4) Pole wraps 5) Pole Trussing 6) Wildfire Transmission Ignition Mitigation Fuse Replacements 7) Wildfire Arrestor Replacements	Plan Section IV.A 1898 & Co. Report Jason D. De Stigter Direct Testimony Brianne R. Jole Direct Testimony Casey S. Meeks Direct Testimony	Capital: 253.0M O&M: -- Total: 253.0M
Distribution System Protection Modernization	Mainline Automated Reclosing Deployment	Wind, Flood, Tornado, Winter, Heat, Cold, and Wildfire	1) Sectionalizing Recloser Installation 2) Tie Recloser Installation 3) Existing Recloser Communication Installation 4) Substation Relay Panel Replacements 5) Substation Breaker Replacements 6) Fault Indicator Installation 7) Enhanced Powerline Safety Setting Feeder Upgrades 8) Wildfire Fuse Replacements	Plan Section IV.B 1898 & Co. Report Jason D. De Stigter Direct Testimony Brianne R. Jole Direct Testimony Anne Z. Sherwood Direct Testimony Wendall A. Reimer Direct Testimony	Capital: 90.1M O&M: -- Total: 90.1M
	Lateral Reclosing Deployment Lateral Reclosing Deployment	Wind, Flood, Tornado, Winter, Heat, and Cold	1) Installation of Lateral Reclosers	Plan Section IV.B 1898 & Co. Report Jason D. De Stigter Direct Testimony Brianne R. Jole Direct Testimony Wendall A. Reimer Direct Testimony	Capital: 2.1M O&M: -- Total: 2.1M
Communication Modernization	Communication Modernization	Wind, Flood, Tornado, Winter, Heat, Cold, Wildfire, and Cybersecurity	1) Private LTE Network Buildout Private Fiber Optic and RTU Installation	Plan Section IV.C 1898 & Co. Report Jason D. De Stigter Direct Testimony Brianne R. Jole Direct Testimony Wendall A. Reimer Direct Testimony	Capital: 112.7M O&M: -- Total: 112.7M

Measure	Program	Resiliency Risk Event	Activities	Justification	Estimated SRP Spend ($)
Operational Flexibility	Mobile Substation Equipment Procurement	Wind, Flood, Tornado, Winter, Heat, and Cold	1) Equipment Procurement	Plan Section IV.D Brianne R. Jole Direct Testimony Casey S. Meeks Direct Testimony	Capital: 30.8M O&M: 0.006M* Total: 30.8M *Calculated based on a $36/month charge
	Installation of Transmission Switches	Wind, Flood, Tornado, Winter, Heat, and Cold	1) Installation of Transmission Switches	Plan Section IV.D Brianne R. Jole Direct Testimony	Capital: 12.9M O&M: -- Total: 12.9M
Wildfire Mitigation	Situational Awareness	Wildfire	1) Enhanced Meteorology Capabilities 2) Weather and Fire Science Modeling 3) Artificial Intelligence Cameras 4) Wildfire Tier Maps	Plan Section IV.E Anne Z. Sherwood Direct Testimony Ryan Brockbank Direct Testimony	Capital: 17.8M O&M: 2.3M Total: 20.1M
	Operational Mitigation	Wildfire	1) Defensible Space Around Poles (DSAP) 2) Wood Substation Conversion 3)Transmission Wildfire Annual Visual Inspection	Plan Section IV.E Anne Z. Sherwood Direct Testimony Ryan Brockbank Direct Testimony	Capital: 2.0M O&M: 14.5M Total: 16.5M

List of Prior Testimony

No.	Case Description	Regulatory Agency	Company
NMPRC Case No. 24-00270-UT	*In The Matter Of Southwestern Public Service Company's Application For Approval Of: Continued Use Of Its Fuel And Purchased Power Cost Adjustment Clause ("FPPCAC") Using A Monthly Adjustment Factor Under NMPRC Rule 550, And For Implementation Of Certain Matters Through The FPPCAC .*	New Mexico Public Regulation Commission	SPS
NMPRC Case No. 24-00114-UT	*In the Matter of Southwestern Public Service Company's Application Requesting a Determination on Location Approval of Two Solar Facilities, a Battery Energy Storage System, and a 230 kV Transmission Generation Tie Line in Lea County and Other Associated Relief*	New Mexico Public Regulation Commission	SPS
PUCT Docket No. 55973	*Application of Southwestern Public Service Company for Authority to Reconcile Fuel and Purchased Power Costs for the Period July 1, 2021 Through June 30, 2023*	Public Utility Commission of Texas	SPS
NMPRC Case No. 23-00384-UT	*In the Matter of Southwestern Public Service Company's Application Requesting Approval of Two Long Term Purchased Power Agreements*	New Mexico Public Regulation Commission	SPS
NMPRC Case No. 23-00271-UT	*In the Matter of Southwestern Public Service Company's Application for Authorization of Large Customer Renewable*Connect Program and Tariff and Other Associated Relief*	New Mexico Public Regulation Commission	SPS
PUCT Docket No. 55255	*Application of Southwestern Public Service Company to Amend Its Certificate of Convenience and Necessity to Construct Generation Facilities in Lamb County, Texas and Lea County, New Mexico; for Good-Cause Exceptions; and for Related Relief*	Public Utility Commission of Texas	SPS
NMPRC Case No. 23-00252-UT	*In the Matter of Southwestern Public Service Company's Application Requesting: (1) Issuance of a Certificate of Public Convenience and Necessity to Construct and Operate Solar Generation and Battery Storage Projects and Associated Facilities; (2) Authorization of Related Ratemaking Principles Including Accrual of an Allowance for Funds Used During Construction; (3) Authorization to Abandon the Cunningham Unit 2 Generating Facility; and (4) Other Associated Relief*	New Mexico Public Regulation Commission	SPS
PUCT Docket No. 54952	*Application of Southwestern Public Service Company to Revise its Fuel Factor Formula; Interim Approval; and for Related Relief*	Public Utility Commission of Texas	SPS
PUCT Docket No. 54634	*Application of Southwestern Public Service Company for Authority to Change Rates*	Public Utility Commission of Texas	SPS
NMPRC Case No. 22-00286-UT	*In the Matter of Southwestern Public Service Company's Application for: (1) Revision of Its Retail Rates Under Advice Notice No. 312; (2) Authority to Abandon the Plant X Unit 1, Plant X Unit 2, and Cunningham Unit 1 Generation Stations and Amend the Abandonment Date of the Tolk Generating Station; and (3) Other Associated Relief*	New Mexico Public Regulation Commission	SPS
PUCT Docket No. 53529	*Application of the City of Lubbock, Acting By and Through Lubbock Power & Light, for Authority to Connect the Remaining Portion of its Load with the Electric Reliability Council of Texas and for Approval of Settlement Agreement*	Public Utility Commission of Texas	SPS
PUCT Docket No. 53034	*Application of Southwestern Public Service Company to Reconcile Fuel and Purchased Power Costs for the Period July 1, 2018 through June 30, 2021*	Public Utility Commission of Texas	SPS
NMPRC Case No. 22-00178-UT	*In the Matter of Southwestern Public Service Company's Application for Authorization to Implement Grid Modernization Components that Include Advanced Metering Infrastructure and Recover the Associated Costs through a Rider, Issuance of Related Accounting Orders, and Other Associated Relief*	New Mexico Public Regulation Commission	SPS

No.	Case Description	Regulatory Agency	Company
CPUC Proceeding No. 22AL-0046G	*In the Matter of Advice No. 993 - Gas of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 6 - Gas Tariff to Increase Jurisdictional Base Rate Revenues, Implement New Base Rates for All Gas Rate Schedules, and Make Other Proposed Tariff Changes Effective February 24, 2022*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21A-0298E	*In the Matter of the Application of Public Service Company of Colorado for Certificates of Public Convenience and Necessity for Interconnection Facilities and Network Upgrades Associated with the Colorado Energy Plan Portfolio*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21A-0472G	*In the Matter of the Application of Public Service Company of Colorado for a Certificate of Public Convenience and Necessity for the West Metro Gas Project*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21A-0071G	*In the Matter of the Verified Application of Public Service Company of Colorado for Approval to Extend the Company's Pipeline System Integrity Adjustment ("PSIA") Rider for Certain Projects Through 2024, with Subsequent Wind-Down of the Rider*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21A-0370E	*In the Matter of the Application of Public Service Company of Colorado for an Order Approving Expenses Incurred for the Period January 2020 through December 2020 that are Recovered Through the Electric Commodity Adjustment and Approving of the Calculation of 2020 Short Term Sales Margins*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21AL-0317E	*In the Matter of Advice Letter No. 1857 - Electric filed by Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 - Electric Tariff to Revise Jurisdictional Base Rate Revenues, Implement New Base Rates for All Electric Rate Schedules, and Make Other Proposed Tariff Changes to Become Effective August 2, 2021*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21A-0279E	*In the Matter of the Application of Public Service Company of Colorado for Approval to Amend the Certificate of Public Convenience and Necessity for its Advanced Grid Intelligence and Security (AGIS) Initiative*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21A-0203ST	*In the Matter of The Application of Public Service Company of Colorado for Recovery of Costs Associated with the February 2021 Extreme Weather Event for its Steam Utility*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21A-0192EG	*In the Matter of the Application of Public Service Company of Colorado for Recovery of Costs Associated with the February 2021 Extreme Weather Event for its Electric and Gas Utilities*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21A-0141E	*In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 21A-0096E	*In the Matter of the Application of Public Service Company of Colorado for a Certificate of Public Convenience and Necessity for Colorado's Power Pathway 345 kV Transmission Project and Associated Findings Regarding Noise and Magnetic Field Reasonableness*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 20AL-0432E	*In the Matter of Advice No. 1835 - Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 - Electric Tariff to Eliminate the Currently Effective General Rate Schedule Adjustments to Place into Effect Revised Base Rates and Other Phase II Tariff Proposals to Become Effective November 19, 2020*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 20A-0082E	*In the Matter of the Application of Public Service Company of Colorado for a Certificate of Public Convenience and Necessity for the High Point Substation Project*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 20A-0327E	*In the Matter of the Application of Public Service Company of Colorado for an Order Approving Expenses Incurred for the Period January 2019 through December 2019 that are Recovered through the Electric Commodity Adjustment and Approving of the Calculation of 2019 Short Term Sales Margins*	Colorado Public Utilities Commission	PSCo

No.	Case Description	Regulatory Agency	Company
CPUC Proceeding Nos. 19A-0728E 20A-0063E (consolidated)	*In the Matter of the Application of Public Service Company of Colorado for a Certificate of Public Convenience and Necessity for the Voltage Control Facilities Associated with the Colorado Energy Plan* *In the Matter of the Application of Public Service Company of Colorado for a Certificate of Public Convenience and Necessity for the Greenwood to Denver Terminal 230 kV Transmission Project Associated with the Colorado Energy Plan, Associated Findings of Noise and Magnetic Field Reasonableness, and Uprate Projects*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 19A-0225E	*In the Matter of the Application of Public Service Company of Colorado for Approval of its Community Resiliency Initiative Pursuant to § 40-2-203(4), C.R.S.*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 20AL-0049G	*In the Matter of Advice No. 961 - Gas of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 6 - Gas Tariff to Increase Jurisdictional Base Rate Revenues, Implement New Base Rates for All Gas Rate Schedules, and Make Other Proposed Tariff Changes Effective March 7, 2020*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 20A-0300E	*In the Matter of the Application of Public Service Company of Colorado for Approval of Wildfire Mitigation Plan and Wildfire Protection Rider*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 19A-0425E	*In the Matter of the Application of Public Service Company of Colorado for an Order Approving Expenses Incurred for the Period January 2018 Through December 2018 that are Recovered Through the Electric Commodity Adjustment and Approving the Calculation of 2018 Short Term Sales Margins*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 19AL-0687E	*In the Matter of Advice Letter No. 1814 - Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 - Electric Tariff to Reflect a Modified Schedule RE-TOU and Related Tariff Changes to be Effective on Thirty-Days' Notice*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 19AL-0309G	*In the Matter of Advice No. 949 - Gas Filed by Public Service Company of Colorado to Revise its Colorado P.U.C. No. 6 - Gas Tariff to Reflect Revised Rates and Rate Schedules, Revise its Transportation Tariff, and Make Other Proposed Tariff Changes to be Effective on Thirty-Days' Notice*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 19AL-0268E	*In the Matter of Advice No. 1797 - Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 - Electric Tariff to Implement Rate Changes Effective on Thirty-days' Notice*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 18A-0905E	*In the Matter of the Application of Public Service Company of Colorado for Approval of the 500 MW Cheyenne Ridge Wind Project, a Certificate of Public Convenience and Necessity for the Cheyenne Ridge Wind Farm, and a Certificate of Public Convenience and Necessity for the 345 kV Generation Tie Line and Associated Findings of Notice and Magnetic Field Reasonableness*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 17AL-0363G	*In the Matter of Advice Letter No. 912 - Gas Filed by Public Service Company of Colorado to Revise its Colorado P.U.C. No. 6-Gas Tariff to Implement a General Rate Schedule Adjustment and Other Rate Changes Effective on 30-Days Notice*	Colorado Public Utilities Commission	PSCo
CPUC Proceeding No. 18M-0401E	*In the Matter of the Commission's Consideration of the Revised Stipulation and Settlement Agreement Regarding the Incorporation of the Impacts of the Tax Cut and Jobs Act of 2017 Into the Rates of Public Service Company of Colorado for Electric Service*	Colorado Public Utilities Commission	PSCo
PUCT Docket No. 45560	*Application of Southwestern Public Service Company for Authority to Refund Remaining Gain-on-Sale Amounts Associated with Docket Nos. 41430 and 44671*	Public Utility Commission of Texas	SPS

List of Prior Testimony

No.	Case Description	Regulatory Agency	Company
PUCT Docket No. 44498	*Review of Rate Case Expenses Incurred by Southwestern Public Service Company and Municipalities in Docket No. 43695*	Public Utility Commission of Texas	SPS
PUCT Docket No. 42004	*Application of Southwestern Public Service Company for Authority to Change Rates and Reconcile Fuel and Purchased Power Costs for the Period of July 1, 2012 through June 30, 2013*	Public Utility Commission of Texas	SPS
PUCT Docket No. 39362	*Texas-New Mexico Power Company Request for Approval to Adjust the Energy Efficiency Cost Recovery Factor (EECRF) and Related Relief*	Public Utility Commission of Texas	TNMP
PUCT Docket No. 39362	*Texas-New Mexico Power Company Request for Approval to Adjust the Energy Efficiency Cost Recovery Factor (EECRF)*	Public Utility Commission of Texas	TNMP
CPUC Proceeding No. 20A-0375E	*In the Matter of the Application of Public Service Company of Colorado for Approval of the PPA Termination Agreement with KEPCO Solar of Alamosa, LLC and Authority to Establish a Regulatory Asset and Recover Costs Associated with the PPA Termination Agreement through the Electric Commodity Adjustment*	Colorado Public Utilities Commission	PSCo

DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF A SYSTEM RESILIENCY PLAN	**§ § § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY
of
CASEY S. MEEKS

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

(Filename: MeeksDirect.docx; *Total Pages:* 28)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
1898 & Co. Report	SPS System Resiliency Investment Study
Commission or PUCT	Public Utility Commission of Texas
C&I	Commercial and Industrial Customers
DSAP	Defensible Space Around Poles
EPC	Engineering, Procurement, and Construction
FPIP	Feeder Performance Improvement Program
NESC	National Electric Safety Code
PURA	Public Utility Regulatory Act
SPS	Southwestern Public Service Company
SRP	System Resiliency Plan
Wood Pole Program	Wood Pole Inspection and Treatment Program
Xcel Energy	Xcel Energy Inc.

LIST OF ATTACHMENTS

Attachment	Description
CSM-1	SRP Estimated Spend by Implementation Year (*Filename*: Attachment CSM-1.xlsx)

DIRECT TESTIMONY
OF
CASEY S. MEEKS

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Casey S. Meeks. My business address is 4201 Frankford Avenue, Lubbock, Texas 79407.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS"). SPS is a wholly-owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by SPS as the Regional Vice President, Distribution Operations.

Q. Please briefly outline your responsibilities as Regional Vice President, Distribution Operations.

A. My responsibilities include leading the SPS Distribution Operations organization, which includes electric distribution design and layout, construction, operations, maintenance, and emergency repair activities for SPS's distribution system. As such, I provide the central point of contact for all issues regarding SPS Distribution Operations. I am also responsible for deploying Distribution Operations personnel in an effective and efficient manner, with an emphasis on safety, reliability, customer satisfaction, and compliance.

Q. Please describe the responsibilities of SPS's Distribution Operations organization.

A. Distribution Operations focuses on reliability, safety, customer service, operational efficiency, and the fiscal oversight necessary to construct, operate, and maintain SPS's electric distribution system in Texas and New Mexico. Distribution Operations has the primary responsibility for siting and land rights, design, work coordination, construction, distribution control center operations, and contract and utility services.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Mechanical Engineering from Texas Tech University in Lubbock, Texas, in December of 2007.

Q. Please describe your professional experience.

A. I was hired by SPS in Hobbs, New Mexico, as a distribution engineer in January of 2008. As a distribution engineer, I was responsible for the design, procurement of materials, and management of projects primarily related to the extension of electrical service to new customers in and around the Hobbs, New Mexico area. In 2011, I took a position as Manager of Distribution Design for the Texas South (with responsibility for the portion of SPS's service territory in the southern part of the Texas Panhandle and counties surrounding Lubbock) and New Mexico regions (with responsibility for all of the portion of SPS's service territory in New Mexico) of SPS, leading a team of designers and engineers responsible for the design of projects that safely serve new electric customers and provide for distribution system reliability. In 2013, I was promoted to Director of Distribution Engineering, Construction and Maintenance for the Texas South division of SPS. In October of

2018, I was promoted to Senior Director of Distribution Operations for SPS and have been in my current position as Regional Vice President since July 2024. I continue to devote my time to operating SPS's Texas and New Mexico electric distribution systems.

Q. Do you hold any professional licenses?

A. Yes. I am a licensed Professional Engineer in Texas and New Mexico.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the American Society of Mechanical Engineers.

Q. Have you testified or submitted pre-filed written testimony in any prior proceedings?

A. Yes. I submitted pre-filed written testimony in Public Utility Commission of Texas ("Commission") Docket Nos. 49831, 51802, 54634, 56595, and 57135. I have also submitted pre-filed written testimony to the New Mexico Public Regulation Commission.

II. ASSIGNMENT AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support SPS's application for approval of its System Resiliency Plan ("SRP") by discussing operational factors unique to SPS's resiliency of its distribution system and the implementation of SRP projects, if approved. Specifically, I (1) provide an overview of the SPS distribution system and how resiliency events impact SPS distribution system operations, particularly given SPS's unique system challenges; (2) describe how SPS will implement projects proposed within the SRP, including contracting, supply chain, and timeline

issues; and (3) discuss metrics SPS will use for evaluating the Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures, which are described in more detail in the SRP.

Q. What has been your role in the development of the SRP?

A. In my role with Distribution Operations, I participated in the collection of information about SPS's distribution system and providing it to the outside consulting company engaged by SPS in this filing: 1898 & Co. The 1898 & Co. SPS System Resiliency Investment Study ("1898 & Co. Report"), which is provided as Attachment A to the SRP, addresses the specific data 1898 & Co. reviewed and relied upon in conducting its cost-benefit analysis of the measures in the SRP. I also met regularly with 1898 & Co. as they prepared their model and provided input to them and to the SPS internal team developing the SRP. I was also involved in analyzing and planning how SPS will implement the programs proposed in the SRP.

Q. What is your anticipated role in implementing the SRP if it is approved?

A. Given my responsibilities associated with siting and land rights, design, work coordination, construction, distribution control center, and contract and utility services for projects affecting SPS's distribution system, I anticipate being involved in SRP implementation activities.

Q. Please summarize your testimony and recommendations.

A. In my testimony, I (1) provide an overview of the SPS distribution system, SPS's existing resiliency programs, and the resiliency events that impact the SPS system; (2) describe how SPS will implement projects proposed within the SRP, including

by addressing contracting, supply chain, and timeline issues, and stating SPS's request for flexibility in implementation; and (3) identify metrics SPS will use for evaluating the measures, which are described in more detail in the SRP.

III. OVERVIEW OF THE SPS DISTRIBUTION SYSTEM

Q. What is the purpose of this section of your testimony?

A. The purpose of this section of my direct testimony is to provide an overview of SPS. In particular, I discuss the service area, distribution system characteristics, and distribution organization.

Q. Please describe the SPS distribution system.

A. SPS's service territory is generally marked by low customer density. The service area also contains large open areas with lengthy overhead spans. SPS owns, operates, and maintains approximately 16,500 circuit miles of distribution lines. The SPS distribution system consists of 93% overhead lines and 7% underground lines. In Texas, SPS has approximately 10,641 overhead circuit primary miles of distribution lines, nearly 266,000 poles, more than 360 feeders, and over 267,000 points of delivery. Comprehensive information regarding the SPS distribution system was provided to 1898 & Co. and is reflected in the SRP and the 1898 & Co. analysis.

Q. How does the low customer density of SPS's system affect resiliency planning?

A. Given that many of SPS customers reside or are located in rural settings, SPS's lines must cross long distances to reach relatively small population centers. As a result, the amount spent to upgrade equipment, sprawling wire, and volume of

structures is necessarily high relative to the number of customers who are affected by the upgrades.

Q. Is there anything notable about SPS's customer mix?

A. Yes. SPS's commercial and industrial customers ("C&I") make up only 19% of its total customers, but they account for 65% of total sales. That proportion of C&I load is uncommon among utilities.

Q. How do the rural nature of the service area and customer density affect SPS's system?

A. As described above, SPS has low customer density generally and especially among residential customers, some of whom reside in relatively isolated areas. As a practical matter, the number and density of SPS's customers means that SPS must invest more dollars per customer in the improvements needed to maintain the system and to ensure prompt restoration of service in the event of outages.

Q. Please describe how the resiliency events in SPS's service area impact system performance.

A. Located in the Texas Panhandle and South Plains region, SPS's system is susceptible to winter weather and winter storms (particularly icing), thunderstorms, tornadoes, and high winds, among other weather event categories. A complete list of weather resiliency events, with definitions, is provided in the 1898 & Co. Report. Drought, heat, and high winds also have the effect of increasing the risk of wildfire ignition.

These weather events are damaging when they occur as stand-alone weather events, but they also tend to occur in tandem, resulting in more severe and

prolonged resiliency events. High winds have a multiplying effect on both heat and cold weather events. For example, in the winter, freezing rain often leaves ice on SPS's lines. While the weight of the ice alone can cause problems, more damage occurs when high winds gallop the ice-laden lines. Mr. De Stigter's testimony and the 1898 & Co. Report provide specific data regarding the frequency of these and other resiliency events affecting the SPS service area.

Q. What risks do these resiliency events pose to the SPS system?

A. These resiliency events impact certain elements of SPS's system in ways that drive outages. Based on the 1898 & Co. analysis over the period of 2010 through 2023, approximately 65.4% of SPS outages occurred during one of the resiliency events recorded by NOAA.[1] This finding demonstrates that major weather events significantly contribute to customer outages and highlights the need for resilience investment to mitigate these impacts.

Q. How does SPS currently work to maintain and improve system resiliency?

A. From an operations standpoint, SPS has a number of dedicated efforts to ensure the resiliency and reliability of its system. Three of SPS's key resiliency programs are (1) the Wood Pole Inspection and Treatment Program ("Wood Pole Program"), in which all poles are tested on a 12-year cycle and evaluated for replacement or trussing; (2) Assess and Rebuild Program, in which SPS provides an overhead assessment and rebuild on a three- to five-year cadence; and (3) the Feeder Performance Improvement Program ("FPIP"), in which SPS evaluates the

[1] 1898 & Co. measures SPS recorded outages by Customer Minutes Interrupted, or "CMI." See 1898 & Co. Report at Section 3.2.2.

frequency and duration of electrical interruptions at the feeder level and, when necessary, replaces underground tap and feeder cable. Additionally, SPS uses Advanced Capital Projects for specific pieces of equipment, such as conductor replacements or full rebuilds. These projects are generally prioritized based on a number of factors, including current line health, capacity, future growth, and specific customer needs. SPS poles and other assets are maintained according to National Electric Safety Code ("NESC") Grade B standards.

Q. Please elaborate on SPS's existing resiliency programs.

A. Regularly inspecting the health of poles is a crucial element in asset management and system resiliency, because wooden poles decay with time and exposure to elements and wildlife. To manage pole health, SPS's Distribution Operations conducts frequent assessments and maintains a continuous pole replacement schedule. Since 2020, SPS has invested approximately $109 million in over 21,000 wooden pole replacements on the distribution system through the Wood Pole Program.[2] The Wood Pole Program provides for a ground line inspection and remedial protective treatment for wood distribution and transmission poles. Wood poles are on a rotating cycle for inspection, with all wood poles receiving a visual inspection and poles older than 10 years old receiving an invasive ground line inspection, assessment, and remedial treatment to arrest any existing deterioration and prevent future damage from insects and fungi. Poles receiving an invasive inspection are assessed for remaining strength in the ground line region of the pole using a software program to calculate the remaining pole strength from

[2] Including in 2020, and for all of SPS service territory.

measurements of the pole and any defects. To further reduce outages related to pole failures, SPS's distribution construction standards were upgraded in 2014 to move from Grade C to Grade B for all new and rebuilt distribution poles. Construction Grade B includes an approximately 50% stronger pole class strength and 50% stronger guy strength than Grade C. Each pole inspected is classified as compliant with or not compliant with NESC guidelines. Poles found to be compliant with the NESC guidelines receive remedial treatments and remain in service. Poles found to be non-compliant with the NESC guidelines are prioritized for either replacement with Grade B construction or for ground line reinforcement to bring the pole into compliance with the NESC guidelines. Pole inspections have played and will continue to play an important part in identifying and mitigating pole failures.

As noted above, SPS also conducts an assessment of its overhead system for rebuilds on a three- to five- year cadence through the Assess and Rebuild Program. Aspects of the underground system are reviewed as a part of the program; however, the primary focus is the assessment of overhead pole equipment, including crossarms, cutouts, arresters, conductors, jumpers, insulators and other supporting equipment, and hardware. The program is intended to capture defects and resolve issues prior to failure. Maintaining cross arms is another crucial element in asset management and system resiliency. SPS transitioned to a fiberglass crossarm standard approximately 10 years ago and has had improvements in crossarm failure rates as a result. Prior to this transition, wooden crossarms were standard, and like wooden poles, the crossarms were susceptible to

weather degradation and weakening over time. Crossarms can also fail due to changes in conductor tensions driven by galloping cables, excessive cable sags, damaged poles, and more. Fiberglass crossarms, being stronger and resistant to degradation, are now utilized for Grade B construction standards. SPS replaced approximately 21,000 crossarms in Texas between 2020 and 2022. Since the inception of the Assess and Rebuild Program in 2017, SPS has resolved defects at over 49,000 locations, the majority of which have been related to crossarms.

Finally, through the FPIP program, SPS works to identify the worst performing feeders within its service territory and to develop and implement projects to improve system reliability. On an annual basis, SPS compiles a list of distribution feeders and ranks them based on multiple reliability metrics. The feeders are evaluated, and projects are created to improve the reliability of the feeder.

Consistent with the Resiliency Rule (16 TAC § 25.62), SPS intends to significantly increase the amount of hardening work that will be accomplished through the Overhead Hardening measure of its proposed SRP. Activities included in the Overhead Hardening measure consist of incremental actions beyond SPS's current activities in the three existing resiliency programs I have outlined. And, as discussed in the next section of my direct testimony and by other SPS witnesses, SPS's proposed Distribution System Protection Modernization and Operational Flexibility measures will further support distribution system resiliency.

IV. PLAN IMPLEMENTATION AND EXECUTION

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I discuss SPS's implementation strategy for the Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures. I also address the Defensible Space Around Poles ("DSAP") for vegetation management and the wood substation conversion activities within the Wildfire Physical Mitigation Program elements of the Wildfire Mitigation measure that is otherwise addressed by SPS witness Anne Z. Sherwood. I also discuss how SPS plans to execute on its SRP, including costs, contracts, supply chain and materials procurement, and the timeline for completion. SPS witness Wendall A. Reimer discusses implementation of the Communication Modernization measure.

Q. What was Distribution Operations' role in developing the SRP?

A. Distribution Operations provided distribution system data to 1898 & Co. and participated with 1898 & Co. as it studied SPS's system vulnerabilities and ongoing projects. Distribution Operations provided feedback to 1898 & Co. about implementation of the proposed SRP programs and assisted in the development of its SRP project prioritization framework. The prioritization framework, discussed in more detail by SPS witness Brianne Jole, is the manner in which SPS has prioritized and selected projects for inclusion in this SRP based upon the 1898 & Co. modeled benefit-to-cost ratio and wildfire risk in SPS's Texas service territory. Just as this project prioritization framework guided SPS's selection of the measures and projects in the development of this SRP, the project prioritization framework

will guide the implementation sequence of projects and activities included in SPS's SRP measures.

Q. Please summarize the estimated costs associated with SPS's implementation of its proposed SRP.

A. Attachment CSM-1 summarizes the estimated costs associated with SPS's implementation of its proposed SRP by measure.

Q. What are the relevant cost drivers that impact these estimates?

A. SPS is confident in its cost estimation process, based on historical projects of similar scale, industry knowledge, collaboration with its vendors, and intra-company experience implementing measures like those proposed in the SRP. The cost drivers for each measure, including the estimated structures, equipment, and mileages associated with SPS's proposed programs, are discussed in the SRP in subsection 4 of each measure description in Section IV.

Q. Will SRP expenditures be kept separate from base Operations expenditures?

A. Yes. SPS witness Brooke A. Trammell explains how SPS will account for them and maintain separate records for SRP projects.

Q. Is SPS requesting flexibility in the implementation of the SRP?

A. Yes. SPS is requesting flexibility in the implementation of its SRP to ensure that it can adapt to changing conditions and incorporate new technologies as they become available. Specifically, SPS is seeking flexibility to adjust the selection of proposed programs within measures, or to adjust budgets and expenses between measures, without changing the total cost of the overall plan as approved to accommodate potential changes in conditions or technologies as they are encountered. SPS is

also seeking flexibility in terms of its business operations, timing, and methods for implementing the SRP.

Q. Does SPS propose a method for tracking its implementation of the Plan?

A. Yes. SPS will utilize its work and asset management system, SAP, to plan and track work. SPS will also use data visualization and reporting programs such as Power BI.

Q. Please explain how SPS will implement the full suite of programs in its SRP.

A. SPS implements large projects and programs through planning, engineering, and design, construction, and close-out processes. To determine the best implementation method for each SRP program, SPS will evaluate the scope and technical expertise required to complete the program. The planning process involves initial scoping of the project to identify permitting and material procurement needs and helps to identify key constraints that could impact timelines and budgets. Long-lead-time and high-volume materials and services are generally ordered and begin well in advance to ensure no major impacts to the timeline. The engineering and design process involves a detailed review of the scope of work and site visit to ensure equipment identified for replacement is justified and sized appropriately based on loading conditions. The construction phase typically begins several weeks after scoping and pre-construction. In the construction phase, SPS sets detailed schedules, coordinates permits and contractors, reporting, field assessments, minor project adjustments, and quality assurance and quality control activities. After construction is completed, work continues with final as-built documentation, financial work closure, and project close-out. SPS uses this process

whether it is completing the process using internal resources or local vendors.

Alternatively, SPS may use full engineering, procurement, and construction ("EPC") contracts to implement SRP measures. EPC contracts are with large vendors who take SPS-established standards for a project and design, engineer, and complete work to meet those standards. When using EPC contracts, SPS is responsible for establishing scope and managing the contract. EPC contracts stand in contrast to alternative implementation methods, such as working with local vendors with long term unit-based contracts.

A. Measure Implementation: Overhead Hardening, Distribution System Modernization, and Operational Flexibility

Q. How does SPS propose to implement the Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures, and the DSAP and wood substation conversion activities of the Wildfire Mitigation Program?

A. SPS will use its partner vendors, internal resources, or full EPC contracts to deliver the programs in each of the SRP's proposed measures. SPS will define the parameters for each program, including managing labor, setting and tracking milestones, and ultimately execution of each program.

Q. Will any of the Overhead Hardening, Distribution System Protection Modernization, or Operational Flexibility measures, or DSAP or wood substation conversion activities require transmission system outages?

A. For Overhead Hardening measure and DSAP activity, SPS does not expect that execution of the SRP will require transmission system outages. For the Distribution

System Protection Modernization and Operational Flexibility measures, and the wood substation conversions, implementation of some projects may require brief transmission outages. SPS will evaluate each project to determine options for completion of the work that would eliminate or minimize impacts to customers and the bulk electrical system. SPS will coordinate any outages with Southwest Power Pool, Inc., per standard procedures.

Q. Will any of these measures require SPS to coordinate with any government entities or programs?

A. From an operations stand point, generally, no. SPS coordinates with government entities in its normal course of business, for compliance, permitting, or other regulatory reasons. SPS witness Ms. Trammell discusses coordination with government entities related to government-sponsored funding opportunities.

Q. What is the timeline for implementing the SRP?

A. SPS proposes to conduct work in each of the SRP's proposed measures and activities throughout the duration of the SRP period. Work will begin in 2025 and continue through 2028.

Q. What has SPS used to develop its cost estimates for the measures and activities?

A. SPS based its cost estimates on historical projects of similar scale, industry knowledge, collaboration with its vendors, intra-company experience implementing measures like those proposed in our SRP, and reasonably anticipated supply and demand pressures. For instance, for measures addressing wildfire risk, including the Overhead Hardening measure and the Wildfire Mitigation measure,

SPS anticipates it will use some of the same vendors that currently serve SPS's affiliate Public Service Company of Colorado in implementing measures similar to its 2020 Wildfire Mitigation Plan.

With respect to programs proposed under the Distribution System Protection Modernization measure, many of the costs may be equipment costs, which are subject to some fluctuation based on supply chain issues, inflation, and other market constraints.

Additionally, as a project is ongoing, SPS is routinely updating cost estimates based on institutional knowledge of supply chain constraints, inflation, and other market pressures that impact the price of materials and labor it sources.

B. Materials

Q. How will SPS identify and procure the materials required to perform new and ongoing work?

A. SPS's typical procurement process proceeds as follows: (1) the project scope of work is designed and engineered according to common construction standards (compliant with regulation and industry standards); (2) SPS's sourcing group creates contracts for the commonly-used materials, which establishes competitive pricing for materials, standard materials are acquired through those contracts; and (3) SPS's design engineering group then determines a list of needed materials based on the scope of work. For programs implemented through EPC contracts, SPS anticipates that most of the material acquisition will continue to be handled through its standard processes. However, if there is a market advantage to certain materials being provided by the EPC vendors, SPS would consider the specific opportunity

and evaluate whether to take advantage of those opportunities.

Q. How does SPS's sourcing team manage lead time and material availability?

A. SPS maintains sufficient internal stock and inventory levels to satisfy its emergency and short-cycle material needs. SPS uses wholesale material contracts and vendors to provide direct-ship material and large quantities of materials for specific orders. Specific orders may be used when the volume of material is high, not on hand, or for large capital projects. Outside SPS's usual material supply, SPS determines project needs and projected quantities needed over time to develop a sourcing strategy. Like the industry more broadly, SPS generally uses a just-in-time stocking strategy, so that it has less unused material on hand at a given time. Under this model, SPS works with wholesale vendors who are responsible for stocking the inventory SPS relies upon. If an EPC vendor is used for program implementation, lead time and material supply would be managed by the vendor.

Q. Please explain how SPS's sourcing team works to obtain the best pricing for materials.

A. SPS employs a comprehensive supply chain management strategy to ensure it obtains the best pricing for materials. Some of the key practices SPS uses include:

1. Systematic Sourcing Method: SPS follows a five-step sourcing process that includes preparation, request for information, request for proposal, contract evaluation and negotiation, and implementation.
2. Market Intelligence and Business Analytics: A team dedicated to researching macro-level supply market conditions and developing cost models helps understand the requirements for labor, subcomponents, and raw materials,

which aids in negotiating better prices.

3. Supplier Relationships: SPS views its supplier relationships as strategic partnerships. It works closely with suppliers to control costs and deliver greater value, which ultimately helps keep customer bills low.
4. Local Sourcing: Whenever possible, Xcel Energy sources materials from local businesses within its eight-state service area. This not only supports local economies but also helps reduce costs associated with transportation and logistics.
5. Supplier Diversity Program: SPS has a strong focus on supplier diversity, which includes conducting outreach to diverse suppliers and encouraging their participation in procurement processes. This broadens SPS's supplier base and can lead to more competitive pricing.
6. By combining these strategies, SPS ensures it procures materials at the best possible prices, which helps keep customer bills low.

C. Contract Resources

Q. How does SPS propose to determine what contract labor resources will be needed to perform new and ongoing work?

A. Due to the incremental nature of the SRP and tight timelines, SPS will be contracting a significant portion of the work. Existing per-unit metrics along with holistic EPC agreements will be used in order to ensure timely completion of scope to budget. SPS does not need to precisely determine contractor schedules and resourcing as this is an obligation of the vendor. The vendor retains the responsibility for the delivery of the project scope.

Q. How will SPS ensure it will be able to secure the contract labor it needs to execute the SRP programs?

A. SPS's Variable Resource and Contracting group along with internal Sourcing departments ensures SPS has the right contracts in place to meet the labor needs of the operational budget. Partner vendors have a long history of proven success at meeting the variable resource needs of SPS; however, when these capabilities are stretched, EPC vendors will be used to holistically deliver the project while limiting the impact to SPS internal employees.

Q. Does SPS plan to leverage its master services agreements to secure services for its SRP?

A. Yes, to the extent practicable, SPS will utilize existing and new master service agreements to ensure adequate services to deliver on the SRP. Existing master service agreements will allow for pre-existing terms and conditions between parties and reduce negotiation times between SPS and potential vendors. In many cases, existing contracts are already established and will allow for quick turnaround at competitive pricing.

D. Timeline

Q. Please describe SPS's proposed schedule for implementing its SRP.

A. As discussed above, SPS will implement the SRP measures for at least three years, beginning in 2025 (pending approval by the Commission and the timing of that approval) through 2028.

Q. Does SPS's proposed implementation schedule account for the possibility of construction and other implementation delays?

A. SPS has identified measures, and programs within those measures, that it reasonably anticipates being able to implement given its current understanding of its operational and business needs, financial conditions and constraints, and supply chain or labor conditions.

V. PLAN METRICS

Q. Is SPS proposing metrics for evaluating the effectiveness of the measures it proposes in this SRP?

A. Yes, it is. SPS is proposing metrics that collectively cover all measures. I discuss the metrics associated with Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility. Wildfire Mitigation metrics are addressed by Anne Z. Sherwood; Communication Modernization metrics are addressed by Wendell A. Reimer. Detailed explanations of all metrics are provided in Section V of the SRP.

A. Distribution Overhead Hardening

Q. What metrics will SPS use for evaluating the effectiveness of the Distribution Overhead Hardening measure?

A. SPS proposes the following metrics for evaluating the effectiveness of the Distribution Overhead Hardening measure:

- Rolling 10-Year Average SAIDI;
- Underperforming Area Count;
- Storm Restoration Duration;

- Average Hardened Protection Zone ("AHPZ") CI vs Average Protection Zone ("APZ") CI Comparison by County (Hardened Only); and
- AHPZ CI Percentage Improvement.

Q. Why are these metrics appropriate for evaluating the effectiveness of the Distribution Overhead Hardening measure?

A. The Distribution Overhead Hardening measure is designed to reduce customer interruptions and restoration durations. Each of the five metrics proposed to evaluate the effectiveness of SPS's proposed Distribution Overhead Hardening work measures reductions in customer interruptions or restoration durations for major events. Specifically, system average SAIDI performance measures the average time of service interruption for the average customer; the Underperforming Area Count metric measures reliability improvements in underperforming areas of the SPS System; the Storm Restoration Duration metric measures improvements in SPS's ability to restore service after major events; the APHZ vs APZ CI Comparison by County metric measures improvements in outages on hardened lines compared to non-hardened lines in the same area and the AHPZ CI Percentage Improvement metric measures the same comparison, but on a system level.

B. Distribution System Protection Modernization

Q. What metrics will SPS use for evaluating the effectiveness of the Distribution System Protection Modernization measure?

A. SPS proposes use of the Rolling 10-Year Average SAIDI, Underperforming Area Count, and Storm Restoration Duration metrics for evaluating the effectiveness of the Distribution System Protection Modernization measure.

Q. Why are these metrics appropriate for evaluating the effectiveness of the Distribution System Protection Modernization measure?

A. The Distribution System Protection Modernization measure is designed to reduce customer interruptions and restoration durations. Each of the three metrics proposed for evaluating effectiveness of SPS's proposed Distribution System Protection Modernization work measures reductions in customer interruptions and restoration durations for major events. For instance, system average SAIDI performance measures the average time of service interruption for the average customer, the Underperforming Area Count metric measures reliability improvements in underperforming areas of the SPS System. and the Storm Restoration Duration metric measures improvements in SPS's ability to restore service after major events.

C. Operational Flexibility

Q. What metrics will SPS use for evaluating the effectiveness of the Operational Flexibility measure?

A. SPS proposes use of the Rolling 10-Year Average SAIDI metric for evaluating the effectiveness of the Operational Flexibility measure. Section V of the SRP includes a detailed description of the metric and its calculation.

Q. Why is the Rolling 10-Year Average SAIDI metric appropriate for evaluating the effectiveness of the Operational Flexibility measure?

A. The Operational Flexibility measure is designed to reduce the average time of service interruption for the average customer. System average SAIDI performance

measures the average time of service interruption for the average customer. The Rolling 10-Year Average SAIDI will reflect the effectiveness of the Operational Flexibility measure by showing reductions in outages stemming from transmission assets and transmission and distribution substations.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

AFFIDAVIT

STATE OF TEXAS)
)
COUNTY OF POTTER)

CASEY S. MEEKS, first being sworn on his oath, states:

I am the witness identified in the preceding testimony. I am over 18 years of age, of sound mind, and am capable of making this affidavit. I have read the testimony and the accompanying attachments and am familiar with the contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

CASEY S. MEEKS

Subscribed and sworn to before me this 9th day of December 2024 by CASEY S. MEEKS.

BRANDYI AMMONS
My Notary ID # 126836806
Expires March 13, 2025

Notary Public, State of Texas

My Commission Expires: March 13, 2025

Southwestern Public Service Company

SRP Estimated Spend by Implementation Year

Southwestern Public Service Company

System Resiliency Plan

Estimated Spend by Implementation Year

2025-2028 SRP Capital and Operations & Maintenance Expenses by Measure

	2025		2026		2027		2028		Total Plan	
Measure	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Overhead Hardening	$19.5M		$56.1M		$75.7M		$101.7M		$253.0M	
Distribution Modernization	$8.1M		$19.4M		$28.3M		$36.5M		$92.3M	
Communication Modernization			$34.2M		$37.1M		$41.4M		$112.7M	
Wildfire Mitigation	$2.5M	$2M	$7.6M	$4.5M	$8M	$5.20	$1.7M	$5.1M	$19.8M	$16.8M
Op. Flex	$3.1M		$10.1M		$23.8M	$0.002M	$6.7M	$0.004M	$43.7M	$0.006M
							Total		$521.5M	$16.8M
							Total Capital and O&M		$538.3M	

DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF A TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY
of
BRIANNE R. JOLE

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

(Filename: Direct_Testimony_Jole.docx; *Total Pages:* 45)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AI	Artificial Intelligence
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
Commission or PUCT	Public Utility Commission of Texas
EDM	EDM International, Inc.
EPSS	Enhanced Powerline Safety Settings
FLISR	Fault Location Isolation and Service Restoration Program
NESC	National Electric Safety Code
NOAA	National Oceanic & Atmospheric Administration
O&M	Operations & Maintenance
pLTE	Private LTE
RTU	Remote Terminal Unit
SPS	Southwestern Public Service Company, a New Mexico corporation
SRP or Plan	Southwestern Public Service Company's System Resiliency Plan
TAC	Texas Administrative Code
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

LIST OF ATTACHMENTS

Attachment	**Description**
BRJ-1	Resume of Brianne Jole (*Filename:* Brianne_Jole_Resume)

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Brianne R. Jole. My business address is 4201 Frankford Avenue, Lubbock, Texas 79401.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") and a wholly owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by Xcel Energy Services Inc. ("XES"), the service company subsidiary of Xcel Energy, as Manager, System Planning and Strategy, Distribution Integrated Planning.

Q. Please briefly outline your responsibilities as Manager, System Planning and Strategy, Distribution Integrated Planning.

A. I lead a team of engineers who are responsible for planning the distribution system to ensure reliability, resiliency, new growth, and that SPS strategically plans its distribution investments to serve the best interests of new and existing customers.

Q. Please describe your educational background.

A. I graduated from Texas Tech University with a bachelor's degree in mechanical engineering in 2016. I obtained my professional engineering licenses in both Texas and New Mexico in 2021.

Q. Please describe your professional experience.

A. I began my employment with SPS in Seminole, Texas as a distribution design engineer in the distribution design engineering department. In October 2023, I accepted my current position with XES. In that role, I have worked to provide new service to customers, address how all customers across Xcel Energy apply for and receive service and manage resiliency projects across the SPS footprint. My resume is included as Attachment BRJ-1 to my direct testimony.

Q. What was your role in the development of SPS's System Resiliency Plan ("SRP" or the "Plan")?

A. I was actively involved in planning, selecting, and designing the programs and measures in the SRP, including in the direction and coordination between SPS and 1898 & Co., the third-party consultant that assisted SPS in the evaluation of potential resiliency measures. Specifically, I provided 1898 & Co. with SPS data and worked with the 1898 & Co. project team to scope the measures, programs, and activities; model the benefits of the proposed resiliency investments; and perform the benefit-cost analysis ("BCA") for certain measures included in the Plan.

Q. Which sections of the SRP do you sponsor?

A. I sponsor or co-sponsor Sections III and IV.A, B, and D of the SRP, addressing SPS's Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures.

Q. Have you previously testified before any regulatory authorities?

A. Yes. I previously testified on behalf of SPS before the New Mexico Public Regulation Commission in the 2024 Transportation Electrification Plan filing. I

have not previously provided testimony before the Public Utility Commission of Texas ("PUCT" or "Commission").

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to support SPS's request for approval of the Plan. My direct testimony: (1) describes SPS's approach to resilience, including current and ongoing initiatives and the factors SPS prioritized in developing the SRP; (2) introduces the measures proposed in the SRP; (3) describes SPS's coordination with 1898 & Co., the independent consultant that evaluated potential SRP investments; and (4) describes and provides support for the measures I sponsor, including the Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures.

Q. Please summarize your direct testimony.

A. SPS is proposing an SRP that is tailored to the unique needs of its service area and customers. The proposed measures in the SRP will address the most significant resiliency risks facing the SPS system today. These measures are designed to work in conjunction with one another, and with SPS's existing programs, to enhance SPS's ability to prevent, withstand, mitigate, and more promptly recover from extreme weather, wildfire, and cybersecurity events that pose a material risk to the safe and reliable operation of the SPS system.

SPS engaged 1898 & Co., an independent consultant with expertise in resilience and risk modeling to assist with the design, selection, and evaluation of potential measures. As SPS witness Mr. Jason De Stigter of 1898 & Co. explains

in his direct testimony, the SRP is a portfolio of resiliency investments that will provide benefits to customers in excess of its costs. These benefits include fewer customer outages, faster service restoration when outages occur, and avoided system restoration costs. In addition, customers will benefit from reduced wildfire risks, general safety benefits, and improved overall reliability during and after a resiliency event.

Specifically, the Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures will protect the SPS system and customers against outages caused by weather-based resiliency events, while accelerating SPS's wildfire prevention and protection efforts.

Q. What action do you recommend regarding the SRP?

A. I recommend that the Commission approve all of the proposed investments in the SRP, including in the Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures, at the investment level requested by SPS.

III. SPS APPROACH TO RESILIENCY

Q. How does SPS approach investments in resiliency?

A. SPS's approach to resiliency investment includes: (1) mitigating resiliency events and vulnerabilities that pose the greatest risk to SPS customers; (2) selecting investments to advance long-term resiliency objectives; (3) incorporating lessons learned from SPS's extensive experience providing electric service; and (4) targeting impactful and cost-effective investments to maximize value to SPS customers.

Q. How did these objectives influence SPS's development of the SRP?

A. Hardening distribution facilities, modernizing protection systems, and combatting wildfire-related risks are long-term resiliency objectives for SPS. In this SRP, SPS is proposing a proactive, comprehensive portfolio of resiliency investments with a focus on these three objectives. SPS relied on knowledge gained through decades of experience providing electric service in the Texas Panhandle and Texas South Plains, including lessons learned from recent resiliency events and input from independent experts with relevant expertise, to select investments that will maximize the customer benefit for every dollar SPS invests under this SRP. These investments will target the most impactful resiliency events and risks for the SPS system, including wildfires, winter and ice storms, and thunderstorm winds.

Q. What measures is SPS proposing in its SRP?

A. SPS is proposing five measures, consisting of various programs and activities, including:

Distribution Overhead Hardening – The activities in this measure include replacing and reinforcing distribution poles, replacing conductor, replacing line transformers, replacing open-wire secondary, mitigating long span-lengths, and, in heightened wildfire risk areas, wrapping poles with fire resistant coatings and replacing arrestors and transformer fuses with non-expulsion alternatives.

Distribution System Protection Modernization – The activities in this measure include installing sectionalizing reclosers, installing tie reclosers, installing communications equipment on existing reclosers, replacing substation relay panels, replacing substation breakers, installing lateral reclosers, and

performing studies to optimize protection schemes with new equipment. Additionally, in areas of heightened wildfire risk, SPS will install fault current indicators and replace tap-level fuses with non-expulsion alternatives.

Communication Modernization – The activities in this measure include building out a private LTE network ("pLTE"), installing Fiber Optic cable, and adding remote terminal units ("RTUs") at select substations.

Operational Flexibility – The activities in this measure include procuring mobile substation equipment and installing additional switching devices on select transmission circuits.

Wildfire Mitigation – The activities in this measure include acquiring weather stations to enhance SPS's meteorological capabilities, adopting weather and fire science modeling, deploying Artificial Intelligence ("AI") cameras to more effectively detect wildfire threats, vegetation management to create defensible spaces around structures, wood substation conversions, and detailed visual inspections.

Q. How did SPS select the measures, programs, and investments proposed in the SRP?

A. Consistent with its overall approach to resiliency investment, SPS selected measures, programs, and investments that (1) mitigate the resiliency events and risks that impact the SPS system, with a specific focus on wildfire; (2) leverage the expertise of third-party consultants, including the benefit-cost ratio ("BCR") as reported by 1898 & Co., which accounts for the historical performance of the system during resiliency events; and (3) optimize the overall size of the Plan, with

consideration for the costs to customers and SPS's ability to execute on the full portfolio of proposed investments in the next three years. These principles guided SPS's development of the Plan and form the basis of SPS's framework for prioritizing resiliency investments. SPS witness Mr. De Stigter provides additional details on how BCR values were calculated and the numerous variables they represent (*e.g.*, event frequency, asset age and vulnerability, rebuild costs, etc.). SPS also engaged EDM International Inc. ("EDM") to provide third-party expertise regarding wildfire resiliency and details regarding that work are provided in the direct testimony of SPS witness Ryan Brockbank of EDM.

Q. How will SPS prioritize projects for execution?

A. SPS's project prioritization framework will (1) direct investments to parts of the system where the wildfire risk is highest and then (2) utilize the BCR value for all projects within that area to further prioritize investments. This framework will address wildfire-related risks while prioritizing the most impactful and cost-effective projects.

Q. Outside of the Wildfire Mitigation measure, what is the relationship between the proposed SRP measures and wildfire risk?

A. While the Distribution Overhead Hardening and Distribution System Protection Modernization measures were developed with general resiliency at the forefront, all investments proposed under these measures inherently support wildfire ignition risk reduction by mitigating the likelihood of equipment failure and isolating downed or faulted facilities. For example, approximately 92% of SPS's proposed investment under the Distribution Overhead Hardening measure is in areas of

heightened wildfire risk, as is approximately 72% of the investment proposed under the Distribution System Protection Modernization measure. These measures include additional wildfire-focused activities in areas of heightened wildfire risk.

Additionally, the pLTE tower locations for the Communication Modernization measure were selected to maximize cellular coverage in areas of heightened wildfire risk, as described in more detail in the direct testimony of SPS witness Wendall Reimer.

Wildfire spread risk is highest during high-wind events, which are also the most frequent, and among the most impactful, weather-related resiliency events on the SPS system. Therefore, many measures and programs that target weather-based resiliency events will mitigate wildfire risk as well, allowing SPS to comprehensively address multiple resiliency risks at the same time.

Q. Does SPS have existing programs that make the system more resilient?

A. Yes. SPS's existing programs focus on proactive inspection and replacement, targeted upgrades, and advancing SPS's strategic objectives. A key objective for SPS is hardening its transmission and distribution systems. As detailed in a recent report to the Commission, SPS's storm hardening philosophy is to install overhead lines that meet or exceed the needs of its service area.[1]

In 2014, SPS transitioned from Grade C to Grade B construction standards for all new and rebuilt overhead facilities. Grade B is the highest grade of construction under the National Electric Safety Code ("NESC") and results in the

[1] *See Reports of Storm Hardening*, Project No. 39339, SPS Storm Hardening Report at 2 (May 1, 2024).

highest strength and largest safety factors for overhead distribution lines. Adopting this standard ensures that all new and rebuilt distribution facilities are hardened against resiliency events that impact the SPS service area.

Additionally, SPS has the following periodic inspection and maintenance programs, which SPS witness Casey Meeks discusses further in his direct testimony:

Wood Pole Inspection and Treatment – This program involves ground line inspection of wood poles and corresponding remedial protective treatment.

Routine Overhead System Maintenance – Through this program, SPS performs patrols and rebuilds, as necessary, on a three-to-five-year cadence.

Feeder Performance Improvement Program – Under this program, SPS investigates and takes corrective action on poor-performing feeders based on the frequency and duration of outages experienced over the prior year.

Two other SPS programs historically target select facilities for upgrades:

Advanced Capital Projects Initiative – This program identifies areas that need additional hardening based on line condition, specific operating concerns, flexibility, and customer impacts.

Fault Location Isolation and Service Restoration Project ("FLISR") – Under this program, SPS deploys automated protective devices, such as reclosers, that are integrated with SPS's Advanced Distribution Management System ("ADMS"). This effort targets a limited number of feeders, which are selected based on the number of outages impacting the mainline each year. SPS began its multi-year deployment of FLISR in 2023.

Q. Will these existing programs continue once SPS begins making new resiliency investments through the SRP measures?

A. Yes. The measures and programs in the SRP will work in conjunction with the existing programs to reduce costs and accelerate the continuous improvement in service that SPS customers, the Commission, and the Texas Legislature have come to expect from SPS.

For example, work completed under the existing inspect-and-replace programs will reduce costs associated with the Distribution Overhead Hardening measure. When performing rebuilds under Distribution Overhead Hardening, SPS will not replace facilities installed after 2014 that meet its current hardened standards. This means that most assets replaced under one of the existing programs in the last 10 years will not need replacement. Similarly, the Distribution System Protection Modernization measure will not replace the FLISR program. Instead, it will accelerate SPS's deployment of automated protective devices. The two will work in conjunction with one another to modernize SPS's distribution system protection.

Q. How will SPS customers benefit from approval of SPS's SRP?

A. Approval of the SRP will authorize SPS to begin making additional, systematic investments in system resiliency. The investments SPS proposes in the SRP focus primarily on the distribution system and provide quantified benefits to customers in the form of reduced frequency and duration of outages and avoided restoration costs. All customers across the SPS system will benefit from the reduction in restoration costs. In addition to these benefits, which were quantified in the 1898 &

Co. analysis, the SRP measures will also provide customers with qualitative benefits, including wildfire risk reduction, improvement in overall service reliability during and after resiliency events, and general safety benefits.

Q. Which measures in the SRP do you sponsor?

A. I sponsor the Distribution Overhead Hardening, Distribution System Protection Modernization, and Operational Flexibility measures, which I describe in greater detail in the following sections of my testimony. SPS witness Mr. Reimer sponsors the Communication Modernization measure, and SPS witness Ms. Sherwood sponsors the Wildfire Mitigation measure.

IV. COORDINATION WITH 1898 & CO.

Q. Please describe the coordination between SPS and 1898 & Co. in developing the SRP.

A. SPS engaged 1898 & Co. to perform a BCA of SPS's proposed SRP measures. SPS provided 1898 & Co. with SPS system data, costs estimates, details of potential measures and programs, and SPS's execution capabilities for the years 2025 to 2028. As described in the direct testimony of SPS witness Mr. De Stigter, 1898 & Co. used this information, along with National Oceanic and Atmospheric Administration ("NOAA") historical weather data, to model the costs and benefits of the proposed resiliency investments. SPS used the results of the BCA, in conjunction with the project prioritization framework described above, to select a comprehensive portfolio of cost-effective investments to include in SPS's initial SRP.

Q. What system data did SPS provide to 1898 & Co.?

A. SPS provided 1898 & Co. with data from its Geographic Information System, including the location of facilities, equipment installed, install dates, pole-testing data, and other information; customer data, including the number and locations of customers, the facilities they are served from, and customer type (*i.e.*, residential, commercial, industrial, or critical); and data from SPS's Outage Management System, including outage records, cause codes, and details of restoration. Additionally, SPS provided unit costs for various scopes of work.

Q. Did 1898 & Co. perform the same analysis for all five measures in the SRP?

A. No. 1898 & Co. evaluated the Distribution Overhead Hardening, Distribution System Protection Modernization, and Communication Modernization measures. SPS engaged EDM as a third-party consultant to assist with aspects of the Wildfire Mitigation measure. Mr. Brockbank's direct testimony addresses EDM's involvement in the SRP, as well as that wildfire mitigation programs and activities included in SPS's proposed SRP and Wildfire Mitigation Plan are consistent with other utilities.

Q. What conclusions can be drawn from the 1898 & Co. evaluation?

A. 1898 & Co.'s evaluation demonstrates that SPS's proposed SRP measures will be effective at making the SPS system more resilient against weather-based resiliency events. Each measure that 1898 & Co. evaluated will provide benefits to customers that significantly exceed the cost of the investment. Specifically, projects in the Distribution Overhead Hardening measure have an average BCR of 4.7.[2] This

[2] Because the Distribution Circuit Hardening Rebuilds program is the only program in the Distribution Overhead Hardening measure, the benefits of the measure are equivalent to the benefits for the program.

means that, on average, the customer benefits will exceed the project costs close to five times over. The 1898 & Co. evaluation estimates that the projects in this measure will result in a 58% average reduction in customer outages for the circuits where investment is made.

The Distribution System Protection Modernization measure includes two programs: Mainline Automated Reclosing Deployment and Lateral Reclosing Deployment. The proposed Mainline Automated Reclosing Deployment projects have an average BCR of 4.2 and an expected improvement in outages of 37%. The proposed Lateral Reclosing Deployment projects have an average BCR of 1.8 and an expected improvement in customer outages of 21%.

1898 & Co. also performed a combined BCA for the Mainline Automated Reclosing Deployment program and the Communication Modernization measure. This is because the investment in Communication Modernization is necessary for the Mainline Automated Reclosing Deployment program to function as intended. That analysis shows a combined BCR of 1.8. This does not account for the qualitative benefits of the two measures. As explained in more detail below, the Mainline Automated Reclosing Deployment program will provide additional benefits to customers by mitigating wildfire ignition risks. As Mr. Reimer's direct testimony explains, the Communication Modernization measure will provide additional benefits to customers by mitigating the risks posed by cybersecurity threats. This means that the 1.8 BCR value actually understates the benefits of the combined measures.

V. DISTRIBUTION OVERHEAD HARDENING

Q. Please describe the Distribution Overhead Hardening measure.

A. The Distribution Overhead Hardening measure is designed to harden the SPS distribution system against risks posed by weather-based and wildfire resiliency events. Events that stress overhead facilities beyond their ratings threaten their structural integrity, which can cause a downed distribution line that results in a customer outage.[3] This, in turn, can increase the risk of a spark igniting a wildfire. The Distribution Overhead Hardening measure includes a single program—the Distribution Circuit Hardening Rebuilds program—which consists of numerous activities designed to strengthen the structural integrity of facilities and mitigate the risk of SPS facilities causing an ignition.

The activities in this program include replacing distribution poles, conductor, line transformers, and open wire secondary; trussing/reinforcing distribution poles; adding new poles to mitigate long span-lengths; wrapping poles to mitigate external wildfire damage in heightened wildfire risk areas; and replacing arrestors and transformer fuses in areas of heightened wildfire risk with non-expulsion alternatives.

Q. What resiliency method does the Distribution Overhead Hardening measure utilize?

A. The Distribution Overhead Hardening measure uses the hardening electric transmission and distribution facilities method described in 16 Texas Administrative Code ("TAC") § 25.62(c)(1)(A).

[3] For example, a structure that is designed to withstand 40 mile-per-hour winds with concurrent ice load that experiences 60 mile-per-hour gusts.

Q. What are the resiliency events and risks the Distribution Overhead Hardening measure is designed to address?

A. The Distribution Overhead Hardening measure addresses risks posed by the following NOAA event categories, which are described in more detail in Section 3 of the 1898 & Co. report: (1) wind (e.g., high winds, thunderstorm winds, hail winds), which can (a) cause vegetation or debris to contact SPS facilities, potentially faulting or damaging equipment, (b) directly damage equipment, including by toppling poles or breaking conductor, and (c) cause structural overloads and galloping conductor when combined with ice or snow; (2) flood, including localized impacts that restrict access to structures during an outage event; (3) tornado, this measure can withstand or mitigate the impact from the surrounding winds but not the direct path of a tornado; (4) winter (*e.g.*, sleet, heavy snow, ice storms), which can delay restoration efforts and can also cause ice to accumulate on SPS facilities and surrounding vegetation, heavily loading structures and potentially resulting in a fault or damaged equipment; and (5) heat and cold, which are accompanied by increased power usage that strains equipment, potentially causing thermal overloads that limit the capability of SPS facilities to accommodate a load transfer when outages occur.

This measure also mitigates wildfire risks, including the external risk of wildfires damaging SPS facilities and the risk of SPS facilities causing a catastrophic ignition.

Q. How will the Distribution Overhead Hardening measure allow the SPS system to prevent, withstand, mitigate, or more promptly recover from these risks?

A. Facilities hardened under this measure will be rebuilt to Grade B construction standards, which is the highest grade of construction for overhead distribution facilities under the NESC. This will allow the hardened facilities to withstand or mitigate many resiliency events that pose a risk to the SPS system.

Poles will be replaced or trussed as needed to ensure that structural integrity meets Grade B hardening standards. Replacing aged, small conductor and secondary wire will provide structural benefits to prevent or mitigate conductor failure and impacts from debris and vegetation contact. Where conductor replacement is the recommended solution, SPS will add poles as needed to shorten span lengths beyond what is required by Grade B loading standards to prevent conductor contact during high wind events, maintaining the health of the new conductor for decades to come. Conductor replacements will also provide additional capacity in many circumstances, as the new conductor will be of a larger size, which will mitigate the thermal impacts of high power-usage during extreme temperatures and increase the availability of facilities for load transfer, allowing SPS to more promptly recover when outages occur.

In areas of heightened wildfire risk, pole-wrapping will protect the structural integrity of poles during wildfires and replacing arrestors and fuses with non-expulsion equivalents will mitigate wildfire ignition risks.

Q. What is SPS's current standard for hardening its overhead facilities?

A. Since 2014, SPS has built all new distribution facilities to satisfy NESC requirements for Grade B construction, including limiting span lengths according to conductor size to meet pole loading requirements. All new conductor is, at a

minimum, #2 ACSR, with 2/0 preferred for long distances and in areas of heightened wildfire risk, and SPS now uses lashed cable in place of open wire secondary. This conductor provides greater capacity and strength than the aged conductor it will replace.

Q. Does SPS have existing programs to upgrade legacy facilities to the current hardened standard?

A. Yes. As discussed above, SPS has multiple programs through which it periodically inspects, maintains, and upgrades facilities. These programs are covered in detail in Mr. Meeks' direct testimony.

Q. How is the Distribution Overhead Hardening measure different from SPS's existing overhead maintenance programs?

A. In contrast to the Distribution Overhead Hardening measure, SPS's existing programs rely on periodic inspection and maintenance to identify defects and replace individual assets. The Distribution Overhead Hardening measure involves comprehensive rebuilds of entire protection zones. A "protection zone" includes all assets protected by the nearest upstream protective device (*i.e.*, a breaker, recloser, or fuse). Section 5.1 of the 1898 & Co. report provides more detail how 1898 & Co. used protection zones to delineate projects for their BCA.

Under the Distribution Overhead Hardening measure, SPS will review and address all assets in each targeted protection zone at the same time, while also removing any small, aged conductor and open wire secondary and replacing aged transformers. This comprehensive scope of work will help to prevent or mitigate

outages on the entire protection zone rather than preventing the failure of individual assets.

Q. How does the Distribution Overhead Hardening measure address wildfire risks?

A. The facilities hardened under this measure will be less likely to experience a failure during resiliency events, which reduces the risk of SPS facilities causing an ignition. Additionally, under this measure, SPS will install pole wraps around facilities in areas of heightened wildfire risk, to mitigate the risk of wildfire damaging distribution poles, and replace arrestors and transformer fuses in areas of heightened wildfire risk with non-expulsion alternatives, mitigating ignition risk during the operation of the asset.

Q. How will SPS customers benefit from the Distribution Overhead Hardening measure?

A. The ability of the hardened facilities to prevent, withstand, mitigate, or more promptly recover from the risks posed by resiliency events will result in fewer customer outages and faster restoration times in many cases when outages occur. Customers will also benefit from reduced restoration costs because hardened assets will be more likely to withstand resiliency events. These benefits and others are discussed in greater detail in the 1898 & Co. report, which quantifies and monetizes customer benefits from reduced system restoration costs, fewer customer outages, and decreased outage durations.

Q. Why did SPS choose the Distribution Overhead Hardening measure over any reasonable and readily identifiable alternatives?

A. The Distribution Overhead Hardening measure is the most cost-effective solution for the projects selected in the Plan, as it allows all issues in the protection zone to be addressed at one time in a strategic and efficient manner. Projects selected for improvement under this measure have a minimum BCR of 3.22, meaning all proposed projects will provide over three times the benefits to customers as the cost to harden the circuit.

SPS identified and considered two potential alternatives to this measure: (1) undergrounding, and (2) staying on the same inspect, test, replace cycle utilized today. Neither of these alternatives provided benefits equivalent to the Distribution Overhead Hardening measure.

Undergrounding facilities on a widespread basis is not cost-effective in SPS's service area. Undergrounding can cost 5 to 10 times as much per mile as fully rebuilding the lines overhead and results in significant voltage losses as the distance between substations increases. Undergrounding can also increase restoration times for radially fed customers. SPS has many long, radial distribution lines that serve relatively few customers, owing to the size and rural character of SPS's service area. Therefore, undergrounding would increase the costs of hardening but provide limited, if any, additional benefits.

Staying on the same inspect, test, and replace cycle that SPS is on today would not capture the resiliency benefits identified by the 1898 & Co. analysis. Existing programs are designed to identify potential structure failures and can miss cost-effective opportunities to bring the entire protection zone into Grade B rather than just the structure. As explained in the 1898 & Co. report, the failure of a single

asset in a protection zone can cause the entire protection zone to experience an outage. Therefore, the comprehensive rebuilds under this program will provide a greater resiliency benefit.

Q. Do the BCR results for the Distribution Overhead Hardening measure account for any circuit upgrades completed under the Distribution System Protection Modernization measure?

A. Yes. In their modeling, 1898 & Co. reduced the benefits in the Distribution Overhead Hardening measure for feeders selected for investment under the Distribution System Protection Modernization measure. This adjustment was made to avoid accidental double-counting of benefits. Additional details on this approach are addressed in section 2.4.2 of the 1898 & Co. report.

Q. How will SPS prioritize the selected facilities for rebuilds under the Distribution Overhead Hardening measure?

A. Consistent with SPS's prioritization framework, SPS will prioritize facilities for rebuilds based on the wildfire risk in the area and the BCR.

Q. What is the scope of SPS's proposed investment under the Distribution Overhead Hardening measure?

A. Under this measure, SPS will harden approximately 170 protection zones. This will include replacing or installing approximately 16,150 distribution poles, trussing approximately 1,690 poles, and wrapping approximately 14,760 poles in areas of heightened wildfire risk. SPS will replace approximately 780 miles of primary and 11 miles of secondary conductor, 515 transformers, 175 arrestors, and 450 transformer fuses.

Q. What are the estimated costs for the Distribution Overhead Hardening measure?

A. SPS estimates approximately $253 million of new capital investment for the Distribution Overhead Hardening measure.

Q. Can you provide an example of a Distribution Overhead Hardening project included in the Plan?

A. Yes. One project included in the Plan is a rebuild of a protection zone on circuit BURN1398 in Hutchinson County. This lateral circuit lies in SPS's highest wildfire risk area, is approximately 1.76 miles long, and currently has 30 poles, with an average span-length of 310 feet. The average age of the equipment on this protection zone is 55 years, and it serves two small commercial and industrial ("C&I") customers and eight large C&I customers.

The recommended solution for this zone is to replace 25 of the aged poles with 12 new poles to mitigate long span-lengths, resulting in a new average span length of 222 feet, and to replace all conductor in the zone. Additionally, to address the elevated wildfire risk in the area, SPS will replace two transformer fuses and wrap 37 poles. The estimated cost of this project is approximately $480,000, and the total quantified benefits based on the 1898 & Co. analysis are $2.2 million in avoided outages and restoration costs, resulting in a BCR of 4.9. While this circuit only serves 10 customers, all customers on the SPS system will share in the avoided restoration costs from these improvements. This protection zone will also be less likely to fail in the future, allowing SPS crews to restore service to other customers more quickly.

VI. DISTRIBUTION SYSTEM PROTECTION MODERNIZATION

Q. Please describe the Distribution System Protection Modernization measure.

A. The Distribution System Protection Modernization measure consists of two programs designed to modernize protection schemes and bring devices into SPS's ADMS. This will enable SPS to remotely monitor line conditions and remotely control protective devices on distribution facilities. The Mainline Automated Reclosing Deployment program includes activities such as installing additional reclosers to further sectionalize mainline facilities, installing reclosers at ties between circuits for automated switching, installing communications equipment on existing reclosers, upgrading reclosers with equipment that can accept communications, replacing substation breakers and relay panels with modern, communications-enabled equipment that can be remotely operated, and implementing modern protection schemes with new equipment. Additionally, in heightened wildfire risk areas, SPS will install fault indicators and replace tap-level fuses with non-expulsion alternatives. Under the Lateral Reclosing Deployment program, SPS will install reclosers on select lateral lines.

Q. What is a recloser?

A. A recloser is a switching device that is paired with a microprocessor-based relay that can detect and respond to faults. When a recloser detects a fault on the system, it trips open to interrupt the flow of power and the fault current. Normally, after tripping open, the recloser will reset itself to restore power if it determines the fault has cleared. Reclosers can also be programmed to not automatically reset themselves under certain conditions, such as during times of heightened wildfire

risk or when crews are working on downstream facilities. This allows reclosers to quickly interrupt the flow of power during faults that may otherwise result in a thermal event (*e.g.*, sparks, employee contact with the line) that could potentially cause an ignition.

Q. What resiliency method does the Distribution System Protection Modernization measure utilize?

A. The Distribution System Protection Modernization measure uses the modernizing electric transmission and distribution facilities method, as described in 16 TAC § 25.62(c)(1)(B).

Q. What resiliency events and risks is the Distribution System Protection Modernization measure designed to address?

A. Like the Distribution Overhead Hardening measure, the Distribution System Protection Modernization measure will address risks posed by wind, flood, tornado, winter, heat, cold, and wildfire events. However, the Distribution System Protection Modernization measure will provide a different set of capabilities, primarily through the deployment of communications-enabled reclosers that will mitigate those events and allow the SPS system to more promptly recover when outages occur.

Q. How will the Distribution System Protection Modernization measure allow the SPS system to prevent, withstand, mitigate, or more promptly recover from the risks posed by resiliency events?

A. In conjunction with protection schemes to isolate faults, the ability of reclosers to detect faults, interrupt power flow, and reset themselves can allow service to be

automatically restored to many customers quickly following a temporary fault. A large proportion of faults on the overhead system are temporary in nature. Temporary faults commonly occur during wind events due to debris or vegetation momentarily contacting conductor, contact between two conductors, or other, unknown causes.

Communications-enabled reclosers will work with SPS's ADMS to sectionalize the distribution system, isolate faults, and restore service to sections of the system that were not directly impacted by the fault. This can minimize the impact of a fault caused by a broken conductor or damaged equipment during weather events and reduce the number of customers that experience an outage. Moreover, the sectionalizing capabilities reclosers provide can be used to redirect power flows and transfer customer load between facilities, which can mitigate the risk of overloading during extreme temperature events.

Q. How does SPS approach distribution protection standards?

A. SPS collaborates with the Distribution System Protection Technical Committee, comprised of distribution engineers who are subject matter experts in operations and system protection from across the distribution engineering organization, to develop and maintain system protection standards. The committee reviews the standards quarterly and makes necessary changes based on emerging technology, persistent issues on the system, and any specific challenges that need to be addressed.

Modernizing SPS's distribution protection schemes involves the implementation of enhanced powerline safety settings ("EPSS") in areas of

heightened wildfire risk. This is covered in greater detail in section IV.B. of the SRP. As part of the Distribution System Protection Modernization measure, study work for all protection schemes needed for new equipment, including for EPSS, will be accomplished at the same time to allow for the efficient use of resources.

Q. Does SPS have existing programs to upgrade legacy facilities to the current system protection standard?

A. Yes. Like the existing pole-hardening programs discussed above, SPS periodically reviews specific locations to ensure equipment is fully functioning and replaces assets as needed to maintain operability. SPS maintains existing equipment on its system and replaces equipment that has reached its end-of-life. As with other programs that will be built upon through the SRP, these existing activities are based on point-to-point maintenance of assets in the field, upgrading them during the replacement. SPS also uses the FLISR program to integrate protective equipment on select feeders to locate faults, isolate faulted sections, and restore service automatically through ADMS, where possible.

Q. How are the programs in the Distribution System Protection Modernization measure different from SPS's existing modernization programs?

A. Under this measure, SPS will modernize all equipment on entire circuits, review protection schemes, and optimize device placement, including adding new devices where warranted, rather than simply replacing them where they currently exist. By taking the feeder-level approach, resources are optimized to modernize the entire feeder at once versus making multiple trips to the same area over time. This takes a comprehensive view of the circuit as a whole rather than just addressing the

individual pieces of equipment, providing additional efficiencies that benefit all customers.

Compared with existing programs, the Distribution System Protection Modernization measure will significantly accelerate SPS's efforts to modernize its protection systems with equipment that can be remotely operated and communicated with. While similar in nature to the existing FLISR program, the Distribution System Protection Modernization measure leverages the 1898 & Co. analysis to select additional feeders to perform widespread upgrades and pod-size optimization. The feeders upgraded through this Plan will be in addition to the feeders upgraded through the FLISR program.

Q. How will SPS customers benefit from the Distribution System Protection Modernization measure?

A. Customers served from modernized facilities will experience reduced frequency and duration of outages, reduced restoration costs, and improved overall service reliability. Communications-enabled protective devices can coordinate to isolate faults, reducing the number of customers affected by an outage. They can quickly transfer customer load to an alternate source when an outage occurs to restore service more quickly for many customers. They can also identify and clear temporary faults without the need to deploy SPS personnel for manual switching. The addition of hundreds of connected devices will also increase visibility into the system, allowing SPS to more quickly and accurately locate a fault and deploy personnel, reducing the time to restore service when repair work is needed.

In addition to the quantified customer benefits, this measure will provide qualitative benefits such as mitigating wildfire ignition risks.

Q. How will SPS prioritize facilities for upgrades under the Distribution System Protection Modernization measure?

A. Consistent with the project prioritization framework described above, SPS will prioritize projects for execution based on wildfire risk in the area and BCR values. Where applicable, feeders will be grouped at the substation level to effectively deploy breaker and relay replacements.

Q. How will the proposed investment in a pLTE network under the Communication Modernization measure support the deployment of protective devices under the Distribution System Protection Modernization measure?

A. The reclosers, breakers, and protective relays installed under this measure rely on communications with other devices and the ADMS to fully enable sectionalization and load-transfer capabilities. As Mr. Reimer explains in more detail in his direct testimony, SPS currently relies on public cellular networks for communications between devices. Given the remoteness of SPS's service area, public carriers do not provide adequate coverage for device communications throughout much of the service area. Without cellular coverage, these devices are limited in their ability to isolate faults and transfer load. Building out SPS's pLTE network as proposed in the Communication Modernization measure will extend cellular coverage across the service area to enable the full functionality of the communications enabled protective relays, breakers, and reclosers SPS will deploy under the Mainline Automated Recloser Deployment program.

Q. Why did SPS select the Distribution System Protection Modernization measure over any reasonable and readily identifiable alternatives?

A. The Distribution System Protection Modernization measure is a proactive and cost-effective solution to protect the system from the risks posed by resiliency events. Projects in this measure have an average BCR of 4.20 for the Mainline Reclosing Deployment program and 1.80 for the Lateral Reclosing Deployment program. The Mainline Automated Reclosing Deployment projects are expected to result in a 37% outage reduction on the modernized circuits, and the Lateral Reclosing Deployment projects are estimated to provide a 21% outage reduction on the modernized circuits. All projects included in this measure have a BCR of at least 0.9. As discussed in the 1898 & Co. analysis, the program contemplates various alternatives around the level of segmentation (customer pod size). During development of the program, the alternatives were evaluated, and the best configuration was selected for each feeder. Section 4.2.2.1 of the 1898 & Co. report describes this approach in more detail.

The other alternatives that SPS considered were: (1) maintaining the current pace of investment through the existing FLISR program and (2) establishing secondary feeds by installing new feeders or substations. The FLISR program provides substantial benefits to customers, but it does so in a more targeted manner, on a longer timeline, and without the comprehensive review and additional benefits—such as pod-size optimization—that are part of this measure. Establishing new substations and/or feeder ties would provide comparable resiliency benefits in some cases, but at a significantly greater cost. Installing

reclosers to sectionalize the distribution system is more cost-effective and provides greater operational flexibility.

Q. Why is SPS proposing projects with BCRs between 0.9 and 1.0 in the Distribution System Protection Modernization measure?

A. As explained in the 1898 & Co. report, investments with a BCR between 0.9 and 1.0 are cost-justified based on qualitative benefits such as mitigating general safety risks. This measure mitigates wildfire ignition risks and general safety risks. Thus, projects with a BCR between 0.9 and 1.0 are cost-justified in their own right and will also advance SPS's long-term resiliency objectives of modernizing protection systems and mitigating wildfire risks.

Q. What is the scope of SPS's proposed investment under the Distribution System Protection Modernization measure?

A. SPS will modernize approximately 150 mainline circuits and 60 laterals under this measure. The scopes for individual investment activities within each program are detailed in the following sections.

Q. What are the estimated costs for the Distribution System Protection Modernization measure?

A. SPS estimates approximately $92.3 million in capital costs for the Distribution System Protection Modernization measure. This includes $90.1 million for the Mainline Automated Reclosing Deployment program and approximately $2.1 million for the Lateral Reclosing Deployment program.

Q. Can you provide an example of a project included in the Plan?

A. Yes. The project I mentioned above as an example of the Distribution Overhead Hardening measure involves one protection zone on the feeder BURN1398. SPS will upgrade that entire feeder under this measure. The entire feeder serves 75 customers and spans 40 miles of primary line. SPS will add three midpoint reclosers, replace one recloser, and add one tie recloser, creating a post-investment pod size of 15 customers, compared with a pod size of approximately 37 customers today. The breakers and relays on this circuit are already upgraded to the current standard and are communications-enabled, so they will not be replaced. SPS will also replace 62 lateral fuses with non-expulsion alternatives and install 10 fault indicators through this project. The estimated cost for this investment is approximately $530,000, and the 1898 & Co. analysis estimates the customer benefit at approximately $8.8 million, including avoided restoration costs that are shared by all customers on the SPS system. The resulting BCR for this project is 20.5. The BCRs for projects in this measure range from 0.9 to 54.4, with an average BCR of 4.2.

A. Mainline Automated Reclosing Deployment

Q. Please describe the Mainline Automated Reclosing Deployment program.

A. As discussed above, the Distribution System Protection Modernization measure is designed to review and modernize the protection schemes and bring devices into SPS's ADMS. Communications with ADMS are required to remotely monitor line conditions and remotely control line equipment. This program specifically focuses on the distribution mainline. Mainline circuits are distribution circuits for which a substation breaker or a recloser is the primary protective device.

Under this program, SPS will install reclosers at strategic locations on mainline circuits to enhance sectionalization and load transfer capabilities. Communications upgrades will be performed as necessary to enable remote control of device settings, which will allow SPS to operate in EPSS and disable automatic reclosing based on weather/wildfire conditions or when SPS personnel are working on the line. SPS will also upgrade substation equipment to fully enable the automation and communications capabilities of the upgraded protective devices.

Additionally, in areas of heightened wildfire risk, SPS will replace tap-level fuses with non-expulsion alternatives and install fault indicators where appropriate to reduce patrol times following the system being placed in EPSS.

Q. What substation upgrades will be performed under this program?

A. SPS will replace substation circuit breakers, including tie breakers within the substation and feeder breakers that protect downstream distribution lines, with modern vacuum breakers. Vacuum breakers are magnetically actuated and contain fewer moving parts than legacy breakers, reducing the opportunities for failure. SPS will also replace legacy electro-mechanical relays with modern, microprocessor-based relays to fully enable the automation capabilities of communications-enabled reclosers.

Q. What is the scope of SPS's proposed investment under this program?

A. SPS will modernize approximately 150 circuits under this program, including upgrading, replacing, or installing approximately 680 reclosers, 30 new communications devices, 965 fault indicators, and 2,570 fuses. Additionally, SPS will replace approximately 65 relays and 16 breakers at substations.

Q. How will SPS prioritize facilities for upgrades under this program?

A. Consistent with SPS's prioritization framework, SPS will prioritize facilities for upgrades based on the wildfire risk in the area and BCR value. Under SPS's current standard, SPS normally expects that a minimum of one recloser will be needed every 10 circuit miles of line; however, this program may result in more or less frequent reclosers as needed to optimize protection schemes for sectionalization. The protection studies performed under this measure will help SPS select the optimal locations to install reclosers.

As SPS is modernizing the protection schemes, all tie reclosers will be installed with or upgraded to include communications capabilities. Substation upgrades will target the stations that directly serve the upgraded protection schemes. In areas of heightened wildfire risk, SPS will replace fuses and arrestors and install wildfire fault indicators as needed. For purposes of this program, if any asset in a protection zone is in an area of heightened wildfire risk, SPS will replace/install fuses, arrestors, and fault indicators across the entire protection zone.

B. Lateral Reclosing Deployment

Q. Please describe the Lateral Reclosing Deployment program.

A. Like the Mainline Automated Reclosing Deployment program, the Lateral Reclosing Deployment program involves installing reclosers at strategic locations on the SPS system to enhance sectionalization. However, under the Lateral Reclosing Deployment program, SPS will install reclosers on lateral circuits (*i.e.*, circuits that would be typically protected by a fuse) that do not reside in areas of heightened wildfire risk. This is because these devices will not remotely

communicate with the control center and, as such, cannot be brought out of reclosing settings remotely. In times of heightened wildfire risk, this is a critical feature to mitigate ignition risks.

Q. What upgrades will be performed under this program?

A. SPS will install new reclosers on lateral circuits to further sectionalize the system. This limits the impact of a fault to a smaller set of customers than are protected by the Mainline Automated Reclosing Deployment program.

Q. What is the scope of SPS's proposed investment under this program?

A. SPS will add protective devices at approximately 60 taps and install approximately 170 reclosing devices under this program.

Q. How will SPS prioritize facilities for upgrades under this program?

A. Since this program will be deployed in areas with lower wildfire risk, SPS will prioritize investments based on their BCR values. All potential lateral reclosing projects with BCR of 0.9 or higher are included in the Plan.

VII. OPERATIONAL FLEXIBILITY

Q. Please describe the Operational Flexibility measure.

A. Under the Operational Flexibility measure, SPS will (1) procure additional mobile substation equipment and (2) install additional switching devices on targeted transmission facilities.

Q. What resiliency methods does the Operational Flexibility measure employ?

A. The Operational Flexibility measure uses the hardening electric transmission and distribution facilities method and the modernizing electric transmission and

distribution facilities method, as described in 16 TAC § 25.62(c)(1)(A) and (B), respectively.

Q. What are the resiliency events and risks the Operational Flexibility measure is designed to address?

A. The Operational Flexibility measure will address risks posed by wind, flood, tornado, winter, heat, and cold events.

Q. How will the Operational Flexibility measure allow the SPS system to prevent, withstand, mitigate, or more promptly recover from the risks posed by resiliency events?

A. Mobile substation equipment can be transported to a station when a resiliency event results in overloading or damage to a substation transformer. This allows SPS to mitigate and more promptly recover from resiliency events by quickly and efficiently restoring service to customers. When the load from the damaged transformer cannot be transferred to another feeder or substation transformer, mobile substation equipment is often the only option to restore service while a permanent repair or replacement is completed.

The Installation of Transmission Switches program will allow SPS to prevent, withstand, mitigate, and more promptly recover from outages caused by resiliency events by installing switches on the transmission system. Installing switching devices on the transmission system will enable sectionalization, fault isolation, and quick restoration of service when a fault occurs on SPS's transmission facilities.

Q. How will SPS customers benefit from the Operational Flexibility measure?

A. Additional mobile substation equipment will allow the SPS system to more promptly recover from resiliency events that damage or destroy substation transformers. Much of SPS's system serves multiple small communities with significant distances between them, where the number of customers does not justify two substations, multiple substation transformers, or field ties. In those locations, mobile substation equipment is a cost-effective solution to maintain continuity of service and keep customer costs low during substation equipment failures.

The addition of transmission switches will reduce the need to deploy SPS personnel to manually sectionalize faults on the transmission system, reducing restoration costs. These programs will result in customers experiencing fewer outages and will often result in faster restoration times when outages occur.

Q. Why did SPS select these programs over any reasonable and readily identifiable alternatives?

A. As described above, sectionalizing the distribution system is an alternative to mobile substation equipment that can prevent or shorten outages on parts of the system with adequate feeder ties and capacity. However, if a transformer outage cannot be addressed with a load transfer, the only alternatives to deploying mobile substation equipment are to deploy mobile generators, if permitted by statute, or wait for a permanent repair or replacement to be completed. Deploying mobile substation equipment is typically the fastest, most reliable, and most cost-effective alternative.

There are virtually no alternatives to the Installation of Transmission Switches program. In situations where transmission switching is needed and a

switch does not exist, the only alternative is to deploy field resources to perform manual disconnections. This work is often performed "hot," meaning SPS personnel must physically contact an energized line. The additional switches proposed in this program will allow for faster switching compared with the manual alternative, reducing restoration times for customers, while also reducing the need for "hot" work. Thus, this program will provide resiliency benefits and general safety benefits for SPS customers and personnel.

Q. What is the scope of SPS's proposed investment under the Operational Flexibility measure?

A. SPS will procure six mobile substations, one mobile circuit switcher, and one mobile regulator under the Mobile Substation Equipment Procurement program. SPS will install 17 switching devices under the Installation of Transmission Switches program.

Q. What are the estimated costs for the Operational Flexibility measure?

A. The estimated costs for the measure as a whole are approximately $43.7 million. This includes approximately $30.8 million in capital investment for the Mobile Substation Equipment Procurement program and approximately $12.8 million for the Installation of Transmission Switches program. SPS also expects to incur about $6,000 in incremental O&M expense under the Installation of Transmission Switches program.

A. Mobile Substation Equipment Procurement

Q. What mobile substation equipment does SPS currently own?

A. SPS currently owns 12 mobile substations with 4 more on order to be delivered in 2025, which will allow SPS to retire aging units and better support the existing fleet. The units to be procured through this program are incremental to the existing and planned units.

Q. How will SPS use the additional mobile substation equipment to improve its response to resiliency events?

A. Additional mobile substation equipment will provide outage support to improve SPS's response to resiliency events. The equipment can be deployed and connected at a substation to temporarily restore service while permanent repairs are completed. Given the size of SPS's service area, the availability of additional mobile substation equipment will also allow SPS to provide planned outage support to an increased number of substation projects with minimal service interruption to customers, while still being able to quickly respond to emergency restoration efforts. SPS currently deploys sufficient mobile substation equipment for full substation restoration within an 18–24-hour timeframe. The additional inventory proposed in the SRP will strengthen SPS's ability to respond to emergency outages while also supporting the additional work proposed under the SRP.

Q. Can you give an example of how SPS has used mobile substation equipment to more promptly recover from a resiliency event?

A. Yes. In June of 2023, the Texas Panhandle experienced one of the hottest days of the year. Many substations and feeders were at peak loading due to the increased

demand from air conditioning units. The transformer at SPS's Colter substation failed due to a combination of loading and equipment age, and SPS had limited ability to transfer the load because the surrounding feeders and substations were also fully loaded. SPS deployed, connected, and energized mobile substation equipment at the Colter substation, restoring service to customers in about 18 hours. That mobile substation equipment continued to serve the Colter substation for approximately 4 months while a permanent replacement was sourced and delivered. This example illustrates how SPS utilizes the mobile substation fleet to restore service to customers quickly. It also highlights the amount of time a single mobile substation can deployed to one location, as well as the length of time customers could be without service in the absence of a sufficient stock of mobile substation equipment. Along with the increasingly long lead times for replacement transformers, the long duration of deployments is one reason SPS is seeking to acquire additional mobile substation equipment.

B. Installation of Transmission Switches

Q. What is SPS's current standard for installing switches on transmission facilities?

A. SPS's current switch installation work addresses: (1) the replacement of existing switches due to age or defect, and (2) the installation of switches on either side of a newly installed tap. Switch installations on either side of a tap allow SPS to sectionalize facilities, isolating the outage on one side of the tap and allowing the substation to remain energized from the other side of the tap.

Q. How is the Installation of Transmission Switches program different from SPS's existing switch installation work?

A. SPS's current switch installation work addresses only existing switches needing replacement due to age or defect and the installation of switches as part of installing a new tap. The Installation of Transmission Switches program will add new switches on existing transmission facilities that are not currently equipped with switches. This will allow for greater sectionalization and fault isolation on the transmission system to keep more customers energized in the event of a transmission line outage.

Q. How did SPS select locations to install transmission switches under this program?

A. SPS selected locations for new switch installations based on (1) existing switching capability at substation taps and (2) transmission line miles of exposure to outage. Switch installations will occur at substations that would not currently remain energized if the transmission feeder line were deenergized.

Q. How many transmission switches will SPS install under this program?

A. Under this program, SPS will install 17 transmission switches, including 14 loadbreak switches and 3 non-loadbreak switches.

Q. Will any additional work be required to install the transmission switches?

A. Line outages or temporary work will be required to install transmission switches. SPS will maintain service to its customers during this work with temporary shoo-fly line configurations or mobile substation equipment. These methods will allow

SPS to reroute power around the affected section of the transmission line, minimizing downtime.

VIII. CONCLUSION

Q. Please summarize your direct testimony.

A. In this SRP, SPS is proposing five measures that are designed to address the risks posed by the most frequent and impactful resiliency events to the SPS system. SPS coordinated with 1898 & Co., a third-party consultant with expertise in risk and resiliency modeling, to perform a BCA for three of the five proposed measures, which guided SPS's selection of potential investments for inclusion in the SRP. All five measures will provide benefits to SPS customers that exceed their costs, in the form of fewer outages, reduced restoration times, and avoided restoration costs, in addition to mitigating wildfire risks, general safety improvements, and improving overall reliability during and after a resiliency event. The Commission should approve all five measures proposed in the SRP at the full investment level requested by SPS.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF TEXAS)
)
COUNTY OF LUBBOCK)

BRIANNE R. JOLE, first being sworn on her oath, states:

I am the witness identified in the preceding testimony. I am over 18 years of age, of sound mind, and am capable of making this affidavit. I have read the testimony and the accompanying attachments and am familiar with the contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

Brianne Jole
BRIANNE R. JOLE

Subscribed and sworn to before me this 4th day of December 2024 by BRIANNE R. JOLE.

NOTARY PUBLIC STATE OF TEXAS
ELISE GETER
My Notary ID # 126123595
Expires October 6, 2026

Elise Geter
Notary Public, State of Texas

My Commission Expires: 10-6-2026

Brianne Jole, P.E.

EDUCATION AND CERTIFICATION

Texas Tech University, Bachelor of Science in Mechanical Engineering **May 2016**
Professional Engineer, Licensed in TX and NM **June 2021**
Lean Practitioner **October 2019**

WORK EXPERIENCE

Xcel Energy **Manager, Distribution System Planning and Strategy** **October 2023 – Present**

- Manage a team of employees to forecast system capacity needs, plan reliability projects, and address overall resilience of the distribution system
- Support regulatory filings and rate cases on planned distribution activities
- Coordinate with Transmission and Generation Planning to align forecasts and work plans
- Meet with customers to obtain development forecasts and integrate them into our system capacity assessment

Xcel Energy **Senior Engineer, Distribution Design** **May 2016 – October 2023**

- Supervise and design large internal projects, substation exits, and voltage conversions
- Meet and continue contact with customers to determine distribution build out needed to provide service
- Work with scheduling and the construction department to ensure work is completed on time and efficiently
- Lead and engage during arcing demonstrations with young students to stress the importance of safety around electricity and allow them to better visualize circuits
- Listen and engage with employees on their concerns and challenges and identify solutions
- Restructure efforts to further goals while addressing pain points with current processes and tool that were previously implemented
- Identify, develop, and document current and future state processes and procedures
- Develop training and lead training sessions, managing all reactions and unprecedented questions
- Develop a range of communications and newsletters to communicate updates for continuous improvement
- Collaborate with Supply Chain to adjust project schedules based on material availability, identify future material needs

Xcel Energy **Engineering Intern, Distribution Design** **January 2015 - May 2016**

- Assisted full time engineers with distribution projects, corrected main line mapping database to reduce outage and design time, and assisted with reliability program to replace failing poles.
- Alleviated the workload for full time engineers by helping with repetitive tasks, completing small replacement jobs, and solving engineering problems as they arise.

Texas Roadhouse Lubbock **Waitress** **May 2013 – October 2019**

- In charge of welcoming guests, ensuring tables are adequately cleaned, taking food orders, and providing customers with a legendary experience while they are dining
- Address customer needs in a timely manner, creating personal connections with each customer

COMMUNITY INVOLVEMENT

Texas Tech, Mechanical Engineering Advisory Board **October 2023 - Present**

- Collaborate with active engineering students on their studies in the Mechanical Engineering department.
- Lead curriculum and research committee to review current course offerings to ensure alignment with industry needs.
- Provide feedback to the department from students on course offerings, course expectations, and instructor quality
- Engage with student lead organizations to support their endeavors and distribute contributions from the Board

NSPE – Emerging Leaders Program **November 2022 - August 2023**

- Participate in facilitator-led sessions and collaborative sessions with mentors to enhance and develop leadership skills
- Create a 100-day plan at the end of the program to implement knowledge
- Join colleagues in the Emerging Leaders Program Alumni Community

Denver City Tamale Festival **December 2018 - 2019**

- Judge the commercial and individual competition for the yearly Tamale Festival that the City of Denver City hosts every year, continuing the relationship with our community partners

DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF A TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY
of
WENDALL A. REIMER

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

(Filename: Reimer_Direct_Testimony.docx; *Total Pages:* 25)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
CISA	Critical Infrastructure & Security Agency
Commission or PUCT	Public Utility Commission of Texas
FBI	Federal Bureau of Investigation
MPUC	Minnesota Public Utilities Commission
O&M	Operations and Maintenance
OPGW	Optical Ground Wire
OT	Operational Technology
pLTE	Private LTE
RTU	Remote Terminal Unit
SPS	Southwestern Public Service Company, a New Mexico corporation
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services

LIST OF ATTACHMENTS

Attachment	**Description**
WR-1	Map of Proposed pLTE Coverage (TX North) (*Filename:* pLTE_TX_North.pdf)
WR-2	Map of Proposed pLTE Coverage (TX South) (*Filename:* pLTE_TX_South.pdf)

DIRECT TESTIMONY
OF
WENDALL A. REIMER

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Wendall A. Reimer. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55014.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") and a wholly owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by Xcel Energy Services ("XES") as Director II (IT) - Application Delivery in Technology Services.

Q. Please briefly outline your responsibilities in that role.

A. My current responsibilities are focused on the design, delivery, and establishing run-state support for operational technology ("OT") networks supporting Xcel Energy's operations. This includes the deployment of private cellular ("pLTE") networks across the company, from design through run state, for each of Xcel Energy's operating companies. I also serve as a primary representative for the Technology Services and Security Business Area for Xcel Energy's operating companies.

Q. Please describe your educational background.

A. I graduated in 1981 from Concordia College, where I earned a bachelor's degree in business administration with minors in math and computer science and a series in accounting.

Q. Please describe your professional experience.

A. I joined Xcel Energy as an employee in 2014 and have 20 years of experience in the utility industry. I began working with Xcel Energy on a contract basis as a Program Manager in 2009, overseeing the deployment of significant network and telecommunication projects across all regions and facets of the company. Prior to working with Xcel Energy, I provided a variety of services to energy businesses, including the design and deployment of new technology at an energy company's new headquarters, development of new data centers and security solutions for energy companies, and multiple network and communications projects for non-utility organizations.

Q. What has your role been in the development of the SRP?

A. My team and I have planned, scoped, and created cost estimates for the Communication Modernization measure in the SRP. We provided this information to SPS and 1898 & Co., SPS's third-party consultant responsible for evaluating and modeling the costs and benefits of the proposed SRP investments. Additionally, we coordinated with SPS personnel and 1898 & Co. to integrate the Communication Modernization measure into the SRP.

Q. What will your role be in implementing the SRP if it is approved?

A. Following approval of the SRP, I will oversee SPS's implementation of the pLTE initiative that is part of the Communication Modernization measure. My team and

I will be responsible for ensuring the implementation plan is completed on time and within the estimated cost.

Q. Have you previously testified before any regulatory authorities?

A. Yes. I previously provided testimony before the Colorado Public Utilities Commission and the Minnesota Public Utilities Commission ("MPUC"), where I testified in support of advanced grid initiatives and OT network programs deployed in those states. I also provided testimony to the MPUC on behalf of Northern States Power Company's Technology Services group in the 2020 Minnesota electric rate case.

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to introduce and support the Communication Modernization measure proposed in SPS's SRP. I describe the Communication Modernization measure, including the activities, facilities, and equipment involved; the proposed scope and estimated costs of SPS's investment; the expected benefits for SPS customers; and SPS's systematic plan to implement the measure. I explain how investing in a private communications network will secure SPS's system against cybersecurity threats while unlocking the benefits of SPS's proposed Distribution System Protection Modernization measure. And I explain how the two measures work in conjunction with one another to make the SPS system more resilient against weather-based resiliency events and to mitigate the risk of SPS assets causing a catastrophic ignition event. Finally, I explain why the Communication Modernization measure is the best option to meet these objectives.

Q. Please summarize your direct testimony.

A. The Communication Modernization measure consists of investments in communications infrastructure to build out a pLTE network, add new optical ground wire ("OPGW") to SPS's private fiber network, and install remote terminal units ("RTUs") at SPS substations. These investments will vastly improve SPS's communications capabilities and make the SPS system more secure against cybersecurity resiliency risks. They will also allow SPS to remotely monitor and control hundreds of communications-enabled field devices across its system, which will benefit SPS customers by reducing outage durations, restoration costs, and wildfire ignition risks.

Today, SPS's ability to communicate with field devices on the distribution system relies on the availability of a public cellular network. Unfortunately, across much of SPS's service area, public networks do not provide adequate coverage to support these communications. Even where public networks are available, they present significant security risks for electric utilities. Recent cyber-attacks targeting both public cellular networks and public utility systems underscore the need for electric utilities to make their communication systems more secure.

The Communication Modernization measure will address these risks by rapidly advancing the buildout of SPS's pLTE and private fiber networks. SPS will migrate OT communications to the private network, where they will be protected by a robust cybersecurity framework. SPS will maintain access to public cellular networks for backup communications and will also use the expanded private fiber network for data transport (*i.e.*, "backhaul") between the pLTE network and SPS's Advanced Distribution Management System ("ADMS").

The Communication Modernization measure provides three benefit streams to SPS customers. First, it protects against cyber-attacks targeting SPS communications and operations. Second, it mitigates the impacts of weather-based resiliency events and wildfires by enabling remote monitoring and control of protective devices across the SPS system. Finally, it creates a third layer of redundancy for SPS's communication systems to ensure no single event can cause a network outage.

Q. What is your recommendation regarding the SRP?

A. I recommend that the Public Utility Commission of Texas ("Commission") approve SPS's proposed investments under the Communication Modernization measure. Approving these investments will make the SPS system more resilient against weather-based resiliency events, more secure against cybersecurity threats, and less likely to cause an ignition event.

III. COMMUNICATION MODERNIZATION

Q. Please describe the Communication Modernization measure.

A. Under the Communication Modernization measure, SPS will make its electric system more resilient by building private communications infrastructure to extend pLTE and private fiber networks across its service area. These investments will strengthen SPS's cybersecurity and enable remote monitoring and control of field devices on the distribution system. SPS will build 49 new cellular towers at existing SPS substations and microwave installations and migrate its OT communications to the pLTE network. Additionally, SPS will install four RTUs to provide remote control capabilities at substations where pLTE towers will be installed. Finally,

SPS will install 83 miles of new OPGW to connect the new RTUs to SPS's private fiber network and provide backhaul for the pLTE network.

Q. What resiliency methods does the Communication Modernization measure utilize?

A. The Communication Modernization measure uses the modernizing electric transmission and distribution facilities, information technology, and cybersecurity resiliency methods, as described in 16 Texas Administrative Code ("TAC") § 25.62(c)(1)(B), (F), and (G), respectively.

Q. Please describe the field devices that will connect to the pLTE network.

A. The field devices that I primarily discuss in my testimony are the communications-enabled protective relays, breakers, and reclosers that SPS proposes to deploy under the Mainline Automated Recloser Deployment program. However, numerous other devices can connect to the pLTE network, giving SPS additional options to improve service and provide value to its customers. SPS's Advanced Metering System that the Commission approved in 2022 is one example.

Q. How does SPS currently handle OT communications?

A. SPS control systems currently connect to field devices on distribution circuits through a Field Area Network that uses public cellular networks where they are available. SPS has also been deploying private OPGW and microwave installations for many years and continues to invest in these solutions. OPGW connects RTUs at transmission and distribution substations to SPS's private fiber network and ADMS, giving SPS greater visibility and control of critical substation equipment. SPS installs OPGW on transmission lines during new construction or during maintenance on existing transmission lines. SPS's microwave installations provide

long-distance, point-to-point data transmission between SPS facilities and control systems.

Q. Why is the pLTE network a priority for SPS?

A. Building out the pLTE network is integral to SPS's long-term resiliency objectives of modernizing protection systems and mitigating wildfire risks. Migrating OT communications to a pLTE network will modernize SPS's communications, increase communications availability, provide greater visibility into the state of the system, enable remote monitoring and control of connected devices, and give SPS greater control over network security and reliability. For example, as explained in the 1898 & Co. report and the direct testimony of SPS witness Brianne Jole, under the Distribution System Protection Modernization measure, SPS will deploy hundreds of communications-enabled reclosers, breakers, and protective relays to enable automated switching and load transfer, remote monitoring of system conditions, and remote control of devices. This includes the ability to remotely change relay settings in response to system conditions virtually instantaneously. These capabilities are critical to SPS's efforts protect its system and customers against resiliency risks, including wildfire ignition risks. And they will be less effective without the pLTE network proposed in the Communication Modernization measure.

Q. Why can SPS not use public cellular networks for OT communications?

A. SPS uses public cellular networks where they are available. This is currently the only option to facilitate communications between field devices on the distribution system and SPS control systems, meaning SPS can only deploy these devices in areas with public cellular coverage. SPS's Texas service area covers approximately

33,000 square miles of rural, sparsely populated land in the Texas Panhandle and Texas South Plains. Public cellular networks in this region rarely extend more than 5-10 miles from the nearest highway. Today, SPS cannot communicate with field devices outside the public carriers' network coverage without installing signal repeaters to extend the cellular signal to device locations. Even using a series of repeaters, SPS can only extend a signal about 15 miles. Given the size of SPS's service area, this severely restricts SPS's ability to effectively deploy communications-enabled protective devices.

Q. How will the Communication Modernization measure make the SPS system more resilient?

A. The pLTE network will make the SPS system more resilient by extending cellular coverage across SPS's service area, which will enable the widespread deployment of communications-enabled protective devices. The ability to remotely monitor and control these devices over the pLTE network will allow SPS to automate switching operations, change device settings in real time, and more precisely diagnose and locate faults on the distribution system, as described in more detail in Ms. Jole's direct testimony.

The pLTE network will also improve resiliency by creating an additional layer of connectivity over the public cellular networks, which will continue to provide backup service as needed. SPS's private fiber network will sit beneath these two, providing data backhaul between the pLTE network and ADMS. These three layers of connectivity each have a distinct primary use, and together they will help to ensure that no single event can disrupt communications between field devices and the SPS control center. Finally, deploying a pLTE network will make

the SPS system more resilient by enhancing the security of SPS's OT communications.

Q. How will a pLTE network make SPS's OT communications more secure?

A. On a public cellular network, SPS is completely reliant on a third-party provider to keep information secure and identify potential security issues. SPS's data traffic is not prioritized on the public network, and once it is sent to the provider, SPS loses control of that data until it is received by SPS's backend systems. When the public cellular provider experiences a network outage, security breach, or data loss, SPS cannot diagnose the issue, reroute/recover the data, or restore connectivity. In essence, SPS is at the mercy of third-party providers to respond in a thorough and timely manner.

Migrating communications from third-party networks to pLTE will reduce the number of attack vectors for intruders because only approved devices will have access to the network. SPS will implement industry-leading security standards and protocols to protect data traffic over the pLTE network, including end-to-end monitoring of all network traffic and user devices to quickly detect and respond to security threats. The pLTE network will also be a zero-trust environment, allowing SPS to implement additional security controls such as rogue device detection and Internet Protocol Security tunnels to encrypt and authenticate data traffic. SPS will implement and maintain data priority and restriction at the device level throughout the network, and end-device security will be enhanced through encryption and multi-factor authentication.

Q. Why is cybersecurity important to SPS today?

A. Enhancing cybersecurity is a top priority for SPS because our customers depend on us to power their daily lives. Cybersecurity threats pose an increasingly prevalent resiliency risk for electric utilities. In September, Reuters reported that cyber-attacks targeting U.S. utilities surged 70% in 2024.[1] This includes multiple attacks that caused operational issues for Texas public utilities serving over 2 million people. One such attack targeted utility systems in Hale Center and Muleshoe, Texas, both of which are in SPS's service area.[2] SPS's expansive and often remote critical infrastructure makes it an attractive target for bad actors, as evident from documented cybersecurity breaches like the Colonial Pipeline event in 2021. Just last month, the Federal Bureau of Investigation ("FBI") and Cybersecurity & Infrastructure Security Agency ("CISA") warned that state-sponsored hackers had infiltrated public cellular networks and other telecommunications infrastructure, placing user data at risk of interception or alteration.[3]

An attack targeting SPS's OT communications over a public cellular network could potentially disrupt service for thousands of SPS customers. While SPS has a robust cybersecurity framework, the inability to monitor or control data on the public network is a significant concern. This concern is increasingly driving public utility companies to invest in pLTE networks in recent years, including the

[1] *See Cyberattacks on US Utilities Surged 70% This Year, Says Check Point*, Reuters (Sep. 11, 2024), *available at*: https://www.reuters.com/technology/cybersecurity/cyberattacks-us-utilities-surged-70-this-year-says-check-point-2024-09-11/.

[2] *Rural Texas towns report cyberattacks that caused one water system to overflow*, Texas Tribune (Apr. 19, 2024), *available at:* https://www.texastribune.org/2024/04/19/texas-cyberattacks-russia/.

[3] *Joint Statement from FBI and CISA on the People's Republic of China (PRC) Targeting of Commercial Telecommunications Infrastructure* (Nov. 4, 2024), *available at*: https://www.cisa.gov/news-events/news/joint-statement-fbi-and-cisa-peoples-republic-china-prc-targeting-commercial-telecommunications.

Lower Colorado River Authority, Southern Company, Evergy, Southern California Edison, and Hawaiian Electric, among others.

Q. What are the resiliency events and risks the Communication Modernization measure is designed to address?

A. As described above, this measure will directly address risks from cybersecurity threats by providing SPS with substantially more control over network access, connectivity, and data traffic. Additionally, this measure will fully enable the benefits of the Distribution Protection System Modernization measure by providing the network availability needed to remotely monitor and control protective devices across the SPS system. Therefore, this measure also addresses risks associated with weather-based resiliency events and wildfires.

Q. How will the Communication Modernization measure allow the SPS system to prevent, withstand, mitigate, or more promptly recover from weather-based resiliency risks and wildfires?

A. The expanded private networks will connect distribution field devices to SPS's ADMS. Resilient two-way communications to all critical devices that tie directly into SPS control systems will provide faster and more complete situational awareness, as well as the ability to instantaneously implement control measures to minimize the impacts of resiliency events.

As described in section III (B) of the SRP, SPS operates in fire-prone areas of Texas. These areas often have limited public cellular coverage. During fire weather conditions, SPS currently must dispatch personnel to manually disable automatic reclosing and activate enhanced powerline safety settings on protective devices to mitigate wildfire risks. This process can take hours to complete, and that

time increases with every additional device that must be adjusted. With the pLTE network in place, SPS can remotely adjust device settings in a matter of minutes after fire conditions are identified. This will significantly limit the likelihood of SPS facilities igniting a catastrophic wildfire.

Q. How will SPS customers benefit from the Communication Modernization measure?

A. SPS customers will benefit from a more resilient, more secure electric system. Migrating SPS's OT communications to a pLTE network will make the network more secure, allowing SPS to prevent, withstand, mitigate, or more promptly recover from risks posed by cybersecurity threats that could cause outages, data breaches, or other system issues. The pLTE network will also facilitate communications with hundreds of protective devices across the SPS service area, including in areas not covered by a public cellular network. This is particularly important for SPS given the size and rural nature of its service territory.

With a robust pLTE network, SPS can remotely sectionalize the distribution system and automate load transfers, giving SPS greater operational flexibility and situational awareness to prevent, withstand, mitigate, and more promptly recover from risks posed by weather-based resiliency events and wildfires, as described in more detail in Ms. Jole's direct testimony. These capabilities will ultimately reduce the frequency and duration of customer outages, reduce system restoration costs, and significantly aid SPS in addressing wildfire risks, including the risk of SPS facilities causing an ignition.

Q. Is SPS providing evidence that the Communications Modernization measure will be effective at providing these benefits to customers?

A. Yes. SPS engaged 1898 & Co, an independent consultant with expertise in risk and resiliency modeling, to perform a benefit-cost analysis ("BCA") of certain measures proposed in its SRP, including the Communication Modernization measure. 1898 & Co. performed a combined BCA for the Mainline Automated Reclosing Deployment program and the Communication Modernization measure, which estimated a combined benefit-cost ratio ("BCR") of 1.8. In other words, the benefits customers will enjoy from SPS's proposed investments in modernizing its communications and protection systems are almost double the estimated costs. Further, 1898 & Co.'s analysis did evaluate the cybersecurity or wildfire benefits of the Communication Modernization measure, meaning the BCR of 1.8 actually understates the true benefits of the measure.

Q. What evaluation metrics is SPS proposing to measure the effectiveness of the Communication Modernization measure?

A. The metrics SPS proposes to evaluate the effectiveness of this measure include: (1) identification of underperforming areas; (2) average duration of outage events; (3) average storm restoration durations; (4) completion of cellular tower construction; and (5) connectivity of end devices on the cellular network.

Q. Why are these metrics appropriate for evaluating the effectiveness of the Communication Modernization measure?

A. Tracking the completion of cellular towers and connectivity of end devices will objectively measure SPS's implementation of the Communication Modernization measure and related activities. The remaining metrics will provide data to evaluate

whether the added connectivity is reducing the impacts of resiliency events for SPS customers, which is the ultimate goal of this measure.

Q. Are there other benefits for customers from SPS's pLTE network?

A. Yes. Deploying a pLTE network will reduce and avoid additional operations and maintenance ("O&M") expenses. To maintain access to the public cellular network, SPS must pay a monthly fee for each connected device, which is recorded as an O&M expense. Once a geographical area is covered by pLTE there is no additional cost to SPS or its customers to add additional devices to the network.

Q. Could SPS use the private OPGW network to communicate with distribution field devices?

A. No. Extending OPGW to distribution field devices is generally cost-prohibitive due to the need to physically run fiber to each connected device. Extending OPGW to field devices outside the substation termination point also adds security risks. Additionally, the maintenance and replacement costs for that much additional fiber would be considerable.

Q. Does SPS have existing plans or programs to build out its private communications networks?

A. SPS is currently deploying pLTE near Lubbock and Amarillo and will have one tower operating in each of these areas by 2026. The 49 towers proposed in the Communication Modernization measure are in addition to these two installations.

Additionally, SPS plans to invest approximately $130 million to extend its private fiber network over the next few years. The OPGW proposed in this SRP is

incremental to SPS's already planned work. SPS does not have an existing program to expand RTU deployment.

Q. How are the activities in this measure distinct from SPS's existing programs?

A. The two towers near Lubbock and Amarillo are the only pLTE installations currently planned. Any new installations outside of those proposed in the SRP would not materialize until 2029 or later. The Communication Modernization measure will substantially advance this deployment. If approved, SPS will establish a pLTE network that covers most of its distribution system, including in areas of heightened wildfire risk, within the next three to four years.

Q. How did SPS select locations for the pLTE towers proposed in the SRP?

A. SPS selected locations for pLTE towers after performing cellular propagation studies to optimize coverage areas, with a focus on maximizing network coverage in areas of heightened wildfire risk.

Q. Where will the proposed pLTE towers be located?

A. Attachments WR-1 and WR-2 to my direct testimony are maps depicting the planned locations and coverages of the proposed pLTE towers. SPS's distribution feeders are shown on these maps as a green line. Any SPS facility within the areas shaded blue or purple on these maps will be able to fully utilize SPS's pLTE network. Each pLTE tower will be built at an existing SPS-owned substation or microwave communication site and will reside behind a physical security perimeter. These locations already have, or will have, OPGW or microwave to support data backhaul.

Q. What is the scope of SPS's proposed investment under the Communication Modernization measure?

A. SPS will install 49 pLTE towers, four RTUs, and approximately 83 miles of private OPGW, including six OPGW-RTU terminations.

Q. How will SPS implement the Communication Modernization measure?

A. SPS has already acquired rights to the 900 MHz broadband spectrum that it will use for the pLTE network. SPS will build the new towers, add new OPGW on existing transmission facilities, and install the new RTUs between 2026 and 2028. The table below summarizes the planned scope of work for each year of the implementation.

Table 1 - Communication Modernization Implementation

	2025	2026	2027	2028	Total
pLTE Towers	0	16	15	18	49
OPGW Line Miles	0	7	44	32	83
OPGW Terminations	0	2	2	2	6
RTUs	0	1	2	1	4

Q. What are the estimated costs for the Communication Modernization measure?

A. The table below summarizes the estimated costs for the Communication Modernization measure, broken down by activity and year.

Table 2 - Communication Modernization Budget					
	2025*	**2026**	**2027**	**2028**	**Total**
PLTE Towers	$0	$31.90M	$28.80M	$35.41M	$96.11M
OPGW Line Miles	$0	$0.52M	$0.54M	$0.55M	$1.61M
OPGW Terminations	$0	$0.92M	$5.89M	$4.50M	$11.31M
RTUs	$0	$0.89M	$1.83M	$0.94M	$3.66M
Total Capital	$0	$34.24M	$37.05M	$41.40M	$112.68M

*SPS currently does not plan to incur any costs for this measure in 2025 but may begin initial engineering for the pLTE towers in late 2025, depending on the timing of the Commission's decision on this SRP.

Q. Why did SPS select the deployment of a pLTE network over any reasonable and readily identifiable alternatives?

A. There are few alternatives to establish connectivity to field devices in areas that do not have public cellular coverage, and the monthly costs associated with public cellular connectivity where it is available can be cost-prohibitive. Installing repeaters to extend public cellular networks is not scalable given the sparsity of public network coverage and the size of SPS's service area. Nor is public cellular a secure alternative compared with a pLTE network protected by SPS's end-to-end security protocols.

SPS also considered partnering with public cellular providers for alternative solutions, but their solutions are still evolving and focus on usage/data plans, resulting in high O&M costs.

Q. Are there any reasonable and readily identifiable alternatives to installing OPGW and RTUs to build out SPS's private fiber network?

A. The only viable alternative to installing RTUs requires a cellular modem for each relay. Installing modems in place of RTUs would fail to capitalize on the OPGW backhaul already in place. It is also not financially viable in the long term and remains subject to the availability of a public cellular network. Without an RTU, SPS would have limited visibility into the substation. There are no viable alternatives to OPGW backhaul.

Q. Will the Communication Modernization measure require an outage on the transmission system to implement?

A. Building pLTE towers and installing RTUs will not require a transmission outage, but installing OPGW may require a transmission outage. If an outage is required, SPS will coordinate the outage with the Southwest Power Pool.

IV. SUMMARY AND CONCLUSION

Q. Please summarize your direct testimony.

A. Under the Communication Modernization measure, SPS will install 49 pLTE towers to make a private cellular network available across its service area. SPS will also install 83 miles of OPGW on existing transmission lines and 4 RTUs at existing substations to provide data backhaul for the pLTE network and give SPS greater visibility into its substation operations.

The pLTE network will allow SPS to remotely monitor and control the communications-enabled protective devices installed under the Distribution System Protection Modernization measure. These capabilities will mitigate wildfire risks and make the SPS system more resilient against weather-based

resiliency risks. Unlike the public cellular networks utilized today, the pLTE network will be protected by SPS's robust cybersecurity framework, making the SPS system more secure and more resilient against cybersecurity risks. The quantified and qualitative benefits of the Communication Modernization measure far outweigh its costs. Commission approval of this measure will make the SPS system more secure and more resilient, reducing customer outages and system restoration costs and providing SPS customers with additional safety and security benefits.

Q. Does this conclude your direct testimony?

A. Yes.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF HENNEPIN)

WENDALL REIMER, first being sworn on his oath, states:

I am the witness identified in the preceding testimony. I am over 18 years of age, of sound mind, and am capable of making this affidavit. I have read the testimony and the accompanying attachments and am familiar with the contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

WENDALL REIMER

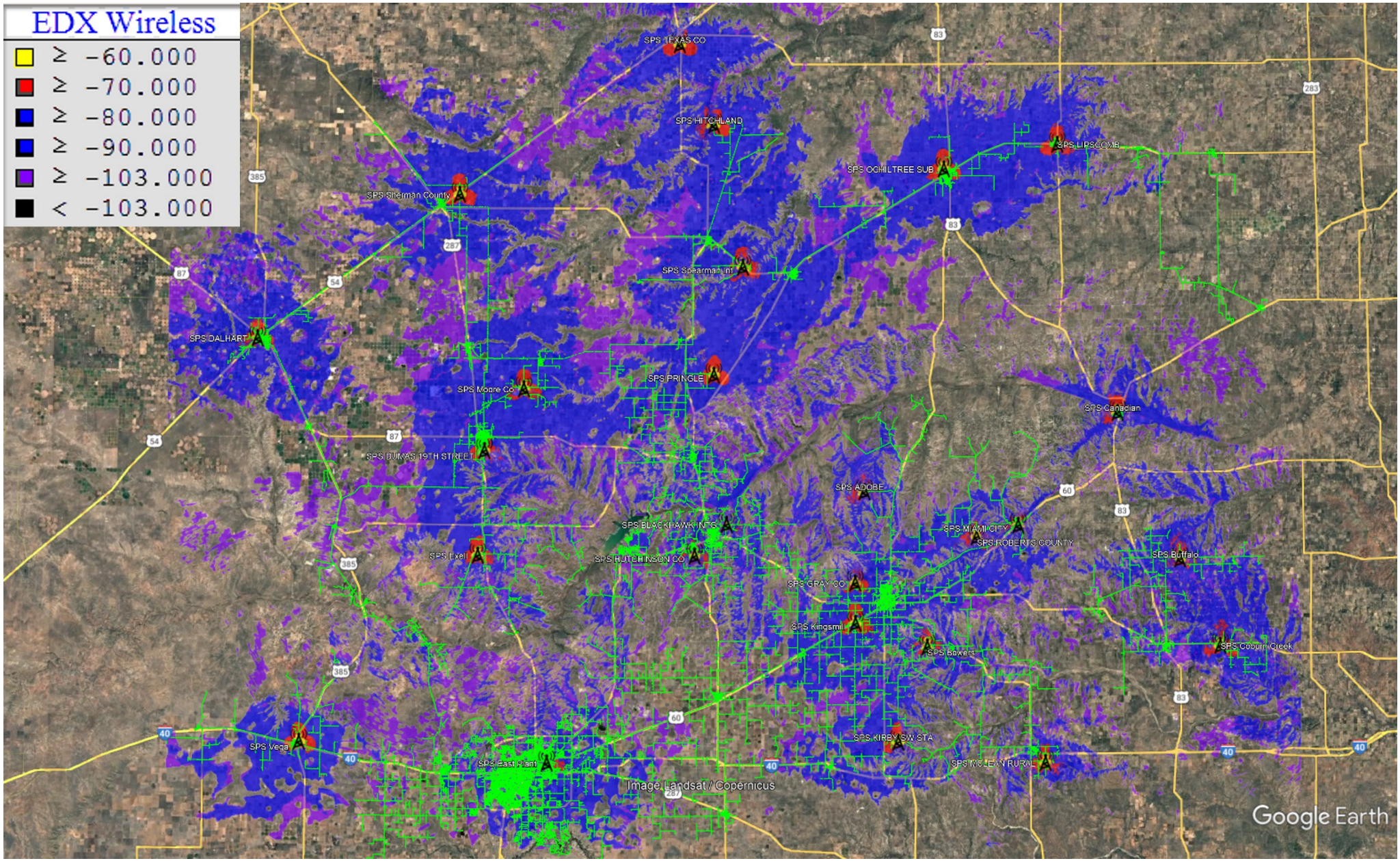
Subscribed and sworn to before me this 6th day of December 2024 by WENDALL REIMER.

Kaitlin Koenig
Notary Public, State of Minnesota

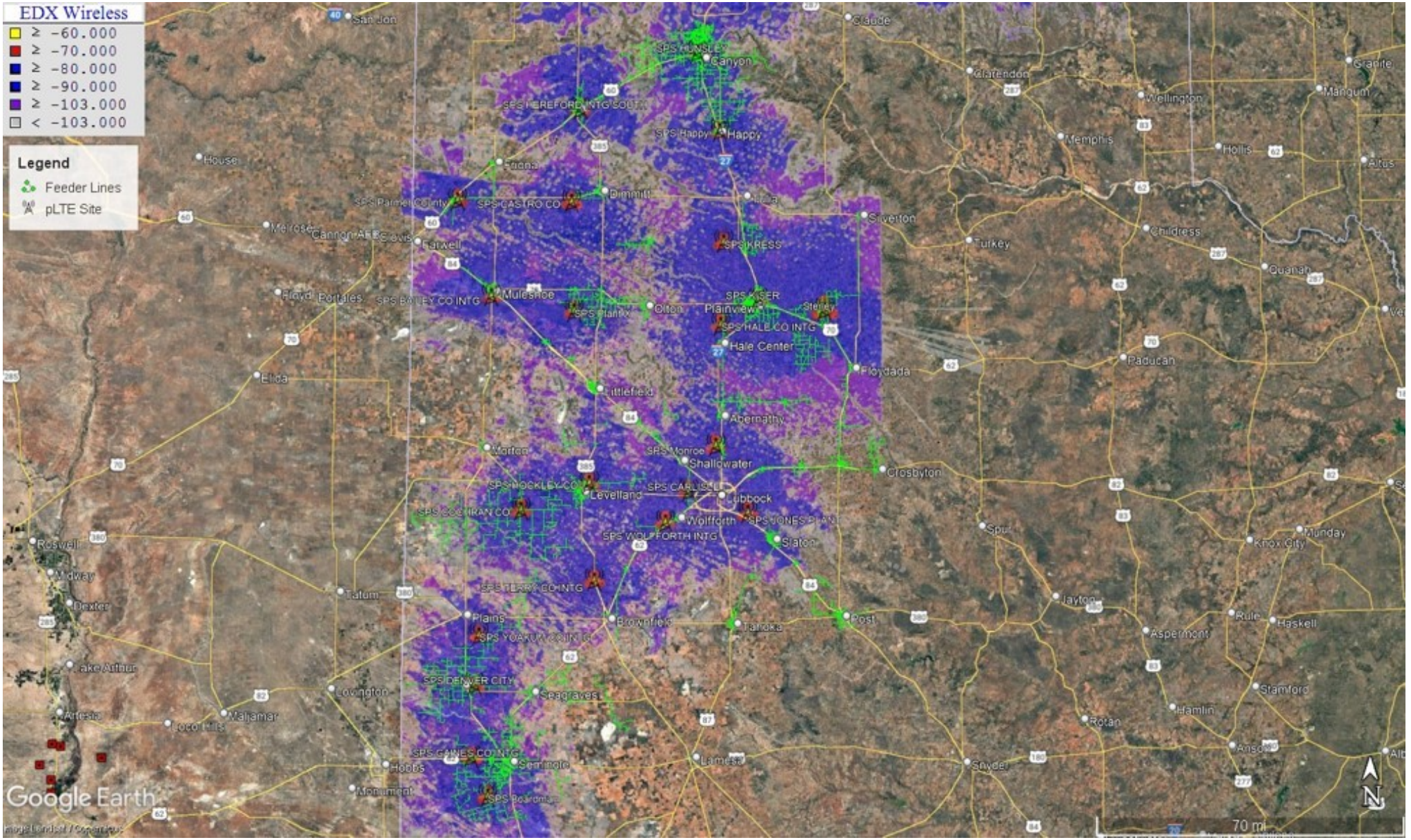
My Commission Expires: 1-31-2025

KAITLIN LEIGH KOENIG
Notary Public
State of Minnesota
My Commission Expires
January 31, 2025

SPS Texas North



SPS Texas South



DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§ § § § §**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY
of
JASON D. DE STIGTER

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

*(Filename: DeStigter*TXDirect.docx; *Total Pages:* 50)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CIS	Customer Information System
Commission or PUCT	Public Utility Commission of Texas
CMI	Customer Minutes Interrupted
DOE	Department of Energy
GIS	Geographic Information System
ICE	Interruption Cost Estimate
NOAA	National Oceanic and Atmospheric Administration
OMS	Outage Management System
Resilience Investment Study	SPS System Resilience Investment Study
SPS	Southwestern Public Service Company, a New Mexico corporation
SRP or Plan	System Resiliency Plan
TAC	Texas Administrative Code
Resiliency Rule	16 Texas Administrative Code § 25.62
T&D	Transmisson & Distribution
Xcel Energy	Xcel Energy Inc.

LIST OF ATTACHMENTS

Attachment	**Description**
JDD-1	Jason D. DeStigter Resume (*Filename:* DeStigter_Resume.pdf)
JDD-2	Integrated Resilience & Risk Investment Model (*Filename:* Resilience_Risk_Model.pdf)

DIRECT TESTIMONY
OF
JASON D. DE STIGTER

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Jason D. De Stigter. My business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying as a consultant on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") and a wholly owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by 1898 & Co. as the Director of Utility Investment Planning in our Utility Consulting Practice.

Q. Please generally describe the work of 1898 & Co.

A. 1898 & Co. was established in 2019 as the consulting division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell"). 1898 & Co. is a nationwide network of nearly 400 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution ("T&D"), Transportation, and Water industries.

Burns & McDonnell was established in 1898 and serves multiple industries, including the electric power industry. Burns & McDonnell is a family of companies comprising more than 10,000 engineers, architects, construction professionals,

scientists, consultants, and entrepreneurs, with more than 40 offices across the country and throughout the world.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Engineering and a Bachelor's in Business Administration from Dordt College, now called Dordt University.

Q. Please describe your professional experience.

A. I am a registered Professional Engineer in the State of Kansas with 15 years experience providing consulting services to electric utilities. After receiving my undergraduate degrees, I worked as a Principal Consultant at Black & Veatch in their Asset Management Practice, where I performed risk and resilience studies.

After leaving Black & Veatch, I joined Burns & McDonnell, and later, 1898 & Co. Through my work at 1898 & Co. and Burns & McDonnell, I have developed extensive experience in asset management, capital planning and optimization, risk/resilience assessments and analysis, asset failure analysis, and business-case development for electric utilities. I have been involved in numerous studies modeling risk for utility clients, including economic analyses for several multi-billion-dollar capital projects and large utility systems.

In my role as a Director of Utility Investment Planning, I have worked on and overseen risk and resilience consulting studies on a variety of electric T&D assets, including developing innovative risk and resilience analysis models. My primary responsibilities are business development, project delivery, and team development within the Utility Consulting Practice, with a focus on developing risk and resilience-based investment models for large capital projects/programs. I also supported four other Texas electric utilities in preparing their system resiliency

plans, performing resiliency investment analysis and planning, preparing resiliency investment reports, and testifying as an expert witness on their behalf.

Q. Have you testified before any regulatory authorities?

A. Yes. I previously provided pre-filed testimony in Public Utility Commission of Texas ("PUCT" or "Commission") Docket Nos. 56545, 56735, 56954, and 57057. I have also testified in numerous proceedings before regulatory authorities outside the State of Texas. With respect to resiliency investments outside of Texas, I have provided written and rebuttal testimony on behalf of Tampa Electric Company, Baltimore Gas & Electric, and Entergy Louisiana. My resume and a complete list of my testimony before regulatory authorities is provided as Attachment JDD-1 to my direct testimony.

II. EXECUTIVE SUMMARY

Q. Please provide a high-level summary of your direct testimony.

A. 1898 & Co. performed a comprehensive analysis of the resiliency investments SPS proposed in its System Resiliency Plan ("SRP" or "Plan"). This analysis uses historical weather data and data from various SPS systems as inputs into 1898 & Co.'s Integrated Resilience and Risk Investment Model. This model uses sophisticated data analytics and a series of sub-models to simulate historical resiliency events and likely future resiliency events, including their impacts to the SPS system under both Status Quo (*i.e.*, no additional resiliency investment) and Investment scenarios. The ultimate output of these models is the resilience and risk benefit-cost ratio ("BCR"), which compares the costs and economic benefits of a resiliency investment. Economic benefits are measured by monetizing the expected

Customer Minutes Interrupted ("CMI") and system restoration costs that the investment will avoid over its lifetime.

1898 & Co. performed a benefit cost analysis on three of SPS's SRP measures. As shown in the SPS System Resilience Investment Study ("Resilience Investment Study"), which is included as Attachment A to the Plan, there is significant opportunity to improve distribution system resiliency for SPS customers, with nearly $2 billion of potential investments with a BCR greater than or equal to 1.0. The $418.8 million of investment proposed in SPS's inaugural SRP that 1898 & Co. evaluated will provide quantified benefits to customers that far exceed their costs, with an average BCR of 3.4.

III. ASSIGNMENT AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. SPS engaged 1898 & Co. to assist with evaluating the impact of certain resiliency events on the SPS distribution system, determining the potential resiliency benefits of proposed resiliency measures and programs, demonstrating the net benefits to customers if those measures were implemented, and helping SPS to prioritize projects for the implementation of its SRP. My direct testimony introduces, summarizes, and incorporates by reference the Resilience Investment Study that 1898 & Co. developed as part of that effort. My direct testimony also explains the methodology 1898 & Co. used to conduct the evaluation. My direct testimony was

prepared by me or under my direction and supervision and is true and correct to the best of my knowledge.

The Resilience Investment Study provides a quantitative analysis of certain of SPS's proposed resiliency measures and programs based on a review of historical weather data and other relevant data sources. This analysis demonstrates that approximately $1.76 billion of potential resiliency investment on the SPS system is justified from a quantified benefit-cost perspective.

IV. RESILIENCE INVESTMENT STUDY INTRODUCTION

Q. Please describe your involvement in the development of the Resilience Investment Study.

A. I served as the 1898 & Co. project director for the Resilience Investment Study. In that role, I was directly involved in developing the resilience and risk-based benefits model, which 1898 & Co. used to identify resiliency investments, assess their effectiveness, calculate their expected costs and benefits, and assist SPS in determining which investments to propose in the SRP. I worked directly with SPS personnel to tailor 1898 & Co.'s resilience and risk-based planning approach to the unique characteristics of the SPS system and the requirements of 16 Texas Administrative Code ("TAC") § 25.62 ("Resiliency Rule"). I was also the primary author of the Resilience Investment Study, which provides quantitative and qualitative evidence of the effectiveness of SPS's proposed SRP investments.

Q. What were the objectives of the Resilience Investment Study?

A. The objectives of the Resilience Investment Study were to:

1. Quantify the resiliency improvement expected for individual resiliency investment activities, programs, and measures, specifically estimating the decrease in the duration and frequency of customer outages and reduction in outage-restoration costs;
2. Demonstrate the expected improvement in the number and duration of customer outages for certain measures within SPS's SRP; and
3. Identify investments with the highest quantified resilience and risk benefit per dollar invested into the system.

Q. How does the Resilience Investment Study achieve these objectives?

A. The Resilience Investment Study evaluated potential resiliency investments using 1898 & Co.'s proprietary Integrated Resilience and Risk Investment Model, which utilizes a resilience and risk-based planning approach to identify and analyze proposed resiliency investments on the SPS system. 1898 & Co. monetized the expected benefits for each applicable investment using the Department of Energy ("DOE") Interruption Cost Estimate ("ICE") Calculator and historical data provided by SPS, which allowed for an apples-to-apples comparison of the estimated costs and benefits of each investment activity. By conducting this analysis for each applicable measure and for individual protection zones across the SPS distribution system, 1898 & Co. created a report to aid SPS in determining the

expected effectiveness of resiliency measures and prioritizing specific, cost-effective investments that will maximize the value of the SRP to SPS customers.

Q. Did 1898 & Co. perform the same analysis for all of the resiliency measures included in SPS's SRP?

A. No. 1898 & Co. conducted the analysis described above for three of the measures in SPS's SRP: (1) Distribution Overhead Hardening, (2) Distribution System Protection Modernization, and (3) Communication Modernization. As explained below, 1898 & Co. did not conduct an analysis for the Wildfire Mitigation or Operational Flexibility measures.

Q. Did 1898 & Co. analyze the wildfire mitigation programs in the Resilience Investment Study?

A. No. This is not a service that 1898 & Co. currently provides. SPS witness Anne Sherwood discusses SPS's development of the Wildfire Mitigation measure, as well as the prioritization of other programs and measures in areas of heightened wildfire risk. I understand that SPS engaged EDM International, Inc. ("EDM") as a third-party consultant to assist with aspects of the Wildfire Mitigation measure. The direct testimony of SPS witness Ryan Brockbank, of EDM, addresses the consistency of the Wildfire Mitigation measure and SPS's Wildfire Mitigation Plan with leading-utility practices.

To be clear, 1898 & Co.'s analysis does not attempt to calculate the potential added benefit of the prevention or mitigation of wildfires from the application of

these programs, so any benefits from those programs would be in addition to those calculated in our analysis.

V. RESILIENCE AND RISK-BASED PLANNING APPROACH

Q. Please provide a brief overview of the resilience and risk-based planning approach that underlies the Integrated Resilience and Risk Investment Model.

A. 1898 & Co. used a resilience and risk-based planning approach to identify, prioritize, and perform a benefit-cost analysis ("BCA") for specific resiliency investment activities, programs, and measures. This approach incorporates historical data, sophisticated algorithms, and a suite of analytics models and planning modules to assess resiliency events, system vulnerabilities, and potential resilience investments. This analysis provided SPS with quantitative data to support the effectiveness of their proposed resiliency measures.

Benefits are estimated from a customer perspective and shown in terms of: (1) the decrease in the frequency and impact of customer outages caused by resiliency events, calculated as CMI; (2) monetization of the decrease in CMI utilizing the DOE ICE Calculator; and (3) decrease in restoration costs after resiliency events. The resilience and risk-based planning approach is rooted in a Resilience Conceptual Framework that is applied to estimate the expected resilience benefit of utility actions at the investment activity, program, substation, and measure levels.

Q. Please elaborate on the Resilience Conceptual Framework.

A. The resilience of a utility system is a function of many factors, but the two key factors are: (1) the resiliency events, or "stressors," to which the system is exposed,

including the type, frequency, and intensity of a given resiliency event and (2) the characteristics of the utility system itself, which determine the system's vulnerabilities when faced with a resiliency event. Examples of system characteristics that can cause vulnerabilities include vegetation density in proximity to utility facilities, whether facilities are located overhead or underground, the age and condition of equipment, and the extent to which the system can be sectionalized and remotely controlled, among others.

The Resilience Conceptual Framework can be applied to specific assets or facilities, a utility system as a whole, or the entire grid. It consists of three components. The first component is the stressor, or resiliency event. The stressor can be an external event such as high winds, ice storms, or extreme heat, to name a few. The second component is the "state of the system" when faced with the resiliency event. The state of the system, including any system vulnerabilities, measures the impact of the resiliency event from a customer's perspective, focusing primarily on the number and duration of customer outages and the cost to restore the system to a steady state. The third component consists of the utility's actions to prepare for, withstand, mitigate, respond to, and recover from the risks posed by the resiliency event. These can include actions taken immediately before a resiliency event, such as deploying personnel and equipment to strategic locations in anticipation of a storm, or actions taken well in advance of an event, such as making investments in grid-hardening and system protection.

An illustration of the Resilience Conceptual Framework is provided as Figure 1 below. This figure includes citations to the corresponding subsections of

the Resiliency Rule to highlight how the Resilience Conceptual Framework aligns with the Resiliency Rule's requirements.

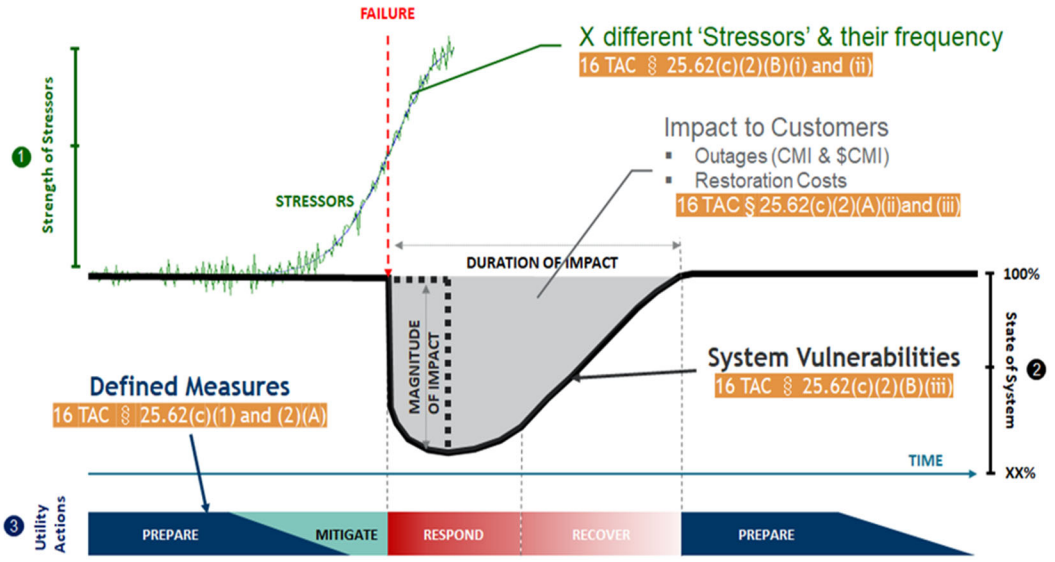


Figure 1: Resilience Conceptual Framework

Q. Which part of the Resilience Conceptual Framework is the focus of 1898 & Co.'s analysis?

A. 1898 & Co.'s analysis for SPS focuses on the 'respond and recover' phase for modeling the impacts of events and the 'preparation' phase for the proposed investments to prevent, withstand, mitigate, or more promptly recover from the risks posed by resiliency events.

Q. How was the Resilience Conceptual Framework applied within 1898 & Co.'s analysis?

A. The number and types of resiliency events that pose a risk to the SPS system vary across the SPS service area, as do the characteristics and vulnerabilities of the system itself. For example, the area of SPS's system around Amarillo has far more customers who would be impacted by a resiliency event; however, facilities in these

areas are more likely to have ties or loop designs that allow customers to receive service from an alternate source. The reverse is true for more rural areas of the SPS system, where fewer customers take service from a given facility, on average, and customers are more likely to be served from a radial feed. Finally, resiliency investments must often strike a balance between the desire to provide resiliency benefits to most SPS customers on one hand and the desire to make targeted investments to address specific vulnerabilities on the other.

In structuring the SRP, the 'preparation' phase of resilience, SPS and 1898 & Co. considered multiple factors in an effort to strike the appropriate balance between the benefits and costs of resiliency investments. These factors included (1) the different types of resiliency events that impact the system across the SPS service area; (2) the varying characteristics and vulnerabilities of the SPS system, such as in areas of heightened wildfire risk; and (3) the overall size of the Plan, with consideration for the costs for SPS customers. This balancing approach established the structure for the SRP, which is an integrated portfolio of measures designed to mitigate the impacts of the risks posed by the diverse set of resiliency events.

With the structure of the SRP established, 1898 & Co. utilized a resilience and risk-based planning approach to identify, prioritize, and perform benefit-cost modeling to support the development of the SRP within 1898 & Co.'s Integrated Resilience and Risk Investment Model. The model takes the "theory" of the Conceptual Resilience Framework and develops an actionable investment plan that prioritizes resilience and risk-based investments using available data, analytics models, and benefit-cost analyses.

VI. INTEGRATED RESILIENCE & RISK INVESTMENT MODEL

Q. Please describe the Integrated Resilience & Risk Investment Model.

A. The Integrated Resilience & Risk Investment Model employs a data-driven decision-making methodology using robust and sophisticated algorithms to calculate the resilience and risk benefits for each potential investment activity that makes up each measure. It uses a suite of modules, as well as data from the National Oceanic and Atmospheric Administration ("NOAA"), SPS, and other sources, to assess the expected costs and benefits of particular resiliency investments. The linkage between SPS equipment and the specific customers it serves is foundational to the model. Specifically, the model builds the direct linkage between each asset on the SPS system and the number and classes of customers that would be impacted if the asset were to fail. The model estimated the benefits for resilience investment activities from a customer-centric perspective including: (1) the decrease in utility restoration costs; and (2) the decrease in the number of customers impacted and the duration of the overall outage, calculated as CMI, which was then monetized using the DOE ICE Calculator. With these benefits, the model estimates the BCR for each investment activity, program, feeder, and measure. Based on these outputs, SPS was able to prioritize measures that will provide the greatest resiliency benefit when implemented in specific locations on the SPS system.

Q. What is the Resilience and Risk BCR?

A. The resilience and risk BCR is a single value that represents the modeling of a multitude of factors, including resiliency events, infrastructure vulnerabilities, infrastructure rebuild costs, and other economic factors, to provide a robust and

reliable measure to evaluate individual resiliency investments. The BCR value provides a quantified justification for resilience investment activities. This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for customers.

Q. How is the Integrated Resilience & Risk Investment Model structured?

A. The Integrated Resilience & Risk Investment Model begins with foundational data, including historical data from NOAA, which identifies the historical weather-based resiliency events that impacted the SPS system, and data from various SPS databases, which provides insight into SPS's existing facilities and historical outages on the SPS system. This information feeds the rest of the model.

The model includes three analytics sub-models: the Resilience Event Simulation Model, Outage Mitigation Resilience and Risk Mitigation Model, and Equipment Failure Resilience and Risk Mitigation Model. Each of these sub-models estimates the expected avoided costs and avoided customer outages associated with particular resiliency investments to identify the resilience and risk benefits of a resiliency measure. Together, they provide a direct link between historical resiliency events and outages on the SPS system with sufficient detail to estimate how future resiliency events will impact the system under different investment scenarios. In other words, these models allow for a quantitative analysis of how SPS's system responded to a historical resiliency event and how that same system would have responded (or will respond in the future) had certain resiliency investments been in place. This allows 1898 & Co. to objectively demonstrate how investments in a particular resiliency measure can improve the system's ability to

prevent, withstand, mitigate, or more promptly recover from the risks posed by a resiliency event.

Finally, the model includes a Plan Development Module that integrates the benefit-cost results from each of the analytics models, normalizes to avoid double-counting benefits, and captures SPS's execution approach. This module assists in the prioritization of resilience investment activities to aid SPS in developing an executable plan that balances the maximization of customer benefits with the anticipated resource and execution constraints for each measure and program. An illustration of the Integrated Resilience & Risk Investment Model is attached as Attachment JDD-2 to my direct testimony.

Q. Please provide additional details on the foundational data 1898 & Co. used in the Integrated Resilience & Risk Investment Model.

A. The Integrated Resilience & Risk Investment model primarily relied on historical NOAA weather data, operational data from SPS's Outage Management System ("OMS"), customer data (*e.g.*, customer type and location) from SPS's Customer Information System ("CIS"), system data from SPS's Geographic Information System ("GIS"), and asset information from SPS's asset register. Other data sources were used to identify accessibility from public roadways and vegetation density around SPS facilities.

Q. How was the historical NOAA weather data used in the Integrated Resilience & Risk Investment Model?

A. 1898 & Co. used the NOAA weather data for all counties within SPS's service area to create a Major Event Database showing the type, frequency, and intensity of

resiliency events in those counties dating back to 1998. 1898 & Co. used this data to understand the types and frequency of resiliency events that pose a risk to the SPS system. 1898 & Co. then created a county-by-county "heat map" for each major category of resiliency event that impacts SPS's system. County boundaries were also used in the simulation of future resiliency events, as described further below.

Q. What does the historical NOAA weather data show?

A. The NOAA data shows that the SPS service area experienced 21 types of resiliency events spread across seven different categories. This demonstrates the diversity of resiliency risks to which SPS customers are exposed. Excluding drought events, since they are long in duration and challenging to correlate to customer outages, a total of 3,443 weather-based resiliency events have impacted the SPS service territory since 1998, an average of 132.4 events per year. Thunderstorm winds were the most common event type during that period, accounting for 1,226 events. The other most common event types were Hail-Wind (662 events), High Wind (423 events), Flash Flood (314 events), Tornado (268 events), Flood (130 events), and Winter Weather (117) events. This range of event types was a key factor in the design and structure of the SPS SRP.

Figure 2 below shows the distribution of event types for resiliency events in SPS's service area from 1998 to 2023. This information serves as the basis for estimating the future mix and frequency of resiliency events within the Integrated Resilience and Risk Investment Model.

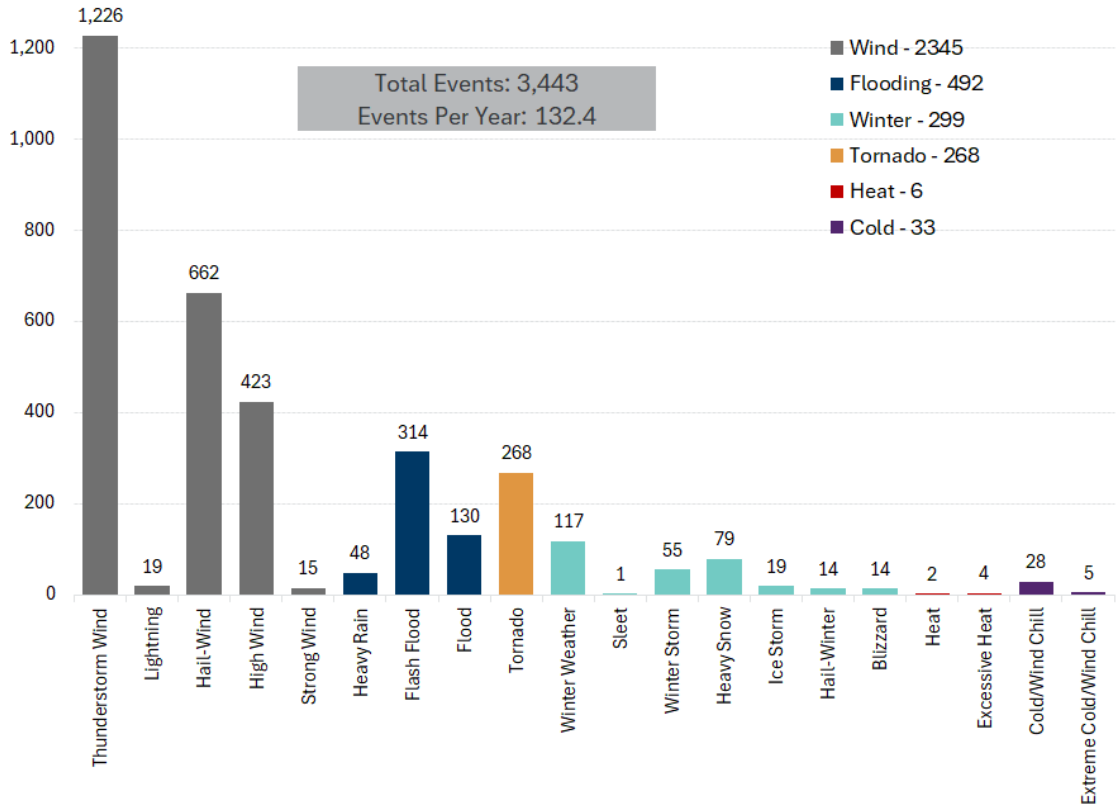


Figure 2: NOAA Events Impacting SPS's Service Area (1998-2023)

Q. How did 1898 & Co. use the data from NOAA and SPS's OMS, CIS, and GIS systems?

A. 1898 & Co. integrated data from the NOAA event database and SPS's OMS, CIS, and GIS to understand the impacts of weather-based resiliency events on the SPS asset base and, by extension, SPS customers.

First, 1898 & Co. used SPS's GIS system and asset register to create a complete list of distribution assets on the SPS system, including data on how they are connected to one another. With this data, 1898 & Co. linked each distribution asset to a "protection zone" based on the nearest upstream protective device (*e.g.*, a fuse, recloser, or breaker). Placing each asset within a protection zone allowed 1898 & Co. to target discrete portions of vulnerable infrastructure on a circuit for

resilience investments. The assets within a protection zone were evaluated as a group to identify a potential resilience investment for evaluation.

Second, 1898 & Co. mapped the NOAA historical event data to historical outage data from the OMS. For each historical resiliency event, the Major Events Database catalogues the SPS system impact and the duration of the impact based on historical outage data. 1898 & Co. used time stamps from both data sets to correlate each event in the NOAA data set to SPS's outage records. The OMS data includes detailed outage information including cause codes for each protective device.

Third, 1898 & Co. linked the GIS and OMS information to understand the relationship between infrastructure vulnerabilities, such as asset age and vegetation density around conductors, and the historical outage records. 1898 & Co. used this information to quantify the link between resiliency events and infrastructure vulnerabilities.

Finally, 1898 & Co. linked the CIS to the GIS and OMS to identify customer counts and customer types associated with each protection zone. The customer types include residential, small commercial and industrial ("C&I"), large C&I, and critical customers. This linkage establishes the relationship between assets and the customers they serve. Customer data was combined with outage data to estimate the CMI for each event by customer type. The CMI was then assigned a dollar value using the DOE ICE Calculator.

Q. What do the correlations between these datasets show?

A. Mapping the datasets shows: (1) the significant impacts resiliency events have on customers, (2) which resiliency events drive outages, and (3) the average impact of different event types.

Over the period of 2010 through 2023, SPS recorded outages of approximately 417.8 million CMI. 1898 & Co. mapped approximately 273.1 million CMI, over 65% of all CMI, to one of the 1,924 NOAA events from Figure 2. Based on this correlation, 1898 & Co. estimated the CMI per event. Utilizing this impact per event from this correlation and the frequency data from the 25-year data set, 1898 & Co. estimated the annual average customer outages per event to understand which event types drive outages for SPS customers.

Table 1 provides a prioritization of the resiliency events evaluated by 1898 & Co. that impacted SPS customers. The table also includes the relative ranking of the event frequency and impact. The information in the table is the core event data utilized within the Integrated Resilience & Risk Investment Model to estimate the quantified benefits of resilience investments across the system. The various categories of winter and wind events account for the top 8 event types impacting SPS customers. These 8 event types account for 97% of the annual average customer outages. The first three events, Winter Storm, Ice Storm, and Thunderstorm Wind, have similar annual average CMI at just over 4 million a year. These three events impact customers approximately the same amount on an annual average basis, however, both of the winter category events are lower-frequency

high-impact events, while Thunderstorm Wind is a high-frequency lower-impact event.

Table 1: Prioritization of Weather-Based Resiliency Events							
No.	Event Category	Event Type	1998 – 2023 Avg Events / Year	CMI Per Event	Annual Average CMI	Event Frequency Rank	Event Impact Rank
1	Winter	Winter Storm	2.12	2,077,142	4,393,954	9	2
2	Winter	Ice Storm	0.73	5,915,109	4,322,580	12	1
3	Wind	Thunderstorm Wind	47.15	86,174	4,063,436	1	7
4	Wind	High Wind	16.27	145,453	2,366,409	3	5
5	Wind	Hail-Wind	25.46	70,445	1,793,630	2	8
6	Winter	Heavy Snow	3.04	270,977	823,354	8	4
7	Winter	Blizzard	0.54	976,731	525,932	15	3
8	Winter	Winter Weather	4.50	105,752	475,882	7	6
9	Flooding	Flash Flood	12.08	35,879	433,306	4	9
10	Flooding	Flood	5.00	7,361	36,805	6	15
11	Flooding	Heavy Rain	1.85	18,915	34,920	10	14
12	Cold	Cold/Wind Chill	1.08	30,234	32,559	11	12
13	Tornado	Tornado	10.31	1,975	20,362	5	18
14	Wind	Strong Wind	0.58	30,814	17,777	14	11
15	Winter	Hail-Winter	0.54	21,814	11,746	15	13
16	Wind	Lightning	0.73	7,112	5,197	12	16
17	Heat	Heat	0.08	32,855	2,527	19	10
18	Heat	Excessive Heat	0.15	2,398	369	18	17
19	Cold	Extreme Cold/Wind Chill	0.19	1,261	243	17	19
20	Winter	Sleet	0.04	0	0	20	20

Table 1: Prioritization of Resiliency Events

Q. Are there any unique characteristics of the SPS service area that 1898 & Co. factored into its event modeling?

A. Yes. SPS's service area covers over 33 million acres in the Panhandle and South Plains of Texas. This area is remote and generally rural in character, with pockets of urban development. The sparse population throughout most of the service area means that many smaller communities are served through radial distribution feeds.

Many SPS feeders serve a relatively small number of customers, and many customers can only receive service from one substation. This limits the opportunities to tie feeders together for backfeed. It also creates access issues that can lengthen restoration times when SPS must deploy personnel to restore service after an outage. These challenges underscore the need to harden SPS's system and modernize its protection schemes to protect vulnerable assets against the risks posed by resiliency events.

Q. What system vulnerability characteristics factored into 1898 & Co.'s modeling?

A. The analysis accounted for several infrastructure vulnerability characteristics that make an asset more likely to fail during a resiliency event or have potential to increase restoration times. 1898 & Co. used SPS's asset register to identify the specifications, age, and condition of existing SPS assets. These characteristics were used to understand each asset's expected useful life and likelihood of failure. While the service territory does not have significant vegetation density, the evaluation estimated the vegetation density for all conductors on the system. 1898 & Co. also used street access and geographical location (urban, suburban, or rural) to quantify the accessibility of individual assets and provide a better understanding of the factors that can impact restoration times.

Q. How did 1898 & Co. use this data for events and system vulnerabilities to model the resiliency benefits for various investments?

A. 1898 & Co. used the weather resiliency event and system vulnerability data in three different analytics models: (1) the Resilience Event Simulation Model, (2) the

Outage Mitigation Resilience and Risk Mitigation Model, and (3) the Equipment Failure Resilience and Risk Mitigation Model. Each of these models estimates the expected avoided costs (including resilience event costs) and avoided customer outages (including resilience event outages), providing consistency in the results between each analytics engine. Each analytics model is designed to estimate the resilience and risk benefits of different resiliency investments based on the nature and structure of the available data, asset types, benefit streams, and failure types. Each analytics model is used to calculate the range of potential restoration costs and CMI under both "Status Quo" and "Investment" scenarios for each investment activity proposed in the SRP.

Q. How did 1898 & Co. model resilience and risk benefits in the Resilience Event Simulation Model?

A. The Resilience Event Simulation model includes three modules: (1) Major Event Database, (2) System Vulnerability & Event Impact Module, and (3) Resilience Benefit Module. This model was used to estimate benefits for the Distribution Overhead Hardening measure.

The Major Event Database uses the historical evolution of major events from NOAA data to establish an expected frequency of future resiliency events for each county and to estimate the CI and CMI per event based on the historical OMS data. The database employs a Monte Carlo simulation to generate a forecast of weather-based resiliency events likely to impact the SPS system over the next 50 years.

The System Vulnerability & Event Impact Module first estimates the vulnerability of each overhead asset and protection zone. The estimated vulnerability is based on the asset type, age, expected life, vegetation density, and accessibility. Vulnerability is established at both the asset and protection zone level. Based on the vulnerability of the system, the model simulates each of the events from the Major Event Database and its impact on the system to estimate the restoration costs and customer outages for each event. The module simulates the probability of protection zone failure based on the vulnerability of the assets in each zone and the strength of the event. After identifying the number of probability-weighted protection zones to experience an outage, the module builds a restoration profile for each protection zone, which allows it to estimate the duration of the outage at the protection zone level. The module also probabilistically estimates the number of asset failures within each protection zone and estimates the restoration costs based on the number and type of failed assets and the expected restoration costs. This evaluation is performed for both a Status Quo and Investment scenario.

The result of this module is the benefit of resilience investment (*i.e.*, the mitigation of resiliency events over the lifecycle of the investment) for each event type. To estimate these benefits, the Resilience Benefit Module combines the results of the Monte Carlo simulation from the Major Event Database with the forecast of events each year and the restoration and CMI benefits from each event to estimate the lifecycle benefits of resilience investment for each protection zone. The module incorporates escalation and discount rates to determine the present value of the lifecycle resilience and risk benefits expected for each protection zone.

Applying the expected investment level for each protection zone, the module then calculates the BCR for each protection zone.

Q. How did 1898 & Co. model resilience and risk benefits in the Outage Mitigation Resilience and Risk Model?

A. The Outage Mitigation Resilience & Risk Model uses the historical OMS data as a starting point and recalculates each outage assuming the proposed resiliency investments had been in place. This approach fundamentally assumes that future outages will be similar to historical outages. On average, this assumption is appropriate for performing the benefits assessment for investments. 1898 & Co. used this modeling approach for the Distribution System Protection Modernization measure.

Using each outage's recalculated CI and CMI, the DOE ICE Calculator monetizes the mitigated outages by considering the number and types of customers impacted and the outage duration. Additionally, the avoided cost of deploying restoration crews is counted as a benefit for outages that are completely mitigated.

The lifecycle present value of avoided customer outages and crew deployments is calculated by adjusting for inflation and discount rate over the lifecycle of the investment. This produces a lifecycle present value of benefits that can be directly compared to the cost of the investment through the BCR.

Q. How did 1898 & Co. model resilience and risk benefits in the Equipment Failure Resilience & Risk Model?

A. The Equipment Failure Risk & Resiliency Model calculates the benefits of replacing existing infrastructure. It forecasts the probability-weighted consequence

of failure for a range of failure types, including NOAA events. The failure types are based on how assets fail over their lifecycle, including inspection-based failures. Consequences are estimated for a range of factors but fall into two main categories. The first category is reactive or restoration costs. The second category is customer-based outages. This category is the monetization of customer outages in the event of an asset failure. This modeling approach was utilized for the Distribution Overhead Hardening and Distribution System Protection Modernization measures.

This approach also calculates each asset's lifecycle reactive costs and customer outage costs for a Status Quo scenario and an Investment scenario. The benefit of replacing infrastructure is the difference between the two scenarios, the avoided resiliency risk and the lifecycle costs. This analysis provides a clear calculation of expected benefits from implementation of particular resiliency measures.

Q. Did 1898 & Co.'s modeling include prioritization of resiliency investments?

A. Yes. The Plan Development Module integrates the quantified benefit-cost results from each of the three analytics models, normalizes to account for and prevent double-counting benefits, and captures efficiencies gained through investment bundling approaches. SPS intends to execute the Distribution Overhead Hardening and Distribution System Protection Modernization measures independently at the circuit level. In alignment with this strategy, 1898 & Co. aggregated the protection zones and organized the applicable measures by circuit. The module estimates the avoided utility restoration costs, avoided customer outages measured in CMI, the

avoided monetized CMI, and investment level for the combined measures for each circuit and then ranks the circuits by their combined resilience and risk BCR.

This resilience and risk-based prioritization facilitates the identification of resiliency investments that will provide the greatest net benefit for SPS customers. Prioritizing and optimizing investments across the SPS system provides confidence that the overall investment level is appropriate, achievable, and will maximize the value of the SRP.

1898 & Co. collaborated with SPS in selecting specific investment activities to include within the SRP. The implementation approach prioritizes investment activities by considering both the BCR of an activity and the wildfire risk present in that geographic area, while also considering SPS's execution constraints. With this data, SPS was able to focus both on system resiliency in high-risk areas and the most effective resiliency investments.

Q. What are the benefits of 1898 & Co.'s approach to evaluating resiliency investments?

A. This approach has several benefits:

1. *It is comprehensive.* 1898 & Co. evaluated nearly all of the assets on the SPS distribution system to identify opportunities for resiliency investments. By considering and evaluating the entire distribution system on a consistent basis, the results of the Integrated Resilience and Risk Investment Model provide confidence that subsets of SPS's distribution assets are not overlooked for potential resilience benefit.

2. *It is customer focused.* 1898 & Co.'s approach involves breaking the SPS system into protection zones with a known number and type of customers. Protection zones are established based on the nearest upstream protective device. The failure of a single asset downstream of a protective device can cause a customer outage in that protection zone. Thus, aggregating assets into protection zones and evaluating investment activities at that level enables the evaluation to provide a direct link between investments in vulnerable infrastructure and benefits to customers.

3. *It is asset-centric.* The granularity of modeling at the asset level and identifying vulnerable equipment for replacement allows SPS to invest in portions of the system that provide the most value to customers, as measured by monetizing the reduction in CMI and avoided restoration costs. With the number of assets in the SPS system and the range of resiliency event types that impact the SPS service area, careful choices must be made to both prioritize the right investments and enhance resilience across the system. Without this granularity, a suboptimal or inefficient level of investment could occur.

4. *It is practical.* This approach balances robust historical data with SPS's operational expertise to identify resiliency investments that will have a practical impact. Data-only approaches may identify resiliency solutions that work in theory but not in practice. In contrast, over-reliance on operational experience can elevate a utility's perception of risk above what is borne out by the data. 1898 & Co.'s approach balances these two

viewpoints to identify resiliency investments that will have a practical impact for customers across the SPS system in Texas.

VII. RESILIENCE INVESTMENT STUDY RESULTS

Q. Please summarize the results of the Benefit-Cost Analysis ("BCA") performed across SPS's distribution system.

A. 1898 & Co. identified nearly $2 billion of potential resiliency investment on the SPS system with quantified benefits in excess of costs for customers. These potential investments have an average BCR of 2.1.

For the Distribution Overhead Hardening measure, 1898 & Co. evaluated 11,793 potential resiliency investments across the system. Approximately $1.76 billion, or 54.3% of the total potential investment level, has quantified benefits in excess of cost. For investments with a BCR greater than or equal to 1.0, the evaluation shows an expected decrease in CMI of approximately 54% with an average BCR of 2.1.

For the Mainline Automated Reclosing Deployment program, the main program in the Distribution System Protection Modernization measure, 1898 & Co. evaluated 459 circuits. Approximately $75 million, or 38% of the total potential investment level has quantified benefits in excess of cost. For investments with a BCR greater than or equal to 1.0, the evaluation shows an expected decrease in CMI of approximately 38% with an average BCR of 3.0.

For the Lateral Reclosing Deployment program, the second program in the Distribution System Protection Modernization measure, 1898 & Co. evaluated 10,800 protection zones. Approximately $1.7 million, or 4% of the total potential

investment level has quantified benefits in excess of cost. For investments with a BCR greater than or equal to 1.0, the evaluation shows an expected decrease in CMI of approximately 21% with an average BCR of 1.9.

The Communication Modernization measure is a necessary investment to fully realize the benefits of the Distribution System Protection Modernization measure. Without the investment in Communication Modernization, SPS cannot remotely monitor, control, and change settings on the protective devices deployed under Distribution System Protection Modernization measure. To evaluate the BCA for this measure, 1898 & Co. estimated the excess quantified benefits from the Mainline Automated Recloser Deployment program. When combining the Mainline Automated Recloser Deployment program and Communication Modernization measure, the BCR of the combined programs is 1.8. This shows that the investments in the Communication Modernization measure are expected to produce benefits in excess of costs for customers.

Q. Please summarize the identified investments from the Resiliency Investment Study that are included in the SPS SRP.

A. Table 2 provides a summary of the investment level for each of the measures evaluated by 1898 & Co. The table also includes wildfire-specific investment activities that were not evaluated by 1898 & Co. Consistent with SPS's project prioritization approach, Table 2 is organized by (1) wildfire risk (Tier 3 being the highest risk), and (2) investment activity type (*i.e.*, BCR-driven or wildfire-specific). For the measures evaluated by 1898 & Co. the SRP's proposed investment level is $425.1 million (in 2024 dollars).

Table 2: SRP Investment Summary (2024 $ in Millions)					
Wildfire Tier / Investment Activity Type	Distribution Overhead Hardening Measure	Distribution System Protection Modernization Measure		Communication Modernization	Total
	Distribution Circuit Hardening Rebuilds Program	Mainline Automated Reclosing Deployment Program	Lateral Reclosing Deployment Program		
Wildfire Tier 3	**$155.8**	**$37.8**	**$0**		**$193.6**
BCR Analysis Activities	$154.1	$35.0	$0		$189.1
Wildfire Specific Activities	$1.7	$2.7	$0		$4.4
Wildfire Tier 2	**$61.2**	**$22.3**	**$0**		**$83.5**
BCR Analysis Activities	$60.6	$21.1	$0		$81.7
Wildfire Specific Activities	$0.6	$1.3	$0		$1.9
Wildfire Tier 1	**$17.8**	**$23.6**	**$2.0**		**$43.4**
BCR Analysis Activities	$17.8	$23.6	$2.0		$43.4
Wildfire Specific Activities	$0	$0	$0		$0
Total	**$234.8**	**$83.7**	**$2.0**	**$104.6**	**$425.1**
BCR Analysis Activities	$232.5	$79.7	$2.0	$104.6	$418.8
Wildfire Specific Activities	$2.4	$4.0	$0		$6.4

Table 2 SRP Investment Summary (2024 $ in Millions)

The Distribution Overhead Hardening measure accounts for most of the investment with 55.2% of the total, followed by Communication Modernization at 24.6%. The Mainline Automated Reclosing Deployment program is approximately 19.7% of the total, with the Lateral Reclosing Deployment program making up the smallest portion at 0.5%. From a wildfire tier perspective, Tier 3 includes approximately 60% of the total for the Distribution Overhead Hardening and Distribution System Protection Modernization measures. Wildfire Tier 2 accounts for approximately 26% of the total, and Tier 1 accounts for 14%.

Q. What are the results of the quantified Benefit Cost Analysis for these SRP investments?

A. Table 3 shows the BCA results for the investments proposed in the SRP. The investment dollars in the table do not include any of the wildfire-specific activities from Table 2. For the investments evaluated by 1898 & Co., the overall BCR is approximately 3.4.

Table 3: Benefit-Cost Evaluation Summary				
Measure / Program	Avg. BCR	SRP Investment (2024$)	Benefits (2024$)	% Improvement in CMI
Distribution Overhead Hardening Measure (Distribution Circuit Hardening Rebuild Program)	4.7	$232.5M	$1,094.5M	58%
Distribution System Protection Modernization: Mainline Automated Reclosing Deployment Program[1]	4.2	$79.7M	$333.0M	37%
Distribution System Protection Modernization: Lateral Reclosing Deployment Program	1.8	$2.0M	$3.5M	21%
Communication Modernization[1]	N/A	$104.6M	$104.6M	N/A
Total	**3.4**	**$418.8M**	**$1,431M**	**N/A**

Table 3 Benefit-Cost Evaluation Summary

These investments also show a significant improvement in customer outages, approximately 58% for those circuits where hardening investment is made and approximately 37% for mainline automation.

Q. Why are the investment values in Tables 2 and 3 less than the cost estimates that SPS presents for the same measures in the SRP?

A. Tables 2 and 3 present the total proposed SRP investment in 2024 dollars. The cost estimates SPS presents in the SRP are nominal values that include annual escalation

[11] The Communication Modernization investment enables the full effectiveness of the mainline automated reclosing deployment program. Section 6.2.4.1 of the Resilience Investment Study showed a BCR of 4.3 for the mainline automation program. The combined program BCR is 1.8.

over the three-year investment period. The Resilience & Risk Investment Model uses present values to make an apples-to-apples comparison of the present costs of investments against the present value of their benefits over a 50-year expected life.

Q. What conclusions can be drawn from the Resilience Investment Study?

A. The Resilience Investment Study provides evidence in support of the following conclusions:

- The resilience and risk BCR value is a robust and reliable measure to help understand the justification for resilience investment activities. This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for customers.
- The benefit cost evaluation shows significant opportunity to improve distribution system resiliency for SPS customers with nearly $2 billion of investment with a BCR greater than or equal to 1.0.
- The investments selected for the SRP that were evaluated by 1898 & Co. are expected to provide benefits in excess of costs for SPS customers with an average BCR of 3.4.
- The investments included in the Distribution Overhead Hardening measure have an average BCR of 4.7 and are expected to decrease customer outages by 58%.
- The investments in the Mainline Automated Reclosing Deployment program have an average BCR of 4.2 and are expected to decrease customer outages by 37%.

- The investments in the Lateral Reclosing Deployment program have an average BCR of 1.8 and are expected to decrease customer outages by 21%.
- Communication Modernization is a key investment to unlock the full potential of other investments in the SRP, particularly investments in the Distribution System Protection Modernization measure. The combined BCR for the Communication Modernization and Distribution System Protection Modernization measures is 1.8.
- The Plan will benefit all SPS customers. Avoided outage restoration costs are shared by all distribution customers. Additionally, distribution customers will experience fewer storm outages from both direct and indirect causes. Direct benefits are realized by those customers whose infrastructure is located directly downstream of the resiliency investment. Indirect benefits are realized by all distribution customers, since storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.
- The expected resilience investment benefits are conservative. First, the benefits outlined above are only direct benefits to specific resiliency measures and do not factor in the indirect benefits from lower overall storm restoration durations. Second, the DOE ICE Calculator is likely conservative for residential customers, as the underlying data pre-dates the significant advancements in societal use of electronic devices and technologies and trends toward work-from-home arrangements, and the DOE ICE Calculator has not been updated to account for this societal shift.

Third, the quantified benefit-cost assessment has carefully included the full cost of implementing resiliency investments; however, the full level of benefits has not been captured. Specifically, the evaluation has not incorporated qualitative benefits associated with enhanced safety or service improvement in areas of lower performance.

- The SRP is an integrated portfolio of measures and investments designed to collectively prevent, withstand, mitigate, and more promptly recover from the risks posed to SPS's system from a wide range of resiliency events. Excluding any programs within the proposed measures may impact the expected benefit of the remaining programs or measures.

Q. Does this conclude your direct testimony?

A. Yes.

AFFIDAVIT

STATE OF MISSOURI)
)
COUNTY OF JACKSON)

JASON D. DE STIGTER, first being sworn on his oath, states:

I am the witness identified in the preceding testimony. I am over 18 years of age, of sound mind, and am capable of making this affidavit. I have read the testimony and the accompanying attachments and am familiar with the contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

JASON D. DE STIGTER

Subscribed and sworn to before me this 18 day of December 2024 by JASON D. DE STIGTER.

GENNIFER LEGATE
Notary Public - Notary Seal
STATE OF MISSOURI
Jackson County
My Commission Expires: Aug. 06, 2028
Commission # 24117927

Notary Public, State of Missouri

My Commission Expires: Aug. 06, 2028

1898 & Co.



Jason De Stigter, PE

Director - Utility Investment Planning

Jason leads the Utility Investment Planning business line at 1898 & Co., part of Burns & McDonnell. In this role, Jason is responsible for business development, marketing, staff training and development, solution and product development, and overall project delivery within the business line. The Utility Investment Planning business line supports electric utilities in developing long-term investment plans and portfolios to meet one or all of the following objectives: 1) aging infrastructure, 2) reliability, 3) resilience or system hardening, and 4) electrification. The business line owns solutions and tools around each of offerings to produce data-driven decisions. Jason is the main architect and solution developer of the data-driven analytic solutions for each of the four offerings.

Jason has 17 years of extensive experience in performing business case evaluation on a variety of project types helping utility clients with difficult investment decisions. Jason also has a deep financial and economic analysis background and specializes in business case evaluation and risk assessment and management for utility client. Jason has extensive experience modeling risk for utility industry clients. His modeling experience includes developing complex and innovative risk analysis models using industry leading risk analysis software tools employing Monte Carlo simulation and Optimization algorithms. His experience includes performing risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems for aging infrastructure, system resilience, reliability and distribution automation, and electrification. Jason also serves as expert witness for many of these engagements supporting the full regulatory process.

Education

B.S. / Engineering
B.A. / Business Administration

Registrations

- Professional Engineer (KS)

8 years with 1898 & Co.
17 years of experience

Visit my LinkedIn profile.

1898 & Co.

TESTIMONY/REGULATORY FILING EXPERIENCE

Utility Company	Regulatory Agency	Docket No. | Year	Subject
AEP Texas	Public Utility Commission of Texas	57057 | 2024 Direct Testimony (pg. 481-499) Filing/Sponsoring Report (pg. 55-175) Case is still pending	System Resiliency Plan (SRP) 2025-2027
Texas-New Mexico Power	Public Utility Commission of Texas	56954 | 2024 Direct Testimony (pg. 746-771) Filing/Sponsoring Report (pg. 435-645) Case has reached an initial settlement agreement	System Resiliency Plan (SRP) 2025-2027
Ohio Power Company (AEP Ohio)	Public Service Commission of Ohio	24-787-EL-RDR | 2024 Direct Testimony (pg. 1-13) Filing/Sponsoring Report (pg. 27-50)	gridSMART® Phase 3 DACR Project
Entergy	Public Utility Commission of Texas	56735 | 2024 Direct Testimony (pg. 52-71) Filing/Sponsoring Report (pg. 84-193)	Texas Future Ready Resiliency Plan (Phase 1)
FirstEnergy Pennsylvania Electric Company	Pennsylvania Public Utility Commission	R-2024-3047068 | 2024 Rebuttal Testimony Not Publicly available	Enhanced Vegetation Management Program Benefit Cost Analysis
Oncor	Public Utility Commission of Texas	56545 | 2024 Direct Testimony (620-649) Filing/Sponsoring Report (pg. 229-460) Rebuttal Testimony Case has an initial settlement agreement	System Resiliency Plan (SRP) 2025-2027
Baltimore Gas & Electric	Maryland Public Service Commission	9692 | 2023 1898 Technical Report (No. 1 Apte Direct Testimony pg. 137-276) Rebuttal Testimony (No. 71) Oral Testimony	2024 – 2026 Mutli-Year Plan (MYP): Resilience Investment Plan
Southern Indiana Gas and Electric Company	Indiana Utility Regulatory Commission	45894 | 2023 Direct Testimony Rebuttal Testimony Waived on providing Oral Testimony	CIE South Transmission Distribution Storage System Improvement Charge (TDSIC) Plan
Entergy New Orleans	New Orleans City Council	UD-21-03 | 2022 *Testimony not provided, case is still pending	2023-2033 Storm Resiliency Plan
Entergy Louisiana	Louisiana Public Service Commission	U-36625 | 2022 Direct Testimony Filing/Sponsoring Report LPSC Approved First 3 Yrs or the plan	2023-2033 Storm Resiliency Plan
Tampa Electric Company (TEC)	Florida Public Service Commission	20220048-EI | 2022 Direct Testimony (412-485) Filing/Sponsoring Report (141-222) Oral Testimony Provided	2022 – 2031 Storm Protection Plan (SPP)
Oklahoma Gas and Electric Company (OG&E)	Oklahoma Corporation Commission	202100164 | 2022 Direct Testimony (1-45) Filing/Sponsoring Report (46-181) Rebuttal Testimony Not in Public Domain	Grid Enhancement Business Case for 2020 & 2021 Investment

Utility Company	Regulatory Agency	Docket No. | Year	Subject
Tampa Electric Company (TEC)	Florida Public Service Commission	20200067-EI | 2020 Direct Testimony (549-623) Filing/Sponsoring Report (100-180) Rebuttal Testimony (72-105)	2020 – 2029 Storm Protection Plan (SPP)
Indianapolis Power & Light Company (now AES Indiana)	Indiana Utility Regulatory Commission	45264 | 2019 Direct Testimony Filing/Sponsoring Report Rebuttal Testimony Oral Testimony Provided	Indianapolis Power & Light Company Transmission Distribution Storage System Improvement Charge (TDSIC) Plan

Additionally, Jason testified in front of the State of Alaska Senate and House Resource committees on project economics and challenges of the AKLNG project.

PROJECT EXPERIENCE

System Resiliency Plan (SRP) Analysis & Investment Study – Benefit Cost Analysis / AEP Texas

Texas / 2024-Current

Project director and Witness for performing a cost benefit evaluation of resiliency investments for AEP Texas' System Resiliency Plan (SRP) for $350 million of distribution investment over the 2025 to 2027 time horizon. The project utilized 1898 & Co.'s Storm Resiliency Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 89,000 potential resilience investments in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model organized the system into 50 mile by 50 mile system sections and models 49 storm events against each section and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening for both an overhead hardening and underground conversion. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects.. 1898 & Co. evaluated distribution overhead hardening investments, underground conversions, crossing upgrades and vegetation management. The results of the project included a protection zone and circuit level benefit cost results for all 89,000 protection zones and 1,470 circuits on AEP Texas' system. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. 1898 & Co. is supporting the regulatory process to include responding to data requests and interrogatories.

System Resiliency Plan (SRP) Analysis & Investment Study – Benefit Cost Analysis / Texas New Mexico Power (TNMP)

Texas / 2024-Current

Project director and Witness for performing a cost benefit evaluation of resiliency investments for TNMP's System Resiliency Plan (SRP) for $750 million of distribution investment over the 2025 to 2027 time horizon. The project utilized 1898 & Co.'s Integrated Resilience & Risk Investment Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 10,500 potential resilience investments in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The modeling included building the relationships between NOAA weather data, historical OMS records, and GIS infrastructure data to understand the relationship between various weather events (thunderstorms, ice storms, blizzards, heat events, etc.) the number of customers impacted and the infrastructure vulnerability. The model then utilized this relationship to forecast future events and estimate the life-cycle impacts of not investing in the distribution system and with investments. 1898 & Co. evaluated distribution overhead hardening investments, protection modernization, vegetation management, and flood mitigation. The results of the project included a protection zone and circuit level benefit cost results for all 10,500 protection zones and 337 circuits on TNMP's system. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. 1898 & Co. is supporting the regulatory process to include responding to data requests and interrogatories.

Distribution Automation Circuit Reconfiguration Phase 3 Benefit Cost Analysis / AEP Ohio

Ohio / 2024-Current

Project director and Witness for performing a cost benefit evaluation for potential distribution automation circuit reconfiguration (DACR) investments across the AEP Ohio system. The project evaluated nearly 1,500 circuits across the system for investments in recloser deployment, new tie lines, and reconductoring. It also considered the effectiveness of each scheme. The evaluation identified over 330 circuits where the customer benefits are in excess of costs. The 1898 & Co. investment benefits cost assessment report and Jason written testimony were included in the initial filing. 1898 & Co. is supporting the regulatory process to include responding to data requests and interrogatories.

Enhanced Vegetation Management Benefit Cost Analysis Evaluation/ FirstEnergy Pennsylvania Electric Company

Pennsylvania / 2024

Project director and Witness for performing a scenario benefit cost evaluation for FirstEnergy Pennsylvania's Enhanced Vegetation Management program that is part of their rate case. The evaluation estimated the monetized customer benefits based on historical outage records for a range of improvement scenarios. The evaluation showed that an improvement of approximately 20-25 percent in vegetation related outages provides benefits in excess of costs for customers. Jason provided rebuttal testimony.

System Resiliency Plan (SRP) Benefit Cost Analysis and Plan Development / Oncor

Texas / 2024-Current

Project director and Witness for performing a cost benefit evaluation of resiliency investments for Oncor's System Resiliency Plan (SRP) for $3.4 billion of distribution investment over the 2025 to 2027 time horizon. The project utilized 1898 & Co.'s Integrated Resilience & Risk Investment Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 175,000 potential resilience investments in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The modeling included building the relationships between NOAA weather data, historical OMS records, and GIS infrastructure data to understand the relationship between various weather events (thunderstorms, ice storms, blizzards, heat events, etc.)

the number of customers impacted and the infrastructure vulnerability. The model then utilized this relationship to forecast future events and estimate the life-cycle impacts of not investing in the distribution system and with investments. 1898 & Co. evaluated hardening investments, modernization, inspections, and vegetation management. The results of the project included a substation level benefit cost results for all 850+ substations on Oncor's system. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the initial filing. Jason supporting the regulatory process to include responding to data requests and interrogatories. Jason also provide rebuttal testimony. The parties have a settlement agreement that is pending commission approval.

10 Year Storm Resiliency Plan / Entergy Louisiana

Louisiana / 2022-Current

Project director for developing and providing justification for Entergy Louisiana's 2024-2033 10-year Storm Resiliency Plan for its transmission and distribution system to mitigate the impact of major events. The project utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 150,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model organized the system into 50 mile by 50 mile system sections and models 49 storm events against each section and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening for both an overhead hardening and underground conversion. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason is supporting the regulatory process to include responding to data requests and interrogatories.

Resiliency Multi-Year Plan / Baltimore Gas & Electric

Maryland/ 2022-2023

Project director for developing distribution resiliency portfolio of overhead hardening and underground conversions for Baltimore Gas & Electric. Jason led the effort to identify and justify investments for the 2024 through 2026 time horizon. The project utilized 1898 & Co.'s Resilience Investment Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit hardening projects and alternatives in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The output of the analysis included three years of specific distribution investments in overhead hardening and underground conversions and the benefits for those projects. 1898 & Co. provided a technical report that was included as an exhibit to BGE's witness. 1898 & Co supported the discovery process, provided rebuttal testimony, and testified on the stand in August 2023. The case was decided in December 2024. The resilience investment will be evaluated separate from the MYP.

Transmission Distribution Storage System Investment Charge Plan Development/ Southern Indiana Gas and Electric

Indiana / 2021-2023

Project director for developing the portfolio of investment projects for a Southern Indiana Gas and Electric, a CenterPoint company. Jason is leading the effort to identify and justify investments in transmission, substation, and distribution systems over the next 5 years. The evaluation leveraged 1898 & Co.'s AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analysis leveraged utility datasets (GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles) inside the engine's aging infrastructure and reliability analytics. The project included data cleansing, organizing, linking, and transformation and configuration of the holistic risk framework across poles, conductor spans, line transformers, breakers, power transformers, relays, and other assets classes. Jason submitted direct and rebuttal testimony, supported the discovery process. He was waived from oral testimony. Southern Indiana Gas & Electric got their full TDSIC plan approved.

Distribution Automation Plan Development / Confidential Client

Midwest / 2022-Current

Project director for developing and providing justification for a distribution automation circuit configuration investment portfolio for a Midwest Investor-Owned Utility. The evaluation utilized 1898 & Co.'s reliability and distribution automation analytics model inside our AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analytics model estimates the expected benefit of deploying distribution automation to every circuits factoring in scheme effectiveness due to tie-line constraints and conductor capacity. The business case monetized the outage improvement and estimated the project cost to include new reclosers, associated communications upgrades, new tie lines, and conductor upgrades. Jason will serve as the expert witness and sponsor the technical report. The case is expected to be filed in May 2023.

Grid Investment Plan Benefits Assessment / Confidential IOU

Midwest / 2022 - 2023

Project director for development of the benefits assessment for a $2.6 billion grid investment plan. The plan includes investments in distribution circuit upgrades, distribution automation, substation rebuilds, capacity rebuilds, and low voltage conversions to improve reliability and resilience, manage long-term costs, modernize for the future, and decrease risk. The engagement include mapping investments to the underlying asset infrastructure, calculating the benefits using the AssetLens Analytics Engine analytics models, and developing the business case for over 6,000 different investment activities across 6 programs. The analysis and results are formalized within a technical report that will be submitted within the public record.

Grid Enhancement Investment Plan Benefits Assessment / Oklahoma Gas & Electric

Oklahoma / 2021-2022

Project director for development of the benefits assessment for OG&E's 2020 and 2021 Grid Enhancement Plan. The plan includes investments in distribution circuit upgrades, distribution automation, and substation rebuilds totaling nearly $250 million. Jason organized the business case framework including the linkage of investments to benefits approaches and calculating the life-cycle benefits in terms of decreased customer outages and avoided restoration costs. Jason also served as the expert witness for the benefits assessment and has provided direct testimony sponsoring the technical report, supported interrogatories and data requests, and provided rebuttal testimony. OG&E settled the case in June 2022.

2022-2031 Storm Protection Plan Resilience Assessment / Tampa Electric Company

Florida / 2021-2022

Project director for supporting the development of TEC's 2022-2031 10-year Storm Protection Plans for its transmission and distribution system in accordance with Florida Statute 366.96. This project is an update to the original 2020-2029 10-Yr Storm Protection Plan. The project utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 20,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model models nearly 100 storm events and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason supported the regulatory process to include responding to data requests and interrogatories. Jason testified in hearings in Tallahassee in early August 2022. The commission approved nearly all of TEC investment plan.

Long-term Portfolio Development / Public Service New Mexico

New Mexico / 2021-Current

Project director for developing the portfolio of investment projects for Public Service New Mexico (PNM). Jason led the effort to identify and justify investments in PNM's transmission, substation, and distribution systems over the next 20 years. The evaluation leveraged 1898 & Co.'s AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analysis leveraged PNM datasets (GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles) inside the engine's aging infrastructure and reliability analytics. The project included data cleansing, organizing, linking, and transformation and configuration of the holistic risk framework across poles, conductor spans, line transformers, breakers, power transformers, relays, and other assets classes. The evaluation organized all PNM's assets into over 20,000 projects. The risk framework allowed for the calculation of benefit in financial terms across each of the 20,000 projects from, specifically the mitigated reactive and restoration costs and the monetization of customer outages. Finally, the project included budget optimization to identify the point of diminishing returns to provide valuable management insights into the level of needed investment in the system over the next 20 years. The overall investment level is confidential. PNM is currently executing the projects that resulted from the evaluation and moving their overall investment levels to manage system risk.

2020-2029 Storm Protection Plan Resilience Assessment / Tampa Electric Company

Florida / 2019-2020

Project director for supporting the development of TEC's 2020-2029 10-year Storm Protection Plans for its transmission and distribution system in accordance with Florida Statute 366.96. The projects utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 20,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model models nearly 100 storm events and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. Tampa Electric Company $1.5 billion 10-year plan was approved in September 2020. The 1898 & Co. resilience benefit

assessment report and Jason written testimony were included in the filing. Jason supported the regulatory process to include responding to data requests and interrogatories. He also provided rebuttal testimony. Tampa Electric settled with the interveners.

Grid Investment Business Case / Confidential IOU

Southeast / 2021

Project director for development of a business case for all grid investment planned projects over the next 10 years. Business case evaluated both mitigated life-cycle reactive and restoration costs and monetization of customer outages. Investments included traditional rebuilds for reliability and resilience purposes, distribution automation, communications, and deployment of new technologies. The business case was used for internal executive management approvals.

Distribution Investment Plan Development with AssetLens / Evergy

Missouri and Kansas / 2019-Current

Project director for configuration and implementation of AssetLens for Evergy's distribution system across multiple states and jurisdictions. AssetLens is an asset investment planning software developed by 1898 & Co. to 1) automate project identification in T&D systems using typical utility data set and 2) provide business justification for all projects in life-cycle NPV benefit terms. The software ingests a range of datasets to include GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles and performs the necessary cleansing, transformation, and linking. Jason led the effort to configure the risk framework analytics that estimate the risk adjusted life-cycle costs and customer impact for all T&D asset classes including poles, pole tops, primary conductor spans, primary underground sections, secondary cable, line transformers, manholes, conduit, splices in manholes, network assets and more. The analytics employ a risk-based methodology across a range of failure types (various probabilities and consequences) to calculate the annual risk costs for a Status Quo and Investment scenario. Life-cycle risk costs include a range of reactive and restoration costs and the monetization of customer outages. The evaluation organized assets into over 100,000 potential projects and scheduled investments to maximize benefit given budget, schedule, and other technical constraints. The overall investment level is confidential. AssetLens visualizes the project plan geospatially providing specific assets for replacement with the business case results for each project. Evergy's distribution engineering teams has been using AssetLens to develop work orders and executive the project plan. It was also used to support their regulatory filing to the Missouri commission.

Distribution Automation Plan Development / Confidential IOU

Central Midwest / 2021-Current

Project director for development of a distribution automation investment plan for the next 5 years. The project involved using GIS and outage records to circuits that would provide the most benefit from the deployment of reclosers. The effort included estimating the number of devices for each circuit and placement of devices for the first few years of the plan. The business case results include the estimated decrease in customer outages and monetization of the outages for an investment business case. The utility is currently developing work orders for 2022 projects.

Overhead and Underground Business Case Development / Confidential IOU

Upper Midwest / 2021-Current

Project director for development of a business case comparing overhead rebuilds to a new modern standards or undergrounding. The business case was performed from a life-cycle cost perspective and impact to customers over a range of events to include extreme weather. The business case evaluated a range of areas of the system to include urban, rural, and suburban. The result of the evaluation may be used for responding to regulators requests.

Long-term Investment Plan Development / Confidential IOU

Midwest / 2021

Project director for identification and justification of distribution circuit and substation investments for a long-term investment plan. The evaluation utilized the AssetLens Analytics Engine to evaluate a range of investment options across the grid, establish 'ideal' investment levels, and provide direction to the 'ideal' split of investment across the system. The utility utilized the study to help develop their long-term investment plan for executive management approval and regulatory strategy.

Distribution Automation Business Case Pilot / Confidential IOU

Midwest / 2021

Project director for a pilot study on distribution automation project identification and justification. The evaluation performed 8760 modeling to understand system overloading constraints to performing automated load transfer schemes. The constraints analysis was utilized in the business case assessment to understand the percentage of time the scheme could operate and provide benefits to customers and if there was a business case to make other grid investments to unlock potential overloading constraints.

Distribution Reliability Investment Plan Development with AssetLens / Confidential IOU

Midwest / 2020-Current

Project director for development of a 10-year distribution investment plan focused on improving overall system reliability and delivery of AssetLens. The data and analytics-based planning approach included the cleansing, organizing, transformation, and linking of GIS, OMS,

distribution circuit models, customer data, and condition information. The planning analytics included evaluation of the benefits and costs of rebuilding each protection zone, over 40,000, across they system. Benefit profiles included the mitigated reactive and restoration costs and decreased customer outages monetized using the DOE ICE Calculator. The project also included budget optimization to identify the long-term need for investment. The overall investment level is confidential. The client's distribution engineering team is currently utilizing the AssetLens solution to build work orders from the projects identified. The client is also moving toward the more 'ideal' long-term investment levels to manage system risk.

Long Term Electric Transmission and Distribution Capital Plan / Indianapolis Power & Light

Indiana / 2017-2019

Project manager for developing IPL's asset risk model. The asset risk model includes transmission circuit, substation, and distribution circuit assets. The asset risk model was used to identify and prioritize asset replacements for nearly $750 million of the $1.2 billion filing. Jason developed an innovative approach for modeling distribution circuit risk down to the span level. For the risk model, Jason developed an integrated and holistic probability and consequence of failure framework to evaluate any asset consistently. The approach has allowed IPL to prioritize investment across transmission and distribution and substations and circuits. The analysis included using Burns & McDonnell's proprietary capital optimization algorithm to group assets into projects and prioritize projects to maximize risk reduction benefit. Burns & McDonnell prepared two reports that are part of IPL's public record filing. Jason also provided written (direct and rebuttal) and oral testimony. The entire plan (100%) was approved in February of 2020.

Grid Modernization Engineering Study / Entergy

Louisiana/Mississippi/Arkansas/Texas / 2016–2019

Entergy is embarking on a new approach to electric distribution planning, design and engineering to meet the future needs of its customers. The new approach includes developing modernize electric distribution equipment, engineering and design, and construction standards to drive value throughout the supply chain from material purchasing, inventory, system design, and construction. Additionally, the grid modernization approach leverages a modern holistic distribution asset and capital planning process with associated tools (DNV GL's Synergy) to facilitate efficient and robust performance and risk assessment of Entergy's electric distribution system. The approach identifies the portfolio of issues facing a family or cluster of distribution feeders and then develops the ideal portfolio of projects to address to improve feeder performance, cost, and risk.

Project manager for the business case evaluation and capital project prioritization aspects of Grid Modernization Engineering Study for Entergy. For the portfolio of projects, Jason developed a robust business case methodology that calculates risk reduction benefits, reliability improvement, and operational efficiency (i.e. fewer truck rolls) to justify each capital investment.

Entergy intends to use the results of the engineering study to propose a list of grid modernization project to consider for regulatory approval and funding. Additionally, these projects and the holistic planning approach will be the first step in an evolutionary change to build Entergy's grid of the future, ready for the next generation of consumers and system performance.

69 kV Wood Pole Replacement Program Evaluation / Salt River Project (SRP)

Phoenix, Arizona / 2017–2018

Project manager for evaluation of the 'ideal' level of 69 kV wood pole replacement SRP should execute each year. The effort includes development of an asset risk model, including risk framework, and various replacement strategies that maximize risk reduction while also maintaining overall budget levels. The final outcome will include the risk mitigated for the whole portfolio over 30 years for a range of budget levels to identify an 'ideal' overall investment rate.

PRIOR EXPERIENCE

Capital and Operations & Maintenance (O&M) Budget Prioritization / Tulsa Metropolitan Utility Authority (TMUA) Utility Enterprise Initiative

Tulsa, Oklahoma / 2013-2016

Project manager for the Capital Prioritization and Optimization task of TMUA's Asset Management implementation initiative, Utility Enterprise Initiative. He used a 'Project Prioritization and Optimization' solution for several water and wastewater projects as part annual cycle phased approach (executed three of four phases). Jason was responsible for leading workshops with engineering and maintenance staff, developing business case approaches for each water/wastewater project, performing Monte Carlo and optimization simulations, and developing strategies for the Utility's capital improvement plan (CIP) during a period of tight budget constraints to minimize rate increases. TMUA was working toward codifying the process and tool into their own annual budget and rates process. As such, Jason was responsible for developing users guide documentation and holding training on the process and tool for TMUA.

2017 Executive Asset Management Plan Alternatives Evaluation / Washington Suburban Sanitation Commission (WSSC)

Laurel, Maryland / 2015

Project manager for alternatives evaluation to support WSSC in the development of their 2017 Enterprise Asset Management Plan Business Case. Effort included developing forecasted 30-year capital plans

optimizing on level of service, risk and cost. WSSC utilized the results of the evaluation to develop long term forecasts of capital improvements for communication to decision make Capital Prioritization Pilot Project / Salt River Project (SRP)

Project Prioritization / Salt River Project

Arizona / 2013-2014

Subject matter expert for this pilot study for SRP to prioritize and optimize several electrical generation, transmission and distribution planned investments. Allowed SRP management the opportunity to further develop and improve upon their current budget processes and to consider adopting the solution enterprise-wide. Jason's responsibilities included developing business case approaches for several of the pilot study projects and supporting workshops.

Long Term Electric Transmission and Distribution Capital Plan / Duke Energy

Indiana / 2014-2015

Subject matter expert and manager for development of a risk-based electric T&D capital plan that included Duke's long-term electric transmission and distribution (T&D) investments. This work provided evidence of how Duke's investments in its system provided risk reduction benefits and focused spending on high risk assets. As a capital prioritization and risk subject matter expert, he also developed capital plan profiles and resulting risk reduction solutions which were key to showing the value of the 7-year capital plan.

Long Term Electric Transmission and Distribution Capital Plan / Northern Indiana Public Service Company (NIPSCO)

Indiana / 2013-2014

Subject matter expert for development of a long-term $1 billion plus capital plan for NIPSCO's electric T&D infrastructure. A system risk model was developed to analyze and score asset risk across the T&D system for NIPSCO. The model highlighted the risk reduction benefits achieved through NIPSCO's long-term asset replacement program, which is focused on addressing high-risk assets that are nearing the end of their useful life.

Capital Prioritization System Master Plan / Hetch Hetchy Water and Power

California / 2009, 2011, 2012

Primary consultant for this system master plan, developing the analysis and prioritization of recommended capital and O&M projects for the Hetch Hetchy power, transmission and civil asset system. The process utilized a risk-based approach to economically schedule investments to maximize risk reduction given a certain budget constraint. The Hetch Hetchy Reservoir system lies within the scenic Yosemite National Park and provides electricity and water storage for the San Francisco Public Utility Commission.

Capital Project Prioritization with Risk Assessment / Colorado Springs Utilities

Colorado Springs, Colorado / 2008

Primary analyst on an innovative capital project prioritization process for Colorado Springs Utilities' Raw Water System. The engagement applied the Strategic Value Creation process to quantify the physical and financial parameters of capital and O&M projects identified for the utility's raw water system. A wide variety of projects and risk were then prioritized to develop the system capital improvement plan while considering utility risk tolerance, budget constraints and other planning criteria. Monte Carlo simulations were used to quantify the physical and financial parameters of each individual project, and the projects are evaluated and ranked using a consistent and transparent approach.

Jason was responsible for performing the Monte Carlo analysis, understanding the risks of each CAPITAL and O&M project, and prioritizing the projects to reduce the overall risk to the client.

Alaska Liquefied Natural Gas (AKLNG) Economic and Risk Analysis / State of Alaska Departments of Natural Resources and Revenue

Alaska / 2013-2016

Project manager responsible for economic and risk analysis for the AKLNG project on behalf of the State. In this role, Jason developed analysis to explore various project questions and negotiating position to better understand the perspective of each project sponsor and the best position for the State. He routinely developed materials to present to the commissioners of the departments or Natural Resources and Revenue, the State of Alaska legislature, negotiating teams, and the governor's office. On a few occasions, Jason has testified to the state of Alaska legislature of the economics and risks associated with the AKLNG project.

Deep Tunnel Sewerage System (DTSS) Phase 2 Resiliency Assessment / Singapore Public Utilities Board (PUB)

Singapore / 2014-2015

Subject matter expert for an alternative's resiliency assessment of several deep tunnel sewerage systems alternatives for Singapore PUB. In his role for this engagement, Jason created an innovated approach to evaluating the resiliency of several tunneling alternatives including total risk weighted level of service and cost over the asset's life cycle. The assessment identified several key risks impacting each alternative then quantifying the likelihood and the level of service and cost impacts of each risk. Employing Monte Carlo simulation, the risk cost and discount to level of service scores were calculated to develop a range of potential benefit cost ratios for each alternative. Singapore PUB utilized the

process and results to identify a preferred alternative and move forward with key design decisions.

Kirkwood Penstock Risk Evaluation / Hetch Hetchy Water and Power

California / 2014

Project manager for a risk assessment of HHWP's critical Kirkwood Penstock which over 80% of San Francisco Bay's water supply moves through. The risk assessment following guidelines set out by the United States Bureau of Reclamation including a failure modes and effects analysis applying a qualitative scoring-based approach to evaluate the likelihood and consequence of failure for each failure mode. HHWP utilized the results of the evaluation to prioritize investment needs to ensure reliability of this critical asset.

Business Case Evaluation and Risk Analysis / Hampton Roads Sanitation District (HRSD, Wastewater Utility)

Virginia / 2011-2012

Business case evaluation and lead risk consultant for this long-term evaluation of the business case and associated risk of alternative wastewater system master plans. Working with Hampton Roads' senior management team, Jason evaluated the economics and risk of alternative strategic long-term wastewater system expansion plans related to biosolids management, which involved hundreds of millions of dollars in capital and O&M expenditures. This developed a long-term strategy that is now being used to optimize short- and long-term implementation plans for HRSD's wastewater system.

Conveyance Alternative Risk Assessment / Metropolitan Water District

California / 2010

Primary consultant for this engagement which analyzed several water conveyance options for the California State Department of Water Resources. This analysis was focused on capital cost and schedule risk of different multi-billion-dollar canal and tunnel conveyance alternatives. Jason was the risk specialist for the Environmental team for the risk assessment workshop. Utility decision-makers utilized the results to more fully understand the risk inherent in each alternative to decide on a preferred alternative.

Integrated Water Power Plant Economic and Regulatory Assessment / Public Authority for Electricity and Water of Oman

Oman, Middle East / 2009-2010

Primary analyst for the economic and regulatory (tariff) modeling of a new, highly efficient integrated water & power plant. Jason's responsibilities included performing economic and tariff modeling of several different desalination and power plant alternatives and presenting final results to the Chairman of the Public Authority for Electricity and Water of Oman.

AGIA Economic and Risk Modeling / State of Alaska Department of Natural Resources (DNR)

Alaska / 2009-2010

Primary analyst for this economic and risk modeling assignment for the State of Alaska DNR. Analysis included modeling and evaluation of different natural gas pipeline project risk factors, as well as risk mitigation measures the state has within its control. The results of the analysis assisted the State of Alaska in negotiations with other pipeline stakeholders.

Black & Veatch's Energy Market Perspective Emissions Modeling

Overland Park, Kansas / 2012-2013

As part of Black & Veatch's annual release of its Energy Market Perspective, Jason developed a fundamental economic model to calculate emissions prices based on the EPA's Cross State Air Pollution Rule.

Commercial Modeling and Analysis / Alaska Gasline Development Corporation (AGDC)

Anchorage, Alaska / 2010-2011

Lead consultant for ongoing commercial and tariff modeling for AGDC's analysis of in-state pipeline alternatives. This modeling included sensitivity and scenario analysis, midstream tariff modeling, and stakeholder cash flow analysis.

Black & Veatch's Energy Market Perspective

Overland Park, Kansas / 2009-2011

The Energy Market Perspective developed by Black & Veatch uses an integrated market modeling approach to develop price forecasts for energy and natural gas prices. The modeling team, which included Jason, developed forecasts for CO2 taxes, energy demand and peak demand, generation retirements, generation expansion, renewables buildout and transmission expansion. Using these forecasts, the integrated market model used an interactive process of a production cost model for electric prices and a fundamental market model for natural gas prices.

Jason's principal responsibilities included developing forecasts, running and understanding the production cost model for a large region in the United States, and drawing conclusions for the region. The main forecasts Jason developed included energy and peak demand, generation retirements, generation expansion, and transmission expansion. Furthermore, Jason was responsible for developing the final report for the regional perspective.

Alaska Gasline Inducement Act (AGIA) Net Present Value (NPV) and Risk Analysis / State of Alaska Departments of Natural Resources and Revenue

Alaska / 2007-2008

In 2007, the state of Alaska passed the Alaska Gasline Inducement Act (AGIA). This act created a framework for the State to issue a license to build a 1,400 mile pipeline to transport natural gas from the North Slope of Alaska to either the North American market or elsewhere.

Uncertainty for a project of this size (over $30 billion) is understandably significant. In order to quantify this significant uncertainty, risk analysis was performed explicitly with the NPV model to evaluate the level of project risk to the various stakeholders due to various assumptions such as commodity prices, capital cost escalation, project schedule uncertainty, and reserve risk.

Jason performed economic, risk and financial analysis for several different stakeholders for the proposed projects and several sensitivities and alternative scenarios. Jason's main responsibilities included model development/creation, Monte Carlo risk modeling, and understanding risk for each stakeholder. He also performed financial analysis, data validation, and report and presentation support.

Socioeconomic Analysis, Riverbend Unit 3 and Fermi Unit 3 Nuclear Licensing Project / Entergy and Detroit Edison

Louisiana and Michigan / 2007-2008

Senior analyst served as an economist for a detailed socioeconomic analysis associated with the construction and operating license application (COLA) process for Entergy and Detroit Edison. He was responsible for developing population distributions; population projections; demographic characteristics to include age, sex, race and income; transient population distributions; and community characteristics for the surrounding area. Jason was also responsible for writing and reviewing significant portions of the COLA

Market and Economic Analysis / Termobarranquilla

Colombia, South America / 2007-2008

As a senior analyst, Jason provided market analysis, economic analysis and a discounted cash flow model to evaluate the worth of the Termobarranquilla power plant after an energy market restructuring in Colombia. He was responsible for developing an energy market model, economic dispatch model, discounted cash flow model and writing the report.

Taylor Energy Center Need for Power Application / Various Clients

Florida / 2006

Jason performed production costing, economic analysis and other support to facilitate the completion and filing of the Taylor Energy Center (TEC) Need for Power Application (NFP). The NFP provided a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the four separate utilities participating in the project while maintaining consistency with the Florida Public Service Commission statutory requirements. The analysis considered self-build and purchase-power alternatives.

Portfolio of Wind Farms and Coal Fired Plants / Sembcorp Industries Pte Ltd.

China / 2011

Lead consultant to Sembcorp Industries Pte (buy-side), in support of their potential acquisition of an equity position in a Chinese investment company (confidential). This engagement required due diligence site visits and technical and commercial review of a wind portfolio and coal fired generation plant in Shanxi Province, Hebei Province, and Inner Mongolia Autonomous.

Water and Wastewater Utility Independent Engineer's Report / Confidential Client

2011

Primary consultant assisted and prepared an independent engineer's report for a confidential client seeking to divest its portfolio of water and wastewater utilities. The report provided an overview of the systems, the major sources of supplies, rates, and environmental and regulatory issues. Major facilities were evaluated to document the condition of specific utilities. A final report was prepared and delivered to the client for use in its divestment proceedings.

Combined Cycle Due Diligence / Confidential Client

California / 2011

Jason was involved with the technical due diligence of 1,000 megawatt (MW) combined-cycle power plant in the state of California. Jason was responsible for reviewing maintenance and performance reports on plant equipment and safety along with O&M and energy management agreements. Jason also developed the corresponding report sections that summarized the results of the analysis.

Engineer's Report / Philadelphia Gas Works (PGW)

Philadelphia, Pennsylvania / 2010-2011

Lead consultant on the engineer's reports developed for PGW's last two revenue bond issues for $165 million and $150 million, respectively. Proceeds from the bond issues funded needed capital improvements to PGW's distribution system and LNG facilities. The engineer's report summarized the findings of a study of PGW's facilities, management, operations, gas supply, rates and marketing, and customer service, and assessed the financial feasibility of the bond issue.

E.ON US Portfolio Due Diligence, Various Coal, Gas and Hydroelectric Power Plants / E.ON

Kentucky, United States / 2010

Jason performed technical due diligence for the potential sales of approximately 9,500 MW coal, gas and hydroelectric generating assets in the state of Kentucky. Jason was responsible for reviewing maintenance and performance reports on plant equipment and safety along with O&M and energy management agreements. Jason also developed the corresponding report sections that summarized the results of the analysis.

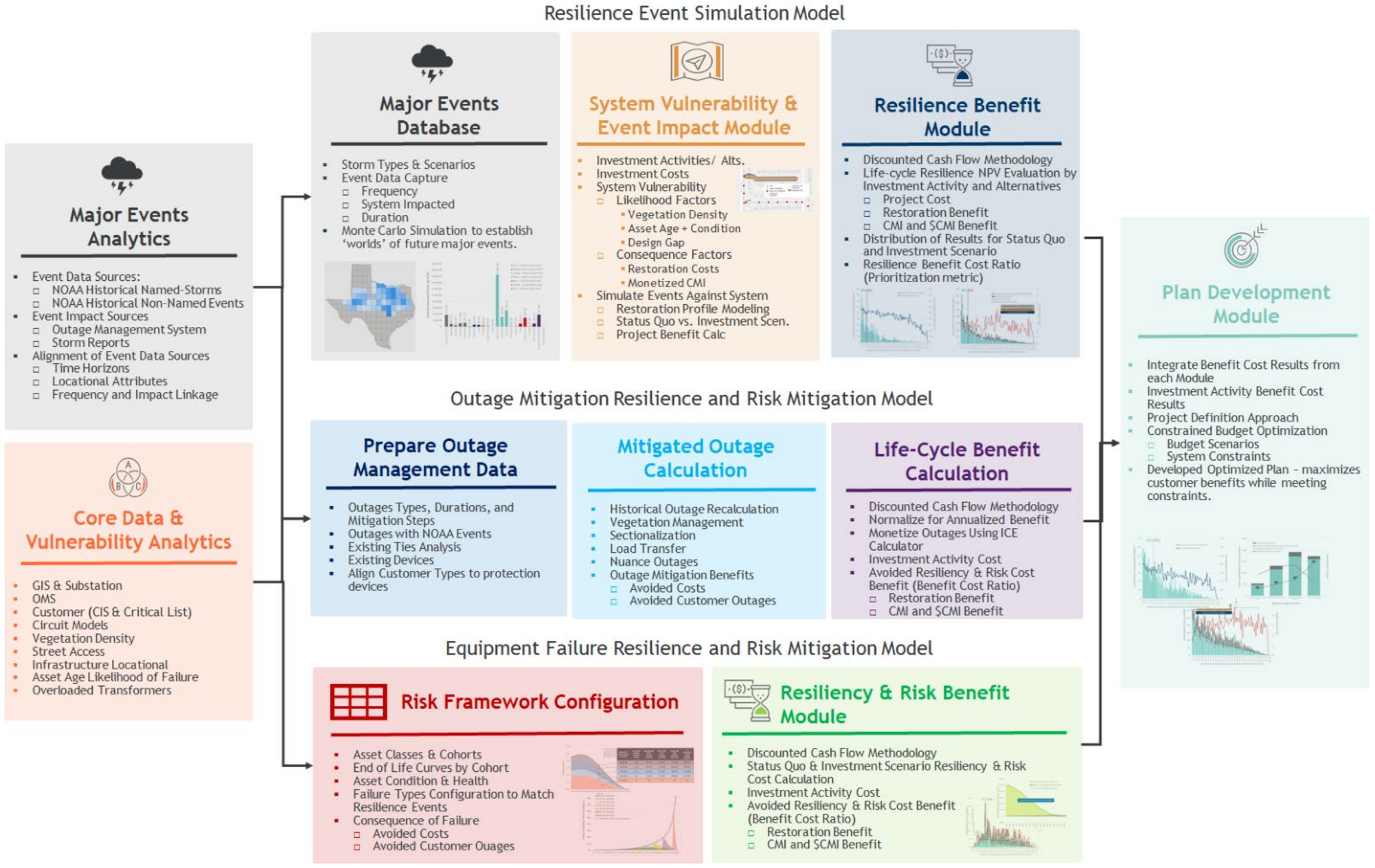
Technical Due Diligence / Con Edison Development, Inc.

2007

Jason performed a technical due diligence assessment of certain power generation facilities in the northeast United States. He was responsible for developing power plant performance sections of the assessment and reviewing O&M, power purchase, maintenance, gas supply, oil supply, electrical interconnection and water supply agreements.

PUBLICATIONS AND PRESENTATIONS

- *Asset Management: A Framework for Maximized Value*, published and featured in Burns & McDonnel's quarterly BenchMark article in 2020. (Video and quoted)
- How IPL Created an Optimized Capital Plan to manage risk across the entire T&D system, published and presented at the 2020 DistribuTECH conference. (Co-Author)
- How IPL solved the challenges of modeling linear assets in their asset risk model by leveraging GIS, published and presented at the 2020 DistribuTECH conference. (Co-Author)
- Capital Planning for Grid Modernization, Building the Grid of Tomorrow, 2018 EUCI course presenter. (Co-presenter)
- *Changing the Way the Grid's Future is Planned*, published Burns & McDonnell white paper in 2017. (Co-Author)
- Monetizing Risk Helps Tulsa Optimize Capital Investments, published in the July 2016 Journal American Water Works Associate (JAWWA). (Co-Author)
- Monte Carlo Simulations Take The Chance Out Of Investment Decisions, published in the April 2016 Breaking Energy. (Co-Author)
- Monetizing Risk – Capital Investment Prioritization and Optimization for Tulsa Metropolitan Utility Authority, published at the 2016 Utility Management Conference. (Co-Author)
- Priorities: Getting the Most From Your Capital Improvement Plan, published in the May 2015 Florida Water Resources Journal. (Author)
- Monetizing Risk – A Capital Investment Prioritization and Optimization Model, presented and published at the 2015 Texas Water Conference. (Co-Author/Presenter)
- How to Get More Reliability Bang from Your Capital Spending Buck, presented and published at the 2014 Florida Water Resources Conference. (Co-Author/Presenter)
- Triple Bottom Line and Monte Carlo Simulation: Business Case Evaluation Methodologies and Testing Sensitivities: Understanding Economic Models and Uncertainty in Results, presented at the 2013 WEFTEC conference workshop titled "WERF Barriers to Biogas Workshop: Learn to Use the Right Economic Methodologies to Evaluate Cost-Saving Projects". (Presenter)
- The Challenge of Regulatory Compliance and Multiple Facility Upgrades – A Progressive System Approach, presented and published at the 2012 WEFTEC conference proceedings. (Co-Author)
- Asset Management and Maintenance Strategies – Balancing Costs and Risk, poster presentation and published at Hydrovision 2011 conference. (Co-Author)


Resilience Event Simulation Model
Major Events Analytics
Event Data Sources:
NOAA Historical Named-Storms
NOAA Historical Non-Named Events
Event Impact Sources
Outage Management System
Storm Reports
Alignment of Event Data Sources
Time Horizons
Locational Attributes
Frequency and Impact Linkage
Major Events Database
Storm Types & Scenarios
Event Data Capture
Frequency
System Impacted
Duration
Monte Carlo Simulation to establish 'worlds' of future major events.
System Vulnerability & Event Impact Module
Investment Activities/ Alts.
Investment Costs
System Vulnerability
Likelihood Factors
Vegetation Density
Asset Age + Condition
Design Gap
Consequence Factors
Restoration Costs
Monetized CMI
Simulate Events Against System
Restoration Profile Modeling
Status Quo vs. Investment Scen.
Project Benefit Calc
Resilience Benefit Module
Discounted Cash Flow Methodology
Life-cycle Resilience NPV Evaluation by Investment Activity and Alternatives
Project Cost
Restoration Benefit
CMI and $CMI Benefit
Distribution of Results for Status Quo and Investment Scenario
Resilience Benefit Cost Ratio (Prioritization metric)
Plan Development Module
Integrate Benefit Cost Results from each Module
Investment Activity Benefit Cost Results
Project Definition Approach
Constrained Budget Optimization
Budget Scenarios
System Constraints
Developed Optimized Plan - maximizes customer benefits while meeting constraints.
Outage Mitigation Resilience and Risk Mitigation Model
Core Data & Vulnerability Analytics
GIS & Substation
OMS
Customer (CIS & Critical List)
Circuit Models
Vegetation Density
Street Access
Infrastructure Locational
Asset Age Likelihood of Failure
Overloaded Transformers
Prepare Outage Management Data
Outages Types, Durations, and Mitigation Steps
Outages with NOAA Events
Existing Ties Analysis
Existing Devices
Align Customer Types to protection devices
Mitigated Outage Calculation
Historical Outage Recalculation
Vegetation Management
Sectionalization
Load Transfer
Nuance Outages
Outage Mitigation Benefits
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Monetize Outages Using ICE Calculator
Investment Activity Cost
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CMI and $CMI Benefit
Equipment Failure Resilience and Risk Mitigation Model
Risk Framework Configuration
Asset Classes & Cohorts
End of Life Curves by Cohort
Asset Condition & Health
Failure Types Configuration to Match Resilience Events
Consequence of Failure
Avoided Costs
Avoided Customer Ouages
Resiliency & Risk Benefit Module
Discounted Cash Flow Methodology
Status Quo & Investment Scenario Resiliency & Risk Cost Calculation
Investment Activity Cost
Avoided Resiliency & Risk Cost Benefit (Benefit Cost Ratio)
Restoration Benefit
CMI and $CMI Benefit

DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§**	**PUBLIC UTILITY COMMISSION**
	§	**OF TEXAS**

DIRECT TESTIMONY
of
ANNE Z. SHERWOOD

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

*(Filename: SherwoodAZSD*irect.docx; *Total Pages:* 25)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
AI	Artificial Intelligence
DSAP	Defensible Space Around Poles
EDM	EDM International
EPC	Engineering Procurement and Construction
EPSS	Enhanced Powerline Safety Settings
GRIP	Grid Resilience and Innovation Partnerships
MOS	Metal Oxide Semiconductor
PUCT	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act
Rule 25.62	16 TAC § 25.62
SRP or Plan	System Resiliency Plan
SPS	Southwestern Public Service Company, a New Mexico corporation
SPWO	Southern Plains Wildfire Outbreak
TAC	Texas Administrative Code
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

DIRECT TESTIMONY
OF
ANNE Z. SHERWOOD

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Anne Z. Sherwood. My business address is 1800 Larimer Street, Denver, Colorado 80202.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") and wholly owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by Xcel Energy Services Inc. ("XES") as Area Vice President of Wildfire Mitigation: Regulatory and Policy. XES is a wholly-owned subsidiary of Xcel Energy and provides an array of support services to SPS and the other utility operating company subsidiaries of Xcel Energy.

Q. Please briefly outline your responsibilities as Area Vice President of Wildfire Mitigation.

A. As Area Vice President of Wildfire Mitigation: Regulatory and Policy, I am responsible for overseeing Xcel Energy's wildfire policy initiatives, conducting wildfire mitigation program planning, and promoting stakeholder and engagement activities with regulatory stakeholders, impacted communities, and other utilities.

Q. Please describe your educational background.

A. I graduated from Wheaton College with a Bachelor of Arts in Political Science in 2002 and earned my Juris Doctor from Northwestern University's Pritzker School of Law in 2006.

Q. Please describe your professional experience.

A. Before transitioning to my current role of Area Vice President – Wildfire Mitigation: Regulatory and Policy in May 2023, I was the Lead Assistant General Counsel of Xcel Energy's Colorado operating utility, Public Service Company of Colorado ("PSCo"). Regulatory and policy matters associated with wildfire issues were within the scope of my responsibilities in that role. Prior to joining Xcel Energy in that role in 2020, I practiced complex commercial litigation for approximately eight years. Before that, I began my legal career practicing high-profile, complex civil rights and criminal litigation for a Chicago-based law firm for five years.

Q. Have you testified before any regulatory authorities?

A. Yes, I submitted testimony on behalf of PSCo in Colorado Public Utilities Commission Docket No. 24A-0296E. I also submitted testimony on behalf of Northern States Power – Minnesota in Minnesota Utilities Commission Public Docket No. E002/GR-24-320.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports the Wildfire Mitigation measure proposed in the SPS System Resiliency Plan ("SRP" or "Plan"), which is comprised of two programs: (1) Wildfire Situational Awareness and (2) Wildfire Physical Mitigation.

Q. Why is wildfire mitigation an integral part of system resiliency for SPS?

A. Wildfire mitigation is especially important for SPS and its service area because of the heightened wildfire risk resulting from the service area's geographic and climate attributes. SPS's service area and the surrounding region are particularly susceptible to wildfires because of the amount of flammable vegetation (known as fuels) in the area, the topography (which can contribute to fire intensity and fire spread), and weather patterns such as wind and drought conditions.

A named category of wildfire event – Southern Plains Wildfire Outbreak ("SPWO") – affects SPS's service area. As described by the Texas A&M Forest Service, "the environment conducive to an SPWO is characterized by dry vegetation, dry west-southwest winds across an area with low relative humidity, above average surface temperatures, an unstable atmosphere, and clear, sunny skies."[1] Texas, and SPS, must monitor for SPWO conditions yearly.

In SPS's largely rural service area, when the growing seasons end, vegetation cures, turns brown, and becomes dormant. Dormant grasses, which cover large portions of the SPS service area, are susceptible to burning from any

[1] Preparing for Wildfires, Southern Plains Wildfire Outbreak, Texas A&M Forest Service, *available at* https://tfsweb.tamu.edu/spwo/. The Texas A&M Forest Service further describes an SPWO event as "a force of nature," which, "much like a hurricane or tornado," "cannot be stopped." *Id.*

source of ignition and can lead to wildfires that can spread significant danger to residents and communities. Additionally, changing weather conditions and extreme weather events contribute to the frequency and severity of drought, while also increasing vegetation (or fuels) growth. In combination, this can lead to the increased frequency and severity of wildfires.

The extent and nature of the wildfire risk in SPS's service area are described in further detail in Section III.B of SPS's SRP and in the Direct Testimony of Ryan Brockbank of EDM International ("EDM"), a consulting firm specializing in wildfire mitigation that SPS engaged to aid in developing its SRP.

As I understand, the Texas Legislature and Public Utility Commission of Texas ("PUCT") have identified "wildfire mitigation and response" as one of the measures available to be used to "enhance the resiliency of the utility's transmission and distribution system."[2] SPS's inclusion of a Wildfire measure is consistent with that and is tailored to SPS's system and service area.

Q. Please summarize your testimony.

A. My testimony supports the Wildfire Mitigation measure of SPS's SRP by addressing the requirements of 16 TAC § 25.62 ("Rule 25.62"). Specifically, I explain the risk the measure addresses, describe the programs within the measure, provide evidence of effectiveness of the measure, identify the expected benefits of the proposed measure, distinguish the programs within the measure from existing SPS programs, explain the alternatives SPS considered to the Wildfire Mitigation

[2] Public Utilities Regulatory Authority ("PURA") § 38.078(b)(10); 16 Texas Administrative Code ("TAC") § 25.62(c)(1)(J).

measure it is proposing, address implementation of the Wildfire Mitigation measure, and identify the metrics SPS proposes to use to evaluate the measure.

III. WILDFIRE MITIGATION MEASURE

A. Resiliency Events and Risks

Q. What resiliency event does SPS prioritize through the Wildfire Mitigation measure?

A. The Wildfire Mitigation measure uses the wildfire mitigation and response method identified in Rule 25.62(c)(1)(J) and is designed to help SPS prevent, withstand, mitigate, and more promptly recover from wildfire risks to its system, which risks I described earlier in my testimony.

Q. How did SPS identify the activities proposed as a part of the Wildfire Mitigation measure?

A. SPS engaged EDM to help assess wildfire risk to the SPS system and to develop a three-tiered Wildfire Risk Map[3] that SPS will use to identify locations and prioritize mitigation programs that would maximize wildfire risk reduction. SPS collaborated with EDM to assess where and how wildfire risks presented by the service area's fuels and topography might affect fire propagation into populated areas, buildings and other structures, and SPS facilities. The Wildfire Risk Map also allows SPS to visualize and understand the wildfire risk level across the different regions of its service area. The Wildfire Risk Map shows the likelihood and potential consequences of a wildfire event within the various regions of the service area. Mr. Brockbank describes how the Wildfire Risk Map was developed

[3] In general, the terms Wildfire Risk Map and Wildfire Operations Map are used interchangeably in direct testimony and in the SRP.

and provides further detail regarding EDM's role in helping SPS operationalize the Wildfire Risk Map for wildfire mitigation efforts.

SPS also relied on weather data presented by 1898 & Co. to help better understand the weather-related resiliency events that could impact the likelihood and severity of wildfire in the SPS service area. As 1898 & Co.'s report discusses, SPS's service area experiences extreme wind, cold, and heat events, all of which can make wildfires more likely and more damaging.

Q. How did SPS use the Wildfire Risk Map to aid its analysis of its system in support of developing its resiliency approach?

A. Using the Wildfire Risk Map and in collaboration with EDM, SPS has assessed its fire risk on the landscape relative to populated areas and its facilities and prioritized its wildfire mitigation efforts. The wildfire risk zones are designated Tier 1 for lower risk, Tier 2 for moderate risk, and Tier 3 for higher risk. Using these risk tier designations, SPS prioritized investments to improve the resiliency of its system and to establish maintenance standards as well as standards for new construction. In areas of elevated wildfire risk, SPS has identified wildfire-focused system improvements that will accompany the overhead hardening and system protection modernization work proposed as a part of the SRP, consistent with standard practice in the industry. For purposes of this SRP, SPS used the Wildfire Risk Map and the risk tiers it identifies to prioritize projects within the Overhead Hardening and Distribution System Protection Modernization measures that correlate with wildfire ignition risk reduction, as described in greater detail by SPS witness Brianne Jole.

SPS also used the Wildfire Risk Map to locate areas of the system that could benefit from the activities proposed as a part of the Wildfire Mitigation measure.[4]

B. Wildfire Mitigation Programs

Q. What programs does SPS propose within the Wildfire Mitigation measure?

A. The measure is composed of two programs: Wildfire Situational Awareness and Wildfire Physical Mitigation. SPS proposes these programs because they are expected to improve SPS's capabilities in preventing wildfire ignition and/or rapidly responding to the same, which in turn will help SPS limit customer outages and restore customer service more promptly in the event of a wildfire-caused outage.

1. Wildfire Situational Awareness Program

Q. Please describe the Wildfire Situational Awareness Program.

A. The Wildfire Situational Awareness Program includes a suite of monitoring activities by which SPS will receive and assess information about forecasted and real-time fire danger and fire weather conditions. Within this program, SPS is proposing four new activities: (1) Enhanced Meteorology Capabilities, (2) Weather and Fire Science modeling software, (3) Artificial Intelligence ("AI") Cameras, and (4) an updated Wildfire Risk Map in 2027. Through the activities proposed within this program, SPS will develop a greater understanding of wildfire risk within its service area that will allow it to invest in system maintenance, either through a future SRP or other investment vehicles, to make the system more resilient to wildfire risk.

[4] Moving forward, SPS anticipates the Wildfire Risk Map will continue to inform its wildfire mitigation activities by helping SPS optimize its spending on wildfire mitigation.

Q. Please describe the Enhanced Meteorology Capabilities activities.

A. Through the Enhanced Meteorology Capabilities activity, SPS proposes to install a network of weather stations in Tier 2 and Tier 3 wildfire risk areas and to locate those weather stations near SPS assets. The weather stations SPS is proposing to install are capable of monitoring real-time weather conditions such as air temperature, relative humidity, sustained wind speed and direction, and fuel moisture content. The weather stations record and communicate between 6 and 120 observations per hour. The weather stations will provide SPS invaluable real-time weather data, which SPS will then be able to use to inform its own weather forecasts and weather model validation. Because the weather stations are strategically located directly on utility poles, they will provide SPS more precise site-specific information than government or third-party weather monitoring networks can for the SPS system and adjacent property owners. SPS proposes to use this information to identify areas with high fire potential; trigger early warnings of fire; and inform decisions about equipment maintenance, power line de-energization, and targeted inspections. Additionally, by leveraging a network of these weather stations, SPS will gain a granular understanding of local weather patterns and be able to take proactive measures to prevent wildfires, even in the most remote regions of the service area.

Q. How many weather stations does SPS propose to install?

A. If the SRP is approved, SPS intends to install 110 weather stations in its Texas service area between years 2025 and 2028. SPS has used the Wildfire Risk Map tier designations to locate the weather stations.

Q. Please describe the Weather and Fire Science Modeling activity SPS proposes as a part of the Wildfire Situational Awareness program.

A. SPS proposes to use wildfire modeling technology that specializes in operationalizing fire science. SPS provides a detailed description of each of the modeling software programs it proposes within this activity in Section IV.E of its SRP. Generally, the modeling software's primary use is for modeling consequence for risk modeling and planning purposes. It advances fire spread modeling based on historic and asset data run millions of times to quantify consequence. It then outputs a distribution curve of consequence that allows SPS to make critical decisions on wildfire mitigation. This component of the Weather and Fire Science software is the FireSight package.

Q. How does SPS propose to use the data generated by the modeling software?

A. The wildfire modeling software SPS is proposing as a part of the Wildfire Situational Awareness measure supports the entire life cycle of wildfire protection planning, including fuel mapping, weather modeling, fire behavior analysis, custom risk model development, wildfire risk assessment, fuel treatment planning, and mitigation project implementation and tracking. This state-of-the-art fire behavior modeling software also allows visibility of the potential threat to assets, structures, and population centers. Additionally, the modeling software has built-in daily

monitoring tools and dashboards that provide SPS with updates regarding wildfire danger in high-risk asset areas that includes notifications to key decision-makers.

Q. Are there any other ways SPS proposes to use this modeling software?

A. Yes. The software also provides SPS the capability to identify risk across landscapes by evaluating weather, topography, fuels, historical wildfire occurrence, and utility outage data. This analysis helps to pinpoint where mitigation efforts can have the most impact and where the risk is greatest. Along with the suite of situational awareness tools, this information supports operational decisions to reduce wildfire risk.

Q. Has SPS received any grants to offset the software cost?

A. Yes, as a part of the Bipartisan Infrastructure Law, the United States Department of Energy's Grid Deployment Office is administering a Grid Resilience and Innovation Partnerships ("GRIP") federal funding program to improve the resilience of utility infrastructure against growing threats of extreme weather. SPS was allotted $7.3 million under this program to be used for the modeling software. If the SRP is approved, SPS is proposing to use these funds to offset costs to its customers.

Q. Please describe the AI Camera activity.

A. While SPS has taken an initial step to introduce AI Cameras to monitor its system, SPS is proposing to acquire and install significantly more AI Cameras to significantly increase coverage of its system. If the SRP is approved, SPS will position these additional AI Cameras in high-priority feeder areas within its service area.

The AI Cameras offer SPS, as well as first responders within SPS's service area who elect to receive this data, a continuously monitored 360-degree panoramic view of the coverage areas.[5] The AI Cameras use an algorithm that is constantly adjusting and evolving to help the Cameras become more accurate at detecting smoke. If smoke from any source is detected, notifications are sent to first responders, local offices of emergency management, and key decision-makers within SPS. The AI Cameras and related software SPS proposes to acquire and install are produced by a company called Pano. Pano has provided SPS a white paper explaining the functionality and effectiveness of its products. The Pano Whitepaper is attached to the SRP as Exhibit C.

Q. Please describe how the AI Camera software functions.

A. The software allows for continuous monitoring for real-time wildfire detection and alerts. High resolution cameras and 30-times optical zoom capability add to the detection and value. The AI algorithm has been trained on thousands of images and continues to improve and evolve.

Q. Please describe the Wildfire Risk Map.

A. The Wildfire Risk Maps are built and scheduled to be updated on a three-year basis. EDM prepared the current Wildfire Risk Map for SPS in 2024, and a new map will be necessary to address potential changes within the service area in 2027. SPS proposes that the cost of the 2027 Wildfire Risk Map be included in the SRP.

[5] The metal oxide semiconductor ("MOS") sensor in the camera is sensitive in the visible light range as well as the near-infrared range, which allows heat from a fire to be visible at night.

Q. Does SPS propose to use the activities within the Wildfire Situational Awareness Program in coordination with one another?

A. Yes. SPS's wildfire team will use modeling software and weather stations to identify the optimal locations for the AI Cameras. All of these technologies also aid SPS in assessing risk and making real-time decisions on distribution system protection in the event SPS's enhanced powerline safety settings ("EPSS") are activated as a part of the Distribution System Protection Modernization program. The SRP describes EPSS and the capabilities it provides SPS in detail in Section IV.B of the SRP.

2. Wildfire Physical Mitigation Program

Q. What is the Wildfire Physical Mitigation Program?

A. The Wildfire Physical Mitigation program is intended to address areas of the electrical system where SPS is vulnerable to wildfire risk associated with its facilities that would not require immediate maintenance, upgrade, or replacement under current SPS standards. In order to mitigate wildfire risk on a permanent basis, specific system resilience or hardening techniques, such as asset rebuilds or targeted undergrounding, would be deployed at a location. Through this measure, SPS is proposing to accelerate and/or increase work to address wildfire risk in Tiers 2 and 3. This measure promotes public safety and system reliability through programs that operate the electric system in a manner that helps reduce the risk of a utility asset causing an ignition.

Q. What activities does SPS propose as a part of the Wildfire Physical Mitigation Program?

A. SPS is proposing (1) Defensible Space Around Poles ("DSAP") for vegetation management, (2) wood substation conversions, and (3) transmission wildfire detailed inspections as this work is all incremental to the other wildfire mitigation work SPS currently executes.

Q. Please describe the DSAP activity.

A. The DSAP activity is a vegetation management program specifically designed to manage vegetation that may serve as fuel around transmission and distribution assets to reduce fire propagation. This activity will be preventative, as it involves establishing safe zones within a 10-foot radius and an 8-foot vertical area around power lines and their associated equipment thereby reducing the chances of ignition. This activity will be performed in Tiers 2 and 3 wildfire areas.

Q. Please describe the Wood Substation Conversion activity.

A. SPS proposes to remove the four wood substations in Tiers 2 and 3 wildfire areas and will implement distribution feeder level voltage conversions or step-downs at each site. In the existing wood substations, electric equipment and conductors are mounted to wooden structural members, while modern standards indicate use of steel for substations. These wood substations are nearing the end of their expected lifespan, and removing them now, rather than waiting for replacement under SPS's existing construction standards, provides an opportunity to more immediately make the SPS system more resilient to fire and high winds resiliency events, both of which are threats to the existing wooden structures.

Q. Please describe the transmission wildfire detailed inspections.

A. The transmission wildfire detailed inspections involve rigorous visual inspections of transmission lines and poles. The inspections will be conducted annually or biannually depending on tier classification in Tier 2 or Tier 3 wildfire areas. Through these inspections, SPS will have greater situational and operational awareness of system and asset conditions by consistent assessment of whether assets have been impacted by weather, storms, age or mechanical failures. This will allow SPS to make targeted improvements to the resiliency of its system.

C. Evidence of Effectiveness and Benefits of the Wildfire Mitigation measure

Q. What evidence does SPS have to suggest the Wildfire Mitigation measure will be effective?

A. The situational awareness and physical mitigation strategies like those proposed in the SRP as a part of the Wildfire Mitigation measure are activities that are widely utilized by other utilities—and approved by regulators—as part of Wildfire Mitigation Plans, as described by SPS witness Mr. Brockbank. Although a robust data set is not yet available to demonstrate the effectiveness of these programs, SPS's understanding of other utilities' experience is that these programs result in fewer wildfire ignitions and more rapid responses when wildfire occurs. Additionally, by using the Wildfire Risk Map to inform the areas of the system where the weather stations and AI Cameras should be located, SPS is targeting the key areas for wildfire mitigation and therefore maximizing the resiliency benefit.

Q. How is the Wildfire Mitigation measure expected to benefit the resiliency of the SPS system?

A. The programs within the Wildfire Mitigation measure are expected to provide many of the benefits the PUCT has identified in Rule 25.62(c)(2)(iii). Namely, the measure is expected to (1) reduce the frequency and duration of outages for customers resulting from damaged utility equipment and improve the overall service reliability for customers by reducing the risk of wildfire ignition and (2) provide data to allow for more prompt wildfire fighting and, once fire conditions subside, equipment repair.

D. Implementation

Q. How does SPS propose to implement the Wildfire Mitigation measure?

A. SPS witness Casey Meeks describes SPS's systematic approach for implementing its SRP. To implement the Wildfire Mitigation measure in particular, SPS will work with vendors of the weather stations, AI Cameras, and modeling software to procure the software and equipment identified in the measure. As with the other measures in the SRP, SPS will then use its partner vendors, internal resources, or full Engineering Procurement and Construction ("EPC") contracts to deliver programs in the Wildfire Mitigation measure through to execution. SPS will work with the larger Xcel Energy organization to define the parameters for each program within the Wildfire Mitigation measure, including managing labor, setting and tracking milestones, and ultimately execution of each program. The SRP provides cost estimates for implementation of the Wildfire Mitigation measure in Section IV.E.

Q. What is the timeline for completing the Wildfire Mitigation measure?

A. SPS proposes to conduct work in the Wildfire Mitigation measure throughout the SRP period. Work will begin in 2025 and continue through 2028.

Q. What are the costs associated with implementation of the Wildfire Mitigation measure?

A. Table AZS-1 summarizes the estimated costs associated with implementing the Wildfire Mitigation measure. The cost drivers relevant to these estimates are detailed in the scope of work in SPS's SRP Measure Programs Summary, included as Attachment B to the SRP. The scope of work detailed in this summary includes the estimated equipment, frequency of inspections, and other activity that are the cost drivers behind these estimates.

Table AZS-1: 2025-2028 SRP Wildfire Mitigation Measure Capital and O&M

	2025		2026		2027		2028		Total Plan	
	Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M
Wildfire Mitigation	$2.5M	$2.3M	$7.2M	$4.3M	$8.3M	$4.9M	$1.5M	$4.0M	$19.7M	$15.5M

Q. Are the cost estimates for the Wildfire Mitigation measure reasonably likely to be accurate?

A. SPS is confident in its cost estimation process, based on historical projects of similar scale, industry knowledge, collaboration with its vendors, and understanding of reasonably anticipated supply-chain pressures. SPS is also able to benefit from Xcel Energy's enterprise-wide attention to wildfire mitigation and its broader experience in different operating utilities with activities like those proposed in the Wildfire Mitigation measure. For instance, SPS anticipates it will use some of the same vendors that currently serve PSCo in implementing its

Wildfire Mitigation Plan. Additionally, as a project is ongoing, SPS routinely updates cost estimates based on institutional knowledge of supply chain constraints, inflation, and other market pressures that impact the price of materials and labor it sources.

E. System Coordination

Q. Will implementation of the Situational Awareness program require any system outages?

A. No, none of the situational awareness programs require outages or necessitate switching.

Q. Will implementation of the Physical Mitigation program require transmission system outages?

A. No. The transmission detailed visual inspections will not require any transmission outages, nor will the other activities in the program.

Q. Will the Wildfire Mitigation measure implementation require SPS to coordinate with any government entities or programs?

A. Operationally speaking, generally no. SPS coordinates with government entities in its normal course of business, for compliance, permitting, or other regulatory reasons. As discussed above, SPS does anticipate using GRIP funding for the modeling software proposed as a part of the Wildfire Situational Awareness program.

Additionally, the Wildfire Mitigation measure does create opportunities for collaboration with emergency response managers and volunteer wildfire departments in the SPS service area. In particular, the data collected through the AI

Camera program will be made available to those fire departments who choose to participate.

F. Metrics

Q. What metrics will SPS use for evaluating the effectiveness of the Wildfire Mitigation measure?

A. SPS proposes two quantitative metrics to evaluate the effectiveness of the Wildfire Mitigation measure. First, SPS proposes to calculate the number of units identified and completed in Tiers 2 and 3 for DSAP compared to the plan ("Units Completed in DSAP"). Second, SPS proposes to calculate the detailed inspections executed in Tier 2 and Tier 3 wildfire areas, with associated number of emergency and high-priority defects identified and remediated ("Transmission Inspections").

Q. Why is the Units Completed in DSAP metric appropriate for evaluating the effectiveness of the Wildfire Mitigation measure?

A. The DSAP program prevents sparks from becoming active ignition and causing a wildfire. DSAP progress prioritized in the moderate and high-risk Tiers 2 and 3 wildfire areas will be valuable in advancing the resilience of the SPS system.

Q. Why is the Transmission Inspections metric an appropriate metric for evaluating the effectiveness of the Wildfire Mitigation measure?

A. The number of detailed inspections executed in Tiers 2 and 3 wildfire areas will demonstrate program progress and ensure the durations of defects on the system are limited. The tracking of emergency and high-priority defects identified and remediated provides two useful elements of evidence of effectiveness. First, by capturing the cumulative number of defects identified and remediated, it will demonstrate the efficacy of the inspection program itself in reducing the number of

vulnerabilities particularly susceptible to resiliency events. Second, the number of defects identified and remediated should have an overall decreasing trend over time. It is important to note, however, that there are exogenous events—particularly including resiliency events—that could cause defects that would be found in subsequent inspections and cause increases in the number of defects. SPS will report and characterize the trends under this metric.

G. Distinguishing SPS's Existing Wildfire Resiliency Activities

Q. What is the purpose of this section of testimony?

A. In this section, I distinguish SPS's activities in SPS's SRP-proposed Wildfire Mitigation measure from related SPS activities, consistent with Rule 25.62(c)(3)(D).

Q. Does SPS have existing activities or programs related to those proposed in the SRP?

A. Yes. There are several related existing activities or programs. First, SPS has existing vegetation management and inspection programs. Second, in late 2024, SPS initiated the planning process for the installation of AI cameras. Installation of cameras not accounted for as a part of the proposed SRP budget has begun and will continue through 2025. Third, a wildfire risk map was completed in 2024 to identify areas with the highest wildfire risk, influencing the work planning within the SRP.

Q. How do the programs proposed as a part of the Wildfire Mitigation measure differ from these programs?

A. First, as noted, SPS currently has a vegetation management program and conducts inspections of lines; however, the frequency and locations of these inspections vary significantly. The current vegetation management plan operates on a cyclical interval of five to seven years. In contrast, the DSAP program proposed in the SRP would involve annual clearing of vegetation and grasses in areas of heightened wildfire risk. SPS currently inspects all transmission assets every four years. The proposal in the SRP aims to increase focus on Tiers 2 and 3 with inspections occurring on an annual and biannual basis. SPS has identified what is incremental.

Second, as to the AI cameras, the SRP would constitute an expansion of that effort, and existing versus incremental investments are clearly distinguishable.

Finally, SPS's proposal to develop an updated Wildfire Risk Map in 2027 is incremental and clearly distinguishable from the development of the existing map.

H. Alternatives

Q. Has SPS considered reasonable and readily available alternatives to the Wildfire Mitigation measure?

A. Yes. SPS considered multiple alternatives to the wildfire mitigation measure. Namely, SPS considered (1) undergrounding for wildfire mitigation and (2) maintaining its current wildfire programming, as described above, at the current pace of investment.

Q. Why were the alternatives not selected as measures under this SRP?

A. Widespread (distinct from targeted) undergrounding is not a cost-effective alternative because of the high cost per mile, as SPS witness Brianne Jole discusses in greater detail. Simply maintaining current programs is also not a viable alternative because it would not allow SPS to respond to the increasing resiliency threats and needs of its customers; nor would doing so be consistent with the objectives reflected in the SRP statute and Rule 25.62, which I understand are intended to encourage utilities to examine their system and look for ways to make targeted meaningful improvements to the system to enhance resiliency specifically and in addition to any existing programming. As the SRP explains, the increasing risks of wildfire in the SPS service area necessitate more robust wildfire mitigation than under current programs. One example is replacing the wood substations in high wildfire risk areas now, rather than on an end-of-life replacement timeline, as would be recommended under existing SPS programming. Accordingly, SPS is proposing to make incremental investments that will improve the resiliency of its system.

IV. CONCLUSION

Q. Do you have any final comments or recommendations for the PUCT to consider related to the Wildfire Mitigation measure?

A. Wildfire mitigation is a critical component of system resiliency. Employing wildfire mitigation tools and distributing them in the highest risk wildfire areas of SPS's territory is reasonably calculated to improve resiliency for the SPS system for the benefit of its customers. All proposed wildfire mitigation measures should be approved and included in the SRP.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF COLORADO)
)
COUNTY OF DENVER)

ANNE Z. SHERWOOD, first being sworn on her oath, states:

I am the witness identified in the preceding testimony. I am over 18 years of age, of sound mind, and am capable of making this affidavit. I have read the testimony and the accompanying attachments and am familiar with the contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

Anne Z Sherwood
ANNE Z. SHERWOOD

Subscribed and sworn to before me this 27th day of December 2024 by ANNE Z. SHERWOOD.

Holly A. Mashburn
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20214014663
MY COMMISSION EXPIRES April 13, 2025

Holly Mashburn
Notary Public, State of Colorado

My Commission Expires: 4/13/25

DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	§ § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY
of
RYAN BROCKBANK

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

*(Filename: BrockbankRBD*irect.docx; *Total Pages:19*)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
CEATI	Centre for Energy Advancement Through Technological Innovation
EDM	EDM International, Inc.
HFA(s)	Hazardous Fire Area(s)
RPS	Risk to Potential Structures
SPS	Southwestern Public Service Company, a New Mexico corporation
SRP	System Resiliency Plan
T&D	Transmission and Distribution
UAA	Utility Arborist Association
WMP	Wildfire Mitigation Plan
WRO	Wildfirerisk.org
Xcel Energy	Xcel Energy Inc.

DIRECT TESTIMONY
OF
RYAN BROCKBANK

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ryan Brockbank. My business address is 4001 Automation Way, Fort Collins, Colorado 80525.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") and wholly owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by EDM International, Inc. ("EDM"), where I currently serve as a Principal.

Q. Please briefly outline your responsibilities as a Principal at EDM.

A. I am responsible for EDM's utility right-of-way services, including utility wildfire risk mitigation, vegetation management, and system resiliency consulting.

Q. Please describe your educational background.

A. I have a Bachelor of University Studies in Environmental Studies from the University of Utah and a Master of Science in Environmental Management from the University of San Francisco.

Q. Please describe your professional experience.

A. I have over 30 years of experience in the areas of professional field services operations management, utility vegetation management consulting, environmental

assessment services, asset management, remote sensing, system resiliency, and utility wildfire mitigation strategies.

Specific to wildfire mitigation consulting, I have acted in an advisory capacity to the State of California's Wildfire Safety Advisory Board and have collaborated with numerous transmission and distribution ("T&D") electric and gas utilities (investor-owned utilities, rural electric cooperatives, and municipal utilities), a United States federal transmission and generation power marketing administration, an independent T&D operator, and various government representatives on the strategic development and tactical implementation of:

- Wildfire mitigation plans;
- Asset-based hazardous fire area risk assessments and mapping;
- Escalating wildfire situational awareness strategies;
- Ignition management programs;
- Public safety power shutoff plans;
- Fuels management;
- Asset hardening;
- Grid resiliency; and
- Performance monitoring and continuous improvement.

I previously served as President of Western ECI and Chief Operating Officer of ECI, two of the nation's largest utility vegetation management consulting service providers, assisting utilities in successfully and sustainably managing their infrastructure and natural resources. I was responsible for leading the strategic and tactical direction of field operations, including safety, business performance, human resources, fleet, and employee training for over 500 field personnel.

I also have extensive experience working on various electric utility and pipeline consulting and related activities, including:

- Distribution line clearance studies;
- Transmission rights-of-way studies;
- North American Electric Reliability Corporation compliance;
- Integrated vegetation management;
- Environmental impact studies;
- Right-of-way stewardship;
- Quality control management services; and
- Professional training services.

I was a principal investigator on the recent Centre for Energy Advancement Through Technological Innovation ("CEATI")-sponsored[1] project, "Mitigating Risks Associated with Distribution Overhead Systems and Wildfire." The project report is unique in the industry and documents utility wildfire mitigation practices for catastrophic wildfire ignition prevention and asset protection. I have also served as a Director of the Utility Arborist Association ("UAA") and am currently Chairperson of the UAA Environmental Stewardship Committee. I am also an International Society of Arboriculture Certified Arborist.

Q. Have you testified before any regulatory authorities?

A. No.

[1] CEATI is a solution-driven network for power industry professionals. CEATI provides its members with practical research, expert guidance, and forums for knowledge exchange.

II. WILDFIRE RISK ASSESSMENT, MITIGATION, AND MAPPING

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to discuss EDM's engagement by SPS as a third-party expert in wildfire risk assessment and mitigation, supporting SPS's efforts through the development of geospatial wildfire risk mapping of its service territory. I also address the consistency of SPS's wildfire-related measures that are part of its System Resiliency Plan ("SRP"), along with its overall Wildfire Mitigation Plan ("WMP"), with the practices of other leading utilities.

Q. Please describe the risk of wildfire in SPS's service territory.

A. As described in section III (B) of the SRP, SPS operates in fire-prone areas of Texas. Data and history demonstrate that SPS and the communities it serves are exposed to potentially catastrophic wildfires due to emerging threats associated with the increased frequency of wildfire weather and wildfire danger conditions, aging infrastructure, and increased development in wildland areas. The recent Texas Panhandle fires are indicative of these conditions and threats.

SPS's service territory is located in climate zones experiencing significantly increased wildfire weather conditions over the last 50 years, with the vast majority of its Texas service territory experiencing an average annual increase of 34 more fire weather days as compared to 1973.[2] Fire weather is defined as the combination of three meteorological conditions supporting the spread of wildfire, including high

[2] Climate Central. Average Annual Fire Weather Days by Climate Division. 2024. https://www.climatecentral.org/graphic/longer-more-intense-fire-weather-seasons?graphicSet=Average+Annual+Fire+Weather+Days+by+Climate+Division&location=AZ+-+Tucson+(Southeast)&lang=en

sustained winds, high ambient air temperatures, and low relative humidity. Analysis of acreage burned in Texas indicates a significant increase in the number of acres burned by wildland fires over the previous four years, which is consistent with national historical acres burned data. Wildfire risk varies across SPS's geographic service territory depending on the fuels, terrain, fire behavior patterns, prevailing weather patterns, proximity of developed areas, and other factors.

Q. How has SPS sought to better understand and address the variations in wildfire risk across its service area?

A. SPS engaged EDM to develop a geospatial wildfire risk map specific to its service territory to better understand its landscape wildfire risk relative to developed areas and its assets, and thereby support prioritization and implementation of SPS's wildfire mitigation programs and activities. The results of this effort are described in more detail in my testimony and in section IV(G)(2) of the SRP under the Situational Awareness program of SPS's Wildfire Mitigation measure.

Q. How has SPS approached wildfire risk mapping as part of its SRP?

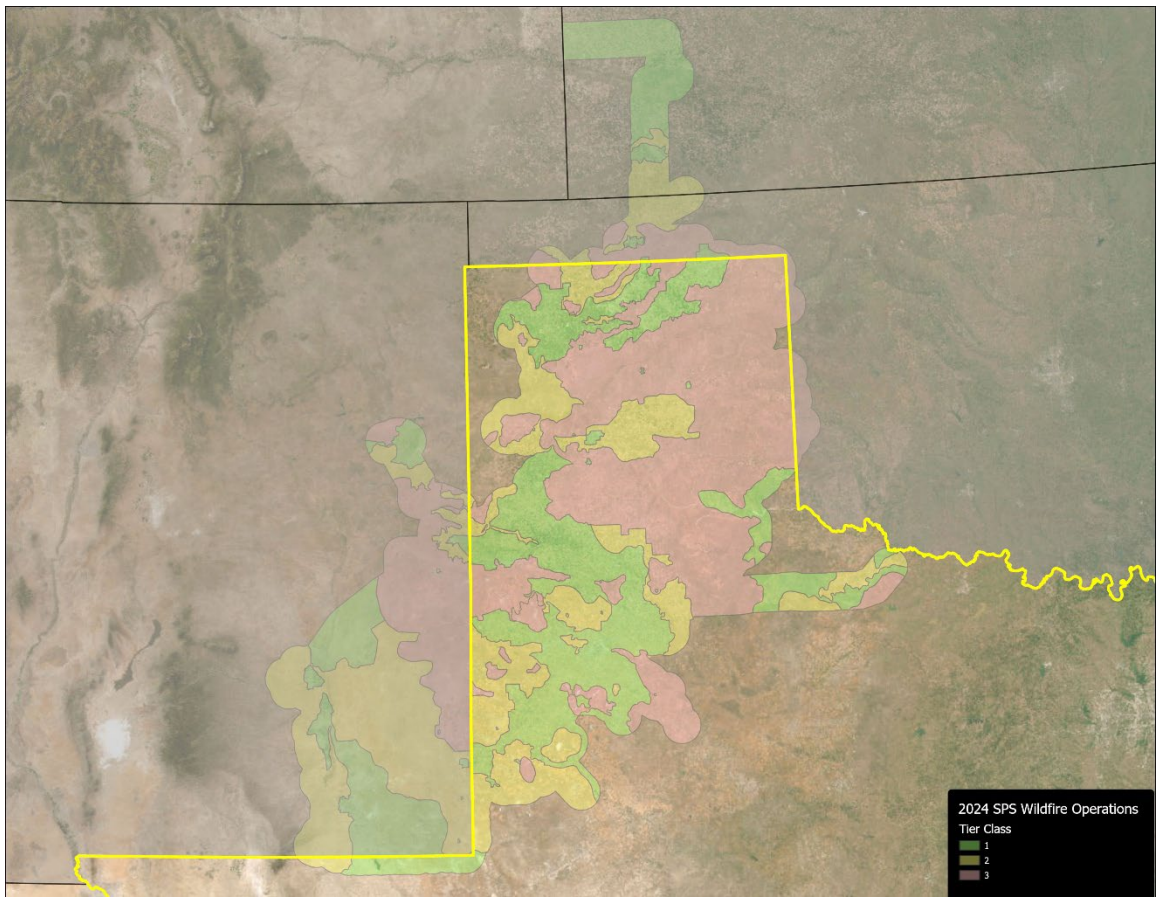
A. For this SRP, SPS retained EDM to create four geospatial Wildfire Risk Map outputs specific to SPS's Texas and New Mexico service territory to facilitate understanding of its fire risk on the landscape and help prioritize its various wildfire mitigation efforts, including efforts specific to its Texas service territory proposed in this application. SPS's SRP includes descriptions of these various map outputs, including:

1. Hazardous Fire Areas ("HFAs"): A fundamental and more granular geospatial representation of landscape/population wildfire risk split into six risk classifications.
2. Fire Tiers: Aggregated from the six HFAs, the four Fire Tiers represent a broader visualization of landscape/population wildfire risk.
3. Operational Tiers: An interim output that interprets and further aggregates the more granular Fire Tiers into three larger risk polygons.
4. Wildfire Operations Map: The product of landscape/population fire risk informed by broad utility infrastructure and corresponding asset locations to create three contiguous wildfire risk tier polygons: Tier 1 (lower risk), Tier 2 (moderate risk), and Tier 3 (higher risk).

The Wildfire Operations Map[3] can be more easily interpreted to assist SPS with the prioritization and implementation of wildfire risk mitigation resources. Figure RB-1 below represents SPS's Wildfire Operations Map and provides a regional snapshot of SPS's landscape/population wildfire risk categorization across its service territory including those extending beyond the Texas service territory footprint.

[3] In general, the terms Wildfire Risk Map and Wildfire Operations Map are used interchangeably in direct testimony and in the SRP.

Figure RB-1: Wildfire Operations Map – SPS Service Territory



Q. Please explain the data sources used to develop the Wildfire Risk Map outputs.

A. The baseline datasets used to develop the HFAs and other Wildfire Risk Map outputs are available from wildfirerisk.org ("WRO").[4] HFAs served as the foundational layer of the three Operational Tiers and Wildfire Operations Map and provide granular insight into the relative wildfire hazards across the landscape relative to populated areas with developed assets. HFAs are geospatial representations of landscape/population wildfire risk based on an analysis of

[4] Source data was pulled from *Wildfire Risk to Communities,* U.S. Department of Agriculture and U.S. Forest Service, https://wildfirerisk.org.

relative potential for high-intensity wildfire on the landscape and considering factors such as potential for high flame length and potential risk to structures or homes.

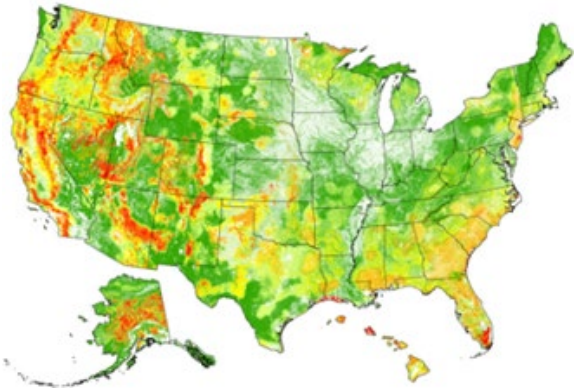
The baseline data was created by the United States Department of Agriculture Forest Service at the direction of Congress for the purpose of providing guidance and informing wildfire mitigation prioritization.

The WRO is built from nationally consistent data and uses industry-recognized data sources, including vegetation cover and fire-behavior fuel models, topography, historical weather patterns, and long-term simulations of large wildfire behavior. It is based on techniques developed by the Missoula Fire Sciences Laboratory of the Rocky Mountain Research Station. Baseline data informing the model include, but are not limited to, vegetation cover and fire-behavior fuel models from the interagency LANDFIRE program, which leverages the Scott and Burgan 40 Fire Behavior Fuel Models; topographic data from the United States Geological Survey; historical weather patterns from the National Weather Service; long-term simulations of large wildfire behavior from the USFS; and community data from the United States Census Bureau and Department of Energy.

Q. Please describe the baseline datasets used to develop the Wildfire Risk Map outputs.

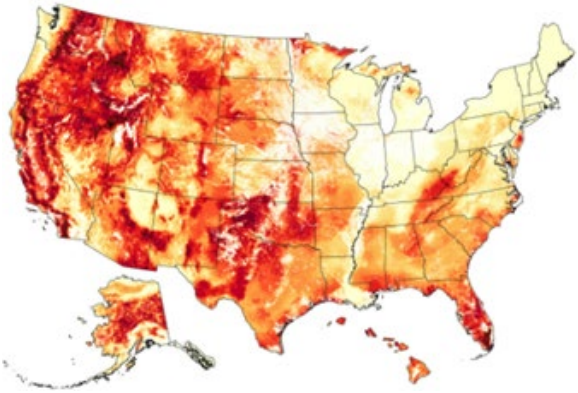
A. To develop the risk tiers of the Wildfire Risk Map outputs, EDM used several datasets, including Wildfire Hazard Potential, Burn Probability, Conditional Flame Length, Risk to Potential Structures or Risk to Homes, and Housing Unit Risk. In Figures RB-2 through RB-6 below, I provide a visual of each dataset and summarize what each dataset measures.

Figure RB-2: Wildfire Hazard Potential



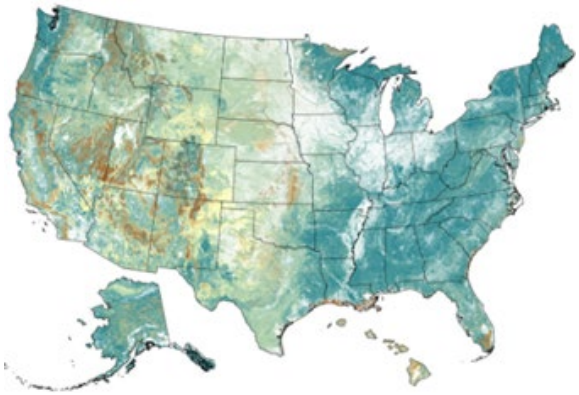
Wildfire Hazard Potential: An index that quantifies the relative potential for high-intensity wildfire that may be difficult to manage that serves as a measure to help prioritize where fuel treatments may be needed.

Figure RB-3: Burn Probability



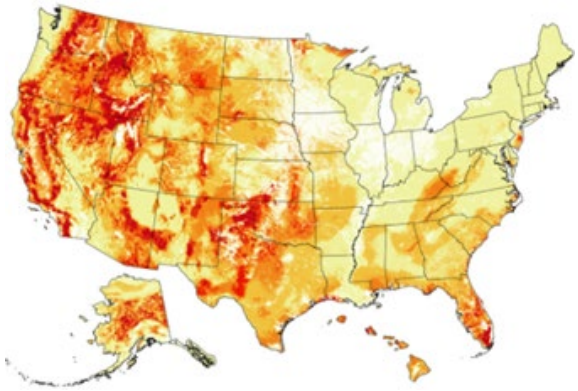
Burn Probability (or Wildfire Likelihood): The annual probability of wildfire burning in a specific location.

Figure RB-4: Conditional Flame Length



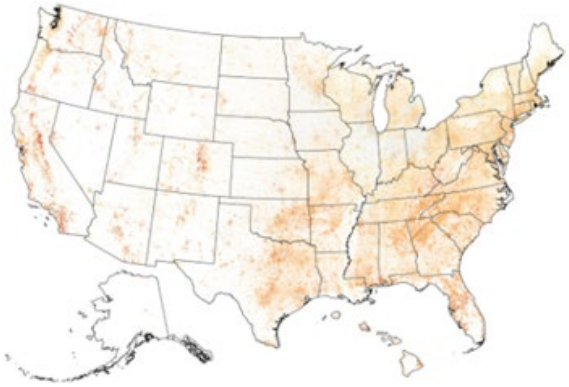
Conditional Flame Length: Most likely flame length expected at a given location if a fire occurs, based on all simulated fires that serves as a measure of wildfire intensity.

Figure RB-5: Risk to Potential Structures



Risk to Potential Structures ("RPS") (or Risk to Homes): A measure that integrates wildfire likelihood and intensity with generalized consequences to a home on every pixel. For every place on the landscape, it poses the hypothetical question, "What would be the relative risk to a house if one existed here?"

Figure RB-6: Housing Unit Risk



Housing Unit Risk: An index that integrates all four primary elements of wildfire risk, i.e., likelihood, intensity, susceptibility, and exposure, on pixels where housing unit density is greater than zero. It is conceptually similar to RPS, but also incorporates housing unit count.

Q. Please describe the key features of the Wildfire Risk Map outputs.

A. In addition to the Tier polygons, the Wildfire Risk Map outputs provide a landscape view of wildfire hazards, including a weighted evaluation of wildfire and population risk to match local variables for SPS's service area and its assets. It was designed strictly for utility purposes and is localized specific to SPS's assets, including overhead transmission and distribution lines, substations, generation sites, and communications sites. The Wildfire Risk Map outputs encompass a 10-mile buffer on both sides of the centerline for linear facilities (i.e., T&D lines) and around other SPS assets to provide a wider view of the surrounding areas that could potentially be impacted by fire on the landscape and provides defined weighted value class risk ratings. The Wildfire Risk Map outputs leverage quality, publicly available, vetted data that is curated from various government agencies and private sources. The Wildfire Risk Map outputs also provide a versatile and flexible data repository with the ability to change layers and add data to refine analyses.

Q. What is the purpose of the Wildfire Operations Map and tiered risk zones?

A. The Wildfire Operations Map and tiered risk zones or polygons rank areas based on wildfire risk on a service territory-wide basis. The tiers are references that support multiple activities and functional areas to provide guidance on which areas could be prioritized for risk mitigation. The tiers designate areas within SPS's service territory that are susceptible to high intensity, severe wildfire behavior and potential damages should a wildfire originate or burn in the vicinity. The tiers are foundational for prioritization of multiple activities. They provide important

guidance as SPS develops mitigations for utility-caused ignitions and improving asset protection and system resilience to outside wildfire threat. Under the SRP, most of SPS's wildfire mitigation work will be focused in Tiers 2 and 3. For example, most of SPS's transmission assessments and programs will be deployed throughout Tier 2 and Tier 3 areas, as will SPS's Defensible Space Around Poles program.

SPS has already made a concerted effort to adopt a mix of industry-recognized wildfire mitigation practices, such as pole inspection and repair/replace programs, transmission line inspections, vegetation management, and adjusting system operations settings during periods of escalating wildfire weather conditions.

It is important to note that the wildfire mitigation items proposed in the SRP do not stand on their own but complement and strengthen other plans and activities that SPS has implemented as part of its WMP that are not included in the SRP. SPS's Wildfire Operations Map is important to guiding SPS regarding where it should prioritize and execute the SRP and WMP activities based on the landscape wildfire risk relative to populated areas with developed assets and SPS facilities.

Q. How does SPS plan to use its new Wildfire Operations Map going forward under the SRP?

A. The Wildfire Operations Map helps SPS identify areas of the highest wildfire risk in its service territory. Operationally, the map provides SPS with guidance for program implementation, work prioritization, and resource allocation to help direct various programs within the wildfire risk tiers, such as vegetation management and inspections which have different requirements based upon the tier where the work

is to be performed. The Wildfire Operations Map also helps to identify those higher wildfire risk areas where various field work activities cannot be performed during periods of escalated or extreme fire weather conditions (e.g., Red Flag Warning days). For example, welding activities could be restricted and delayed until the period has passed.

Q. What are the risk mitigation and operational benefits of SPS's Wildfire Operations Map?

A. The Wildfire Operations Map has three contiguous wildfire risk tier polygons providing geospatial reference to operations teams regarding where the areas of higher and lower wildfire risk are located in and around SPS's service territory. All current assets, including overhead transmission and distribution lines, substations, generation sites, and communications sites are located within a wildfire risk tier. For areas of new construction or growth located within the 10-mile buffer of existing assets, the wildfire risk tier can be determined for that area, thus supporting SPS's consideration and implementation of the appropriate planning, siting, engineering, construction, and/or mitigation work to be performed. The Wildfire Operations Map includes tiers that are larger and more contiguous than the HFAs and Fire Tiers and therefore can be more easily interpreted for operational and prioritization decision-making purposes. The map is intended to enhance operational efficiencies and facilitate risk-based operational decisions by asset and/or circuit. As such, homogenous areas of risk categorization were demarcated

for circuits and facilities to be assigned and grouped within individual tiers to provide consistency for operational decisions.

SPS has operationalized the map so that, as much as possible, tier boundaries do not begin and/or end in the middle of a circuit or line. Breaks in the tiers were demarcated first by wildfire risk (capturing similarly dense areas of risk together) and second by logistic or intuitive breaks in the system, terrain, urban development, and/or public infrastructure (e.g., roads).

Q. How often does SPS plan to update the Wildfire Risk Map outputs?

A. Given that SPS's Wildfire Risk Map leverages publicly available, high-quality, vetted data that is curated from various government agencies and private sources, SPS plans on making updates to the Wildfire Risk Map outputs approximately every three years to continuously improve the wildfire risk map outputs as new data become available and SPS's wildfire risk mitigation efforts evolve and mature over time.

Q. Are the wildfire mitigation programs and activities included in SPS's SRP consistent with prevalent utility industry wildfire mitigation practices?

A. EDM's team has decades of experience assessing utility wildfire risk and evaluating, developing, and implementing enterprise utility wildfire mitigation programs and supporting cross-functional mitigation activities. In EDM's opinion, the wildfire mitigation programs and activities included in SPS's proposed SRP and the current WMP are consistent with prevalent utility wildfire mitigation practices employed by other leading utilities mitigating potential sources of ignition and protecting electrical facilities against possible wildfires. While EDM is not aware

of vetted publicly available studies with quantitative data on the effectiveness of wildfire mitigation programs, utilities operating in fire-prone areas rely on the successful implementation of many of the practices included in SPS's WMP and SRP. Public utility commissions that regulate these same utilities also expect and, in some cases, require many of these practices to be included in utility WMPs. Consistent with good utility practice, it is EDM's understanding that the programs, technologies and practices comprising SPS's WMP and the SRP Wildfire Mitigation resiliency measure are intended to be dynamic and evolving and that SPS will monitor and track mitigation performance using the various metrics described in the SRP to evaluate the benefits of this multi-year SRP effort and to identify and act on the relevant trends. EDM agrees with this approach.

Q. Does this conclude your direct testimony?

A. Yes.

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

AFFIDAVIT

STATE OF CALIFORNIA)
)
COUNTY OF ALAMEDA)

RYAN BROCKBANK, first being sworn on his oath, states:

I am the witness identified in the preceding testimony. I am over 18 years of age, of sound mind, and am capable of making this affidavit. I have read the testimony and the accompanying attachments and am familiar with the contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

RYAN BROCKBANK

Subscribed and sworn to before me this 21st day of December 2024 by RYAN BROCKBANK.

Notary Public, State of California

TODD P. CONNORS
COMM. # 2473470
NOTARY PUBLIC - CALIFORNIA
ALAMEDA COUNTY
COMM. EXPIRES DEC. 19, 2027

My Commission Expires: 12-19-2027