BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF GEVO NET-ZERO 1, LLC TO HAVE KINGSBURY ELECTRIC COOPERATIVE, INC. ASSIGNED AS ITS ELECTRIC PROVIDER IN THE SERVICE AREA OF OTTER TAIL POWER COMPANY	* * * * * * * *	**EAST RIVER ELECTRIC POWER COOPERATIVE, INC.'S ANSWERS TO FIRST SET OF DATA REQUESTS TO EAST RIVER ELECTRIC POWER COOPERATIVE INC.**

East River Electric Power Cooperative, Inc. ("East River") submits the following answers and responses to Staff's First Set of Data Requests to East River:

1-1) Please provide a copy of all data requests East River received from any party and East River's responses to the data requests. This should be considered a continuing request.

Ok.

1-2) Please identify Gevo Net-Zero 1, LLC's (NZ1) contracted minimum demand that Kingsbury Electric Cooperative (KEC), East River, and Basin Electric Cooperative (Basin) will serve. Provide a copy of any document that legally binds NZ1 to meet that minimum demand service requirement.

Answered by Mark Hoffman, East River Electric Power Cooperative, Inc.'s Chief Operations Officer:

The document that binds NZ1 is the Electric Service Agreement ("ESA") entered into between NZ1 and KEC. It is our understanding that a redacted and confidential version of the executed ESA will be filed by NZ1. The ESA requires KEC to supply NZ1's electric demand not to exceed 49MW which satisfies the "contracted minimum demand". Notwithstanding satisfaction of the "contracted minimum demand" requirement by the ESA, East River consents to an amendment to the ESA to include the following provision:

> *Minimum Demand. Notwithstanding the Customer's requirements for kW demand or use of kWh energy, the demand for billing purposes hereunder shall be not less than 2,000 kW for any billing period.*

KEC and NZ1 have agreed in principle to this amendment.

1-3) In its Petition, NZ1 states the facility "will have firm, electric demand of approximately 40-45 MW, with a 90% load factor" and that the facility "will have a coincidence factor of 95%" at the time of the East River/KEC peak.

a) How much firm capacity is Basin and East River planning for to reliably supply NZ1?

Answered by Mark Hoffman:

The entire load. Basin is not a party to this proceeding. This answer and any other question regarding Basin is based on East River's information and belief.

b) What is Basin's current capacity position and reserve margin?

Answered by Mark Hoffman:

According to the 2024 SPP Resource Adequacy Report Basin has a total capacity of 4,216 MW, a net Peak Demand of 3,482.4 MW, a resource adequacy requirement of 4,004.7 MW and an excess capacity of 211.3 MW resulting in a LRE planning reserve margin of 21.1%. See page 17 of the report. A hyperlink to the report is provided below.

https://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf

c) What effect will KEC's provision of service to NZ1 have on Basin's capacity position and reserve margin?

Answered by Mark Hoffman:

It will decrease by the coincident demand of NZ1.

d) How will Basin fulfill NZ1's demand and energy requirements?

Answered by Mark Hoffman:

Basin generation and/or market purchases.

e) Will Basin need to procure or construct additional capacity to cover the NZ1 demand?

Answered by Mark Hoffman:

Not to our knowledge.

f) If additional capacity needs to be procured or constructed, will NZ1 pay the incremental cost of that capacity or a system rate after rolling those costs in with existing rate base? Please explain.

Answered by Mark Hoffman:

Capacity charges are included in Basin Electric's rates for demand and energy.

1-4) Provide CAIDI, SAIDI, and SAIFI reliability index data for the portion of East River's system that would serve NZ1's load. Also provide a report of outages that would have affected NZ1 over the last three years.

Answered by Mark Hoffman:

The table below reflects the reliability index data for the East River transmission system. East River does not calculate these based on a certain area or region but rather our entire system. The numbers in the table reflect a 3-year running number so the 2023 numbers include data from Jan 1, 2021, to Dec 31, 2023.

YEAR	***SAIDI***	***CAIDI***	***SAIFI***
2021	*51.04*	*44.79*	*0.56*
2022	*25.87*	*48.28*	*0.54*
2023	*23.16*	*56.49*	*0.41*

East River does not have reports of outages for this location and/or the contemplated transmission configuration that would have affected NZ1 in the last three years.

1-5) Refer to Exhibit 5 of NZ1's Petition and NZ1's response to Staff data request 1-2(b).

a) Provide a list of the transmission facilities East River would move forward with and construct if KEC does not serve NZ1's load.

Answered by Mark Hoffman:

[Trade Secret Data Begins]

[Trade Secret Data Ends]

1-6) Does East River, Basin, or SPP need to perform any studies on the proposed large load addition to East River's transmission system? If yes, please identify what studies have been completed, or will need to be completed, and the timeline for those studies.

Answered by Mark Hoffman:

Yes. East River completed a load connection transmission system study which was completed on November 1, 2023 and is attached marked as Exhibit 1. The load was included in SPP's 2024 Integrated Transmission Planning (ITP) assessment. SPP identified the needs resulting from the loads and solicited upgrades from stakeholders to mitigate the needs. East River submitted its proposed upgrades which SPP evaluated against other options but ultimately selected the East River proposed upgrades as the best solution. The draft copy of the SPP study as submitted to the SPP Markets and Operations Policy Committee (MOPC) is attached and marked as Exhibit 2. This is the version as posted on October 7, 2024. The study report and associated system upgrades are being reviewed by stakeholders and will be on the October meeting agenda of the SPP Board of Directors for their review and approval.

1-7) Has SPP, Basin, or East River conducted any studies to determine if the NZ1 large load addition has an impact on SPP transmission congestion costs? If yes, please summarize the results of the studies and provide a copy of the studies. If no, identify the studies that will be completed, if any, to assess the large load addition's impact on the transmission system.

Answered by Mark Hoffman:

The evaluation of congestion costs requires the use of special software that East River and Basin do not own. Transmission system congestion is addressed through the market economic analyses performed by SPP during the ITP assessments. The study report and associated system upgrades are being reviewed by stakeholders and will be on the October meeting agenda of the SPP board of directors for their review and approval. See 1-6.

1-8) Has SPP, Basin, or East River conducted any studies to determine if the NZ1 large load addition has an impact on flowgates used, or would be used, in market-to-market coordination under the MISO/SPP Joint Operating Agreement? If the answer is yes, please provide a summary of the study results and provide a copy of the study. If the answer is no, identify the studies that will be completed, if any, to assess the impact the large load addition would have on market-to-market coordination.

Answered by Mark Hoffman:

SPP, in their NERC defined roles as Planning Coordinator and Reliability Coordinator for the SPP region, performs the system capability assessments and calculations, monitors and establishes flowgates, and performs congestion management. SPP performs the system studies and flowgate assessments on a periodic basis. SPP is also responsible for market-market coordination between SPP and MISO.

East River and Basin do not study impact on flowgates.

1-9) On page 11 of NZ1's Petition, it is stated that "the Commission can be assured that the rates KEC will charge NZ1 and DRH are sufficient to recover its costs associated with serving the load."

a) Please provide any data East River has in its position that could be used at hearing to support the statement above.

Answered by Scott Shewey, East River Chief Financial Officer:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence. The legislature has not delegated the Commission with authority to regulate the electric rates of electric cooperatives.

Without waving said objection, NZ1 and DRH intend to purchase power from KEC via a large load rate. The large load rate recognizes the competitive nature of large end use loads while recovering power supply and investment costs associated with these loads. The rate is set at power supply cost plus other system costs, which recovers maintenance, administrative expenses, and other system-wide costs. The large load rate is subject to periodic review by the KEC Board of Directors and can be modified to reflect the cost. The members of KEC elect those that represent them and manage their system. Thus, those customers have a voice in their service and its oversight.

b) What effect, if any, will KEC serving NZ1 have on KEC's existing customers' rates, East River's existing customers' rates, and Basin's existing customers' rates?

Answered by Scott Shewey:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waving said objection, East River and KEC rates are designed to recover costs directly associated with the load and system-wide shared costs. Adding a load of this size will decrease the system cost recovery on other rate classes.

c) Will the margin on NZ1's sales offset any additional costs that existing customers may incur due the large load addition? Please provide any data and calculations supporting the response given.

Answered by Scott Shewey:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waving said objection, See answer to 1-9.b above. Rate recovery above cost, or margins, collected by cooperatives are used to supplement short-term capital needs and are returned to members over time.

1-10) Will NZ1 pay for its share of East River's transmission buildout in Exhibit 5 that isn't covered under the CIAC agreement? More specifically, please provide NZ1's expected share of those costs and explain how that share will be recovered from NZ1.

Answered by Scott Shewey:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waving said objection, yes, NZ1 will pay for its share of the transmission buildout which is included in the rate recovery of system-wide costs. The cost is recovered on both the demand and energy charges.

1-11) Referring to the "East River Kingsbury County Substation – Online" diagram in Exhibit 5 of NZ1's Petition, please identify the meter that NZ1's demand and energy will be metered at for billing.

Answered by Mark Hoffman:

Meters 3, 4 and 5 on the diagram, subject to final design of the substation and facility.

1-12) Has East River made any investment to date in anticipation of KEC serving the NZ1 load? If yes, please identify those investments and the costs East River has incurred.

Answered by Mark Hoffman:

Yes, we have costs assigned to the project including labor, design, land acquisition, and have ordered long lead time equipment.

Daniel J. Brown, Attorney for East River, hereby objects to certain requests, as shown above.

Dated this 14th , day October, 2024.

East River Electric Power Cooperative, Inc.

By: _/s/Daniel J. Brown_________________

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EXHIBIT 2

SPP 2O24 INTEGRATED TRANSMISSION PLANNING ASSESSMENT REPORT PUBLISHED 10/07/2024

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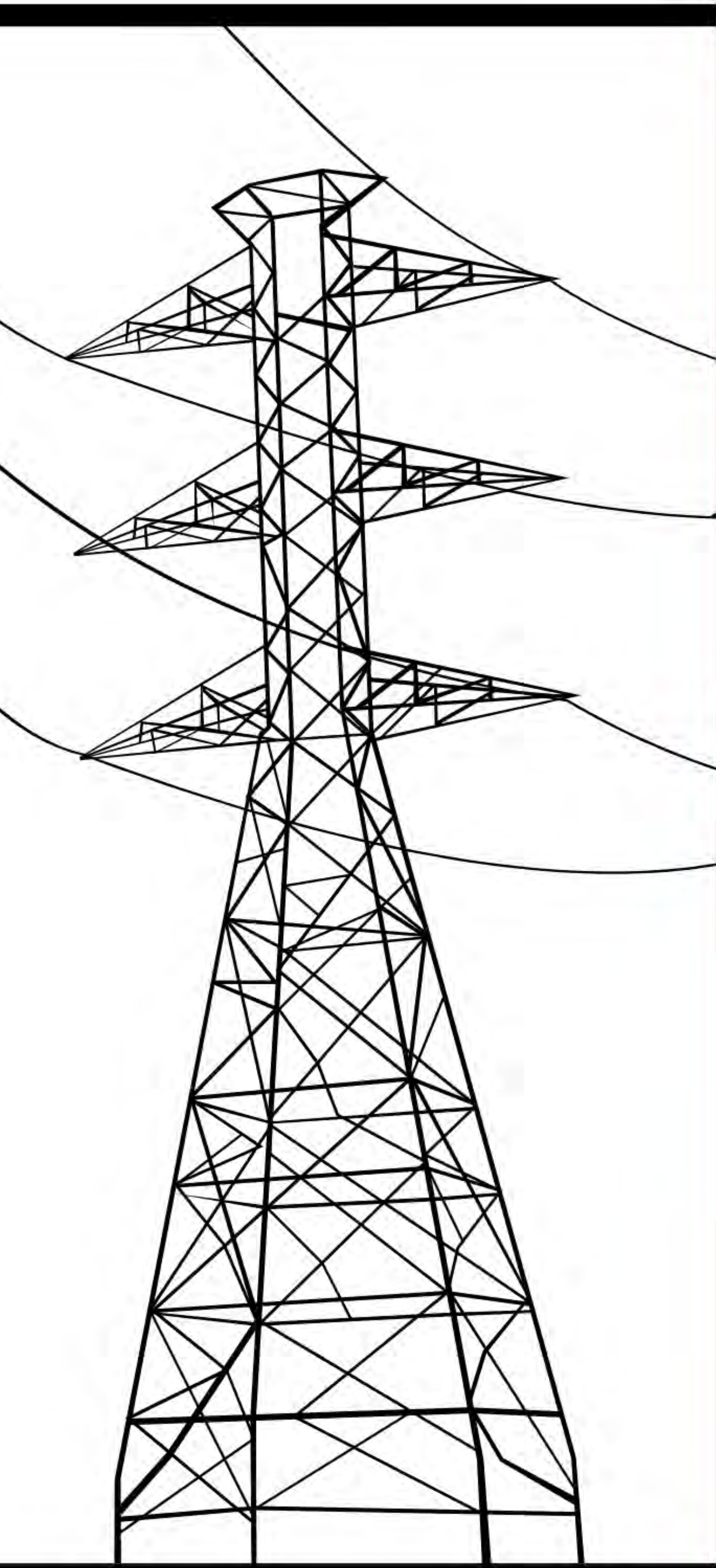

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2024 INTEGRATED TRANSMISSION PLANNING ASSESSMENT REPORT

SPP Engineering
Version 0.6
Published 10/07/2024

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
0.1	SPP Staff	Report draft through solution evaluation	Posting partial draft for TWG and ESWG review 8/21/2024
0.2	SPP Staff	Full draft	Posting draft for TWG and ESWG review 9/18/2024
0.3	SPP Staff	Full draft with redline proposed changes	Posting draft for TWG and ESWG as presented on 9/25/2024
0.4	SPP Staff	Full draft with additional redline changes as discussed in the Joint ESWG-TWG meeting on 9/25/2024	Posting for TWG and ESWG review on 9/26/2024
0.5	SPP Staff	Project area clarifications, updated staging dates, and updated project costs	Posting for TWG and ESWG approval on 10/02/2024
0.6	SPP Staff	Updates as made during ESWG-TWG Joint meeting on 10/03/2024, and added additional Winter Weather Staging section	TWG and ESWG approved on 10/03/2024

ACKNOWLEDGEMENTS

SPP would like to recognize the significant contributions to the 2024 ITP study. The Transmission Working Group (TWG), Economic Studies Working Group (ESWG), Winter Weather Planning Strike Team, and SPP Engineering staff have been instrumental in shaping this effort. SPP staff collaborated closely with these groups to develop futures, build models, review critical data points, and ensure that milestones were completed in compliance with the SPP Open Access Transmission Tariff (SPP OATT) and the 2024 ITP Scope.

In addition to the TWG and ESWG, the SPP Markets and Operations Policy Committee (MOPC) and Strategic Planning Committee (SPC) played key roles in reviewing study assumptions and recommending the evaluation of extreme winter scenarios for inclusion in the 2024 ITP.

SPP staff worked diligently to execute key milestones, including model building, needs assessment, portfolio development, and report preparation. Two core departments—Engineering Services and System Planning—were instrumental in the successful completion of the study.

SPP staff would also like to acknowledge the contributions of the stakeholders who provided valuable input during the additional winter weather model and process reviews, helping to ensure the thoroughness of the analysis.

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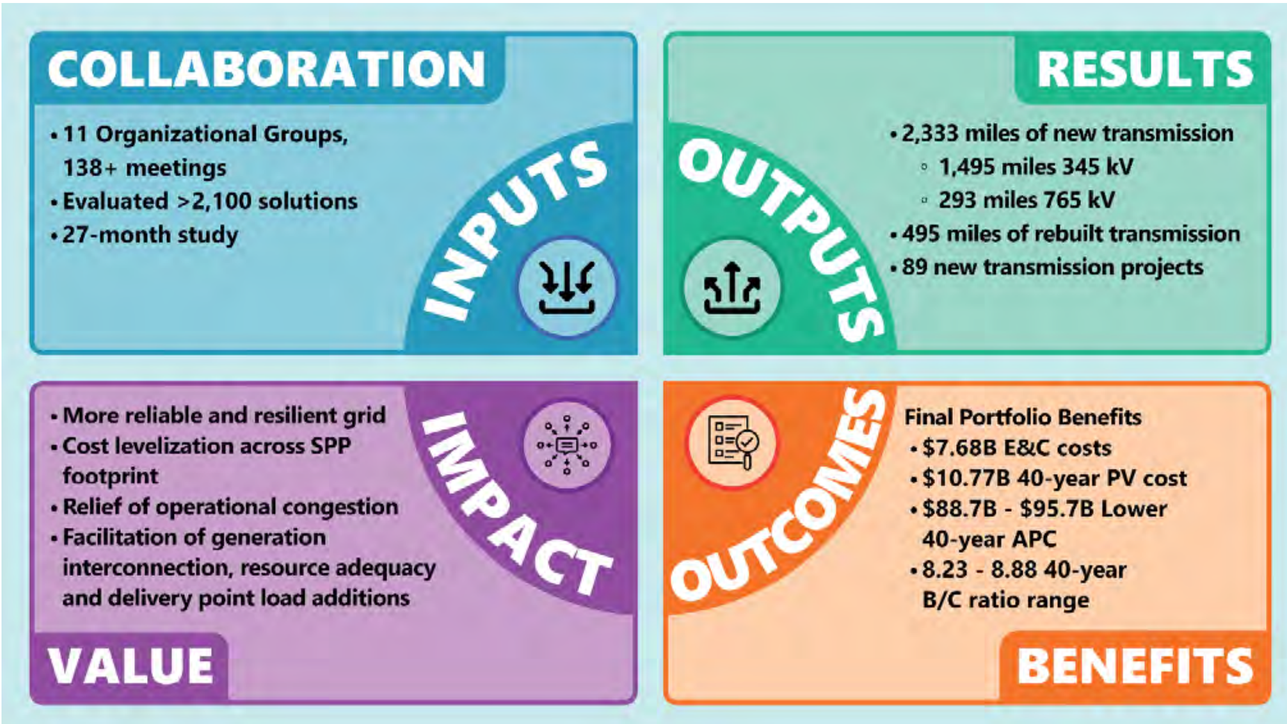
EXECUTIVE SUMMARY



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INTRODUCTION

The 2024 Integrated Transmission Planning (ITP) Assessment ushers SPP into a new era of investment in the grid of the future. This portfolio signifies the footprint's prioritization of reliability and driving increasing value beyond reliability by recommending projects that also address resiliency and economic concerns. To help meet the energy needs of our members today and in the future, SPP developed a portfolio of nearly 100 transmission projects to address reliability, economic, policy and operational needs. Additionally, SPP focused on improving system resiliency by identifying and recommending NTCs for projects that can help support the system during extreme weather events. The 2024 ITP portfolio recognizes that more transmission must be built to meet the supply and demand challenge the SPP footprint is facing.

The 2024 ITP portfolio comes with an investment of $7.68 billion and boasts a benefit-to-cost(B/C) ratio of 8.23-8.88[1]. The recommended investment estimated savings to ratepayers and the B/C ratios are the highest values in the history of the ITP. Arriving at a portfolio recommendation involved extensive stakeholder collaboration and support. The proactive transmission planning of the ITP is expected to maximize the benefit to SPP's end-use customers and levelize Locational Marginal Prices (LMPs) across the footprint. The portfolio of projects will reliably support the delivery of power to SPP's growing load.

[1] The calculations of the benefit ratios do not include the projects identified in the final reliability assessment.

The estimated net impact to ratepayers is a savings of $10.55 to $11.47 on the average retail residential monthly bill.

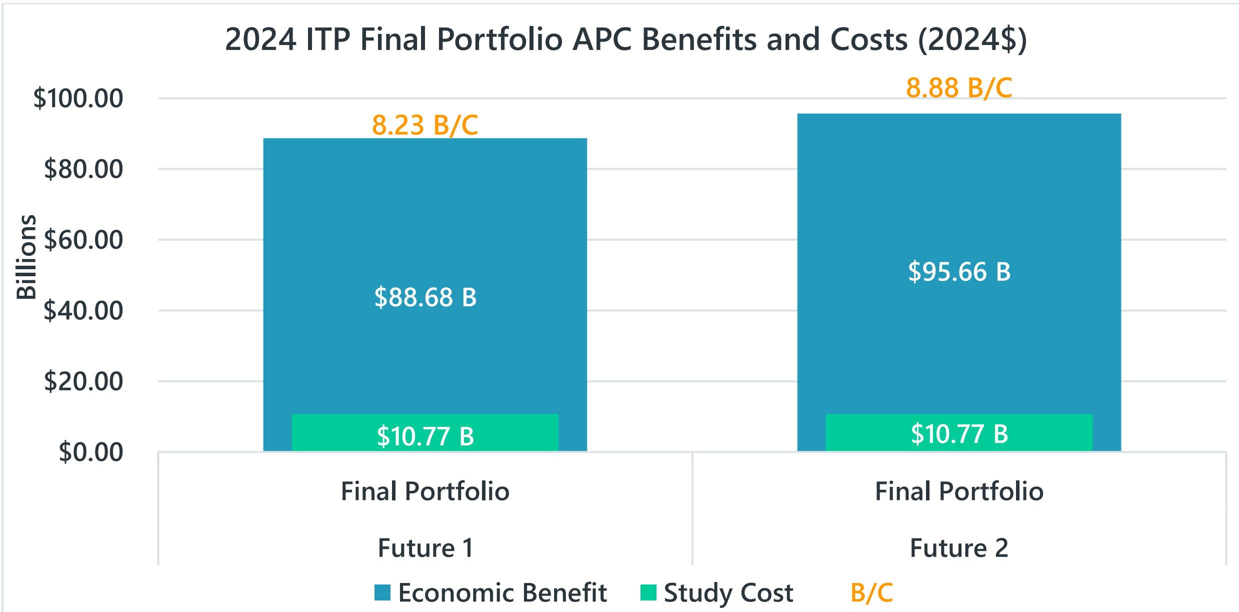

Figure 0.1: 2024 ITP Final Portfolio APC Benefits and Costs (2024$)

SPP expects the recommended consolidated portfolio to be cost beneficial within the first year of being placed in-service and to pay back the total investment within the first three years.[2]

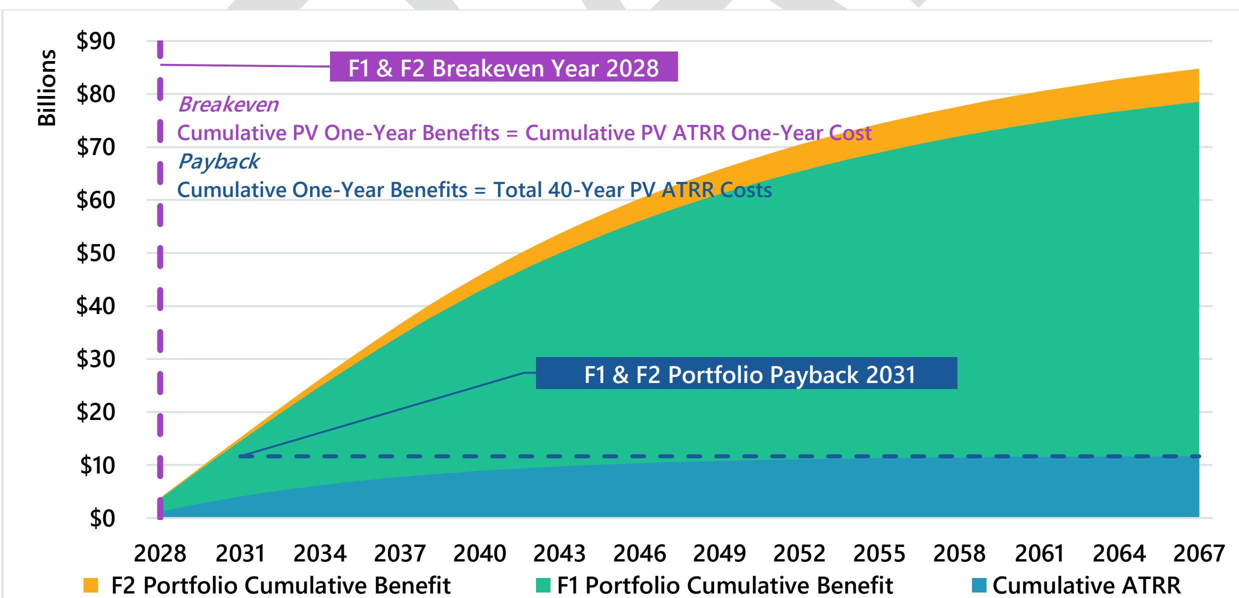

Figure 0.2: Final Portfolio Break-even and Payback Dates

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[2] This breakeven and payback period calculation is a conservative estimate that assumes the entire portfolio of solutions is placed in service in Year five and is not reflective of NTC issuance and projected in-service dates for each project.

SPP recognized that the SPP footprint is facing a Generational Challenge[3] as the need arises to balance new sources of demand, like data centers, crypto mining, mining, and oil and gas production, with the retirement of conventional resources that use coal and natural as fuel sources. The 2024 ITP considered a uniquely sharp increase in load at multiple sites across the SPP footprint compared to previous ITP assessments.

To ensure timely, informed, and adequate transmission investment to support continued load growth, SPP identified areas in the SPP footprint which are forecasted to experience rapid load growth within the next 10 years. SPP used this information to inform decisions made while crafting the 2024 ITP portfolio.

SPP's Aspire 2026 Strategic plan guided SPP while conducting the 2024 ITP.[4] SPP developed this five-year strategic plan in 2020 to shape what SPP would achieve in the subsequent five years. The outcomes of the 2024 ITP align with the following defined 2026 aspirations, value propositions and strategic opportunities.

- **Deliver greater, more equitable value to our members** – The economic projects within the 2024 ITP portfolio continue the levelization of energy costs east toward SPP members currently experiencing higher than average prices.
- **Achieve seamless boundaries** – The 2024 ITP portfolio recommends transmission that improves intra-regional transfer capability and provides greater access to renewable energy for a broader set of SPP members and SPP's neighbors.
- **Innovative Transmission Planning** – SPP staff and stakeholders took advantage of a strategic opportunity in the 2024 ITP by creating multiple extreme winter weather models sets with recommended transmission investment to improve system resiliency.
- **Attain high-quality decisions though an efficient collaborative stakeholder process** – SPP staff and stakeholders championed the 2024 ITP at over 138 stakeholder working group meetings over 27 months. Stakeholders provided valuable feedback during these meetings. SPP staff held numerous conversations with individual local Transmission Owners (TO) to discuss project feasibility and identify the best solutions. Additionally, SPP staff provided quarterly updates to the Markets and Operations Policy Committee (MOPC) of pertinent technical details and challenges as the ITP Assessment continued to evolve. These key pieces of the overall collaboration between SPP staff and stakeholders contributed to the strong support for the 2024 ITP portfolio voiced by stakeholders at working groups, the 2024 Engineering Planning Summit, and the MOPC meetings leading up to the final proposal.
- **Drive value beyond reliability**- While developing the 2024 ITP portfolio, SPP staff looked for projects that could provide benefits beyond reliability. SPP staff identified 12 projects that provide reliability and economic benefits. The B/C ratios of the recommended economic groupings of projects were the highest ever recorded in the ITP at almost 23-to-1 and 26-to-1 for Future 1 and Future 2, respectively.

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[3] https://spp.org/media/2162/our-generational-challenge-infographic.pdf; https://spp.org/media/2163/our-generational-challenge-paper.pdf

[4] https://www.spp.org/spp-documents-filings/?id=467485

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- **Achieve collaboratively and engage passionately**- SPP staff created a Winter Weather Strike Team (WWST) made up of interested stakeholders to support model development and analysis methodologies. The WWST met weekly for most of the 2023 calendar year to brainstorm the optimal approach to evaluate extreme winter weather as a meaningful input into the 2024 ITP. The outcome of this collaboration resulted in clear direction and path forward for the Transmission Working Group (TWG) and Economic Studies Working Group (ESWG). In April 2023, after significant staff and stakeholder collaboration, the MOPC approved the revised 2024 ITP scope which directed analysis of two target areas that were impacted by extreme winter weather.

To develop a robust portfolio, SPP evaluated more than 2,100 solutions developed by SPP stakeholders and SPP staff. The analysis resulted in the recommendation to approve 88 new transmission projects, including:

- 1,788 miles of new extra-high-voltage (EHV) transmission
- 148 miles of rebuilt EHV transmission infrastructure
- 545 miles of new high-voltage transmission
- 347 miles of rebuilt high-voltage transmission infrastructure

These projects uphold SPP's requirement to support firm deliverability of capacity for reliability, and a commitment to resolving transmission congestion across the SPP footprint.

The 2024 ITP portfolio is comprised of reliability, winter weather, economic, short circuit and operational projects that will mitigate 1,062 system issues. Reliability projects allow the region to meet compliance requirements and keep the lights on by providing loading relief, voltage support, and system protection. Winter weather projects address voltage and thermal overload violations that SPP observed during winter storm Elliott and a generically modeled winter storm based on aggregation of common stressors from multiple previous storms. Economic projects allow the region to lower energy costs through mitigation of transmission congestion.

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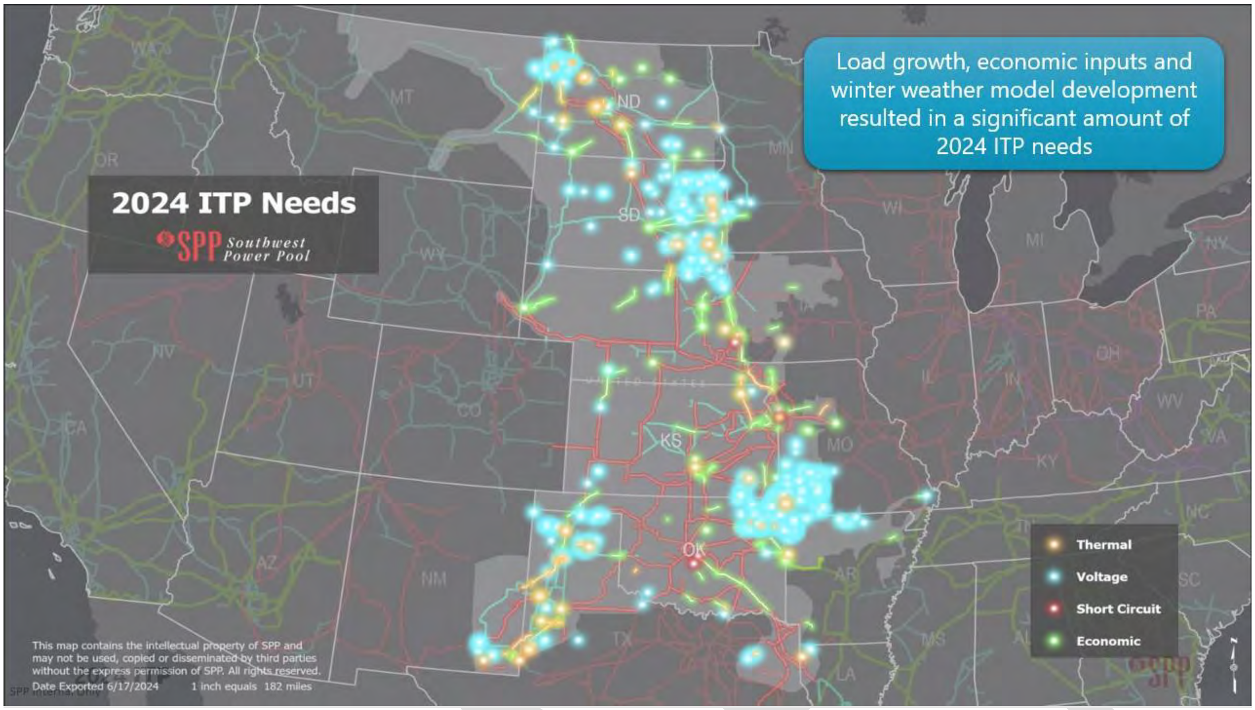

Figure 0.3: Map of 2024 ITP Needs as of DPP Window Opening[5]

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DIVERSE PORTFOLIO BENEFITS

2024 ITP PORTFOLIO BENEFITS

The 2024 ITP portfolio projects will benefit the SPP region in a myriad of ways. Based on the implementation of the portfolio, SPP observed benefits to reliability, resilience, and decreased cost for end-use customers. SPP addressed uniquely sharp load increases in New Mexico by recommending its first 765 kV line from Phantom to Crossroads to Potter as detailed in section 6.1.12.2. This project spans from the panhandle of Texas to southeastern New Mexico, delivering much needed energy to a remote area of the region. To address the rapid load growth in North Dakota and South Dakota, SPP staff recommended a network of new and upgraded lines across this area. These projects are detailed in section 6.1.13.1. These recommendations for EHV solutions into this area of concentrated load growth contribute to SPP's strategic opportunity to develop a robust "grid of the future."

SPP crafted the 2024 ITP portfolio to capitalize on the economic benefits of improved system flows caused by projects identified in the reliability portfolio. SPP is optimizing seams by extending EHV transmission into southern central Missouri where the SPP region shares customers with neighboring utilities. This transmission will enable lower cost energy from the central part of SPP to reach an area where real-time pricing data shows consistently higher prices compared to the rest of SPP. Additionally,

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[5] Prior to the opening of the Detailed Project Proposal (DPP) window (Feb. 2024), SPP staff collaborated with the local Transmission Owners (TOs) to invalidated needs. Additional invalidation occurred following the opening of the DPP window.

SPP expects the 2024 ITP portfolio projects to increase energy equity by expanding SPP's EHV footprint to areas designated by the U.S. Department of Energy (DOE) as National Interest Electric Transmission Corridors (NIETC).

SPP's analysis of resiliency against winter storms identified projects that improve system voltages throughout the approved target areas. These projects include transmission necessary for generation from outside of this area to reliably reach the loads. Increasing imports is especially important when the limited natural gas supply restricts local generation or transmission congestion prevents local generation from coming online. SPP also identified projects that increased the transmission system's ability to transfer power from north to south within the SPP footprint by approximately 1.5 GW. This further increases resiliency against extreme winter storms by enabling SPP's northern generation facilities which are hardened to withstand extreme temperatures to deliver power to the southern portion of SPP's footprint.

WINTER STORM ANALYSIS

SPP recognizes that all generation struggles to perform during extreme weather when demand is highest and human health and safety are at greatest risk. SPP also acknowledges that these risks will increase exponentially if we don't take the steps necessary to address our Generational Challenge. In 2021 and 2022, the central United States experienced multiple historic winter storms producing record-low temperatures and record-high electricity use. The conditions severely tested the flexibility of the overall bulk electric system. To increase the resiliency of the SPP transmission system against such storms and drive value beyond reliability, SPP and its member organizations collaborated throughout the 2024 ITP to employ innovative transmission planning strategies by developing two winter weather cases. One case was based on winter storm Elliott (December 2022) and one captured footprint-wide winter storm effects. SPP recommends Notification to Construct (NTC) issuance for most of the projects in Table 0.1 as shown in Figure 1.3 to address the violations observed in these winter weather cases. SPP staff found that when the full portfolio was applied to the year two and year five Elliott-based Winter Weather models, no load shed would be expected to occur.

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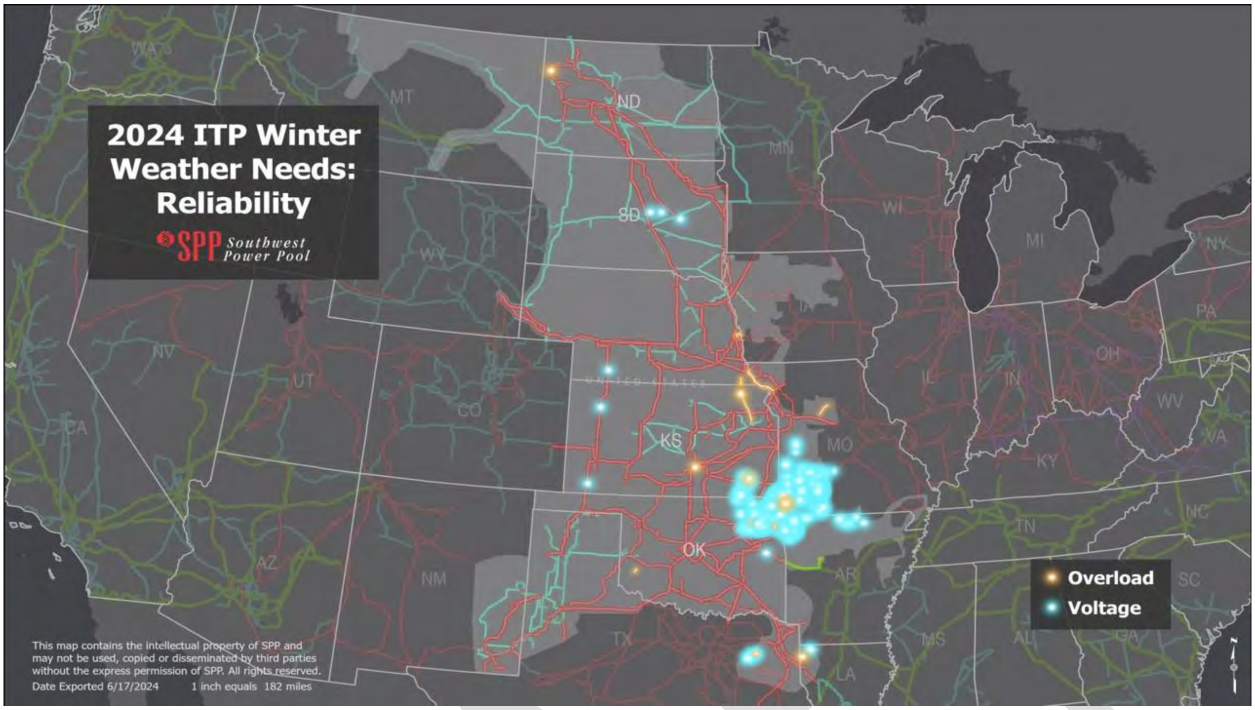

Figure 0.4: Winter Weather Needs

General Description	State	Miles	Cost
Aurora - Reeds Spring 161 kV Rebuild	MO	23.7	$37,904,869
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	MO	11.5	$22,835,547
Branson North- Ozark Dam 161 kV Ckt 1 Rebuild	MO	7.1	$12,375,255
Buffalo Flats - Delaware 345 kV New Line	KS/OK	154.6	$484,090,326
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps	MO	2	$70,122,330
Delaware - Monett 345 kV Ckt 1 New Line	OK/MO	114.5	$342,608,905
Elm Creek - Tobias 345 kV New Line	KS/NE	85.2	$148,419,672
Holcomb - Sidney 345 kV Ckt 1 New Line	KS/NE	300	$887,460,816
Monett - North Branson 345 kV Ckt 1 New Line	MO	47.2	$165,800,962
Ozark Dam - Forsyth North - Ozark South 161 kV Voltage Conversion	MO	28.2	$38,032,729
Reed Springs - North Branson - Northwest Branson - Branson North 161 kV Rebuild	MO	9.9	$17,108,010
	Total:	**783.9**	**$2,226,759,421**

Table 0.1: Winter Weather Projects

SPP is collaborating with stakeholders to improve the transmission system to address concerns of resource adequacy and deliverability, which were highlighted by recent winter events. As the Balancing Authority (BA), SPP works with the Load Responsible Entities (LRE) to ensure they supply adequate resources to serve their load. SPP embraced the opportunity to identify projects that will free generation blocked by congested lines. The ITP portfolio includes projects that would allow resources to flow more effectively to serve their loads.

BENEFITS TO OTHER SPP PLANNING PROCESSES

The 2024 ITP portfolio projects will provide benefits to SPP stakeholders across multiple services and markets. Unlike other SPP assessments, the ITP provides a holistic analysis of system needs, and thus selects projects to address needs in a manner that is optimal for the SPP footprint. The 2024 ITP portfolio provides relief on constraints binding SPP's congestion hedging markets, and, in turn, increases SPP's ability to award ARRs for members.

DELIVERY POINT ASSESSMENT (DPA)

Under Attachment AQ of the SPP Open Access Transmission Tariff (OATT), Transmission Customers (TC) can request that SPP and TOs assess additions, modifications, or abandonments of local physical delivery points. This process is frequently used to identify Network Upgrades required to accommodate delivery point changes, usually in the form of new load. In contrast, the ITP looks collectively at approved delivery point changes, allowing SPP to identify more optimal solutions. Based on Attachment AQ Section 3.4 of the Tariff, SPP staff includes these load changes in the ITP Assessment. Both studies issue NTCs to projects that address regional needs.

The 2024 ITP portfolio overlapped with analysis performed in the DPA process evaluating new loads. This overlap allows the ITP Assessment to use a more holistic approach by considering violations flagged by both processes. The DPA process realizes the following benefits:

- Issuance of fewer projects, as the ITP Assessment has already resolved violations that the additional load would have created.
- More robust base models and transmission system, as the ITP Assessment selected more holistic projects than the DPA process would have selected
- More cost-beneficial project selection due to the inclusion of economic analysis in the ITP Assessment
- Reduced time spent on analysis, as holistic solutions have already resolved violations

GENERATOR INTERCONNECTION (GI)

The comprehensive analysis performed for the 2024 ITP portfolio benefits the GI process[6] by increasing transmission system capacity. This increased capacity provides an acceleration of the interconnection process and will help facilitate the connection of over 7.8 GW of conventional and dispatchable generation currently in the GI queue.

One of SPP's goals is to support the attainment of resource adequacy. This is done in part by ensuring there is enough capacity available to meet the needs of all end-use customers in SPP. This goal also is supported by the recommendation of transmission to allow power from SPP resources to efficiently reach SPP loads. Constraints restricting this flow of power will be assessed in the GI NRIS+ analysis. Relieving constraints identified as congested in SPP NRIS+ analysis would increase deliverability, in turn increasing resource adequacy.

[6] SPP OATT Attachment V

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NETWORK RESOURCE INTERCONNECTION SERVICE (NRIS+)

SPP conducted a study as part of its initiative to make pre-qualified deliverability part of NRIS service ("NRIS+")[7]. The NRIS+ transition study was designed to determine how much power can be delivered from existing resources within defined zones or "deliverability areas" to transition them to the new NRIS+ service. Below are upgrades for constraint that were identified in the NRIS+ transition study as preventing full deliverability of existing resources that may be at least partially relieved by projects included in the 2024 ITP.

2024 ITP Project Expected to Relieve Constraint	NRIS+ Proposed Mitigation	Avoided Cost of CRIS Project
Potter – Beckham County 345 kV New Line	Sweetwater - Chisholm 230 kV Rebuild & New Ckt 2 New Line	$22,759,324
	Chisholm - Elk City 230 kV Rebuild & New Ckt 2 New Line	$38,272,406
	Add a third 230/115/13.8 transformer at Hitchland	$6,621,188
	Add a third 345/230/13.8 transformer at Hitchland	$8,302,968
	Potter County - Hitchland 345 kV Rebuild	$117,419,954
	Bushland - Potter County 230 kV Rebuild	$16,742,496
	Harrington - Potter County 230 kV Rebuild	$9,895,301
	Potter County - McDowell Creek 230 kV Rebuild	$17,307,941
	Wheeler - State Line Demarcation 230 kV Rebuild	$12,298,445
	Potter County 345/230 kV Ckt 2 Transformer	$8,302,968
	Total Avoided Cost of CRIS Project:	**$257,922,992**
Sidney – Holcomb 345 kV New Line	Gentleman - Ogalala 230 kV Line	$26,584,786
	Ogalala - Sidney 230 kV Line	$60,652,893
	Total Avoided Cost of CRIS Project:	**$87,237,679**

Table 0.2 NRIS+ Mitigation Projects Replaced by 2024 ITP Portfolio

RESOURCE ADEQUACY

Projects recommended in the 2024 ITP to address winter weather needs will improve system resiliency, which increases resource adequacy during extreme conditions. By improving SPP's transmission system, the transfer capability among Loss of Load Expectation (LOLE) zones is increased. This enhances the potential delivery of firm service.

COLLABORATION WITH SPP'S NEIGHBORS

SPP recognizes the necessity to work together within our region while working across SPP seams to exchange energy and collaborate on interregional projects that provide mutual benefit.

[7] The NRIS+ transition study was originally titled the Capacity Resource Interconnection Service (CRIS) transition study.

MISO-SPP JOINT TARGETED INTERCONNECTION QUEUE (JTIQ) STUDY

From 2020 to 2022, SPP and Midcontinent Independent System Operator (MISO) performed the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study. Through collaboration between the Regional Transmission Organizations (RTOs), the study identified transmission projects required to address the significant transmission limitations restricting the opportunity to interconnect new generating resources near the SPP-MISO seam. The study was completed in the spring of 2022 and is pending a decision on the filed revision request from the Federal Energy Regulatory Commission (FERC). As a result, the MISO and SPP Boards of Directors had not yet approved the projects for construction, which is prior to the completion of the 2024 ITP. In the 2024 ITP, SPP staff evaluated the impact of the JTIQ portfolio on the 2024 ITP project to validate the need for the recommended ITP projects and ensure that one group of projects does not harm the other.

SPP-AECI JOINT & COORDINATED SYSTEM PLANNING (JCSP)

Every two years, SPP and Associated Electric Cooperative Incorporated (AECI) collaborate to perform a Joint & Coordinated System Planning (JCSP) assessment. The 2024 SPP-AECI JCSP assessment, performed in parallel with the 2024 ITP, used the 2024 ITP models and examined opportunities for collaboration to address reliability and economic violations. Because the ITP schedule preceded the JCSP schedule, the 2024 ITP informs the 2024 SPP-AECI JCSP assessment, highlighting opportunities for potential cost sharing between SPP and AECI for transmission projects that provide mutual benefit. More information about any transmission projects that will be considered for potential cost sharing between SPP and AECI will be available in the AECI-SPP JCSP report. The AECI-SPP JCSP report is scheduled to be published by AECI and SPP in October 2024. It should be noted here that some of the transmission projects in the 2024 ITP portfolio addressing winter weather needs in the target area also address needs that have been evaluated in the JCSP. There are promising potential opportunities for some level of cost sharing between AECI and SPP for the following projects:

Description	Miles	Voltage Level	NTC	Cost
Aurora - Reeds Spring 161 kV Rebuild	23.7	161	NTC-C	$37,904,869
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	11.5	161	NTC-C	$22,835,547
Branson North - Branson Northwest -North Branson - Reed Springs 161 kV Rebuild	4.5	161	NTC	$16,704,792
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps	2	161	NTC-C /TBD[8]	$70,122,330
Delaware - Monett 345 kV Ckt 1 New Line	114.5	345	NTC-C	$342,608,905
Lamar 161/69 kV Ckt 2 Transformer		161		$7,641,150
Monett - North Branson 345 kV Ckt 1 New Line	47.2	345	NTC-C	$165,800,962
N Reeds Spring - S Reeds Spring 161 kV Rebuild	1.5	161	NTC	$3,266,430
Branson North - Ozark Dam 161 kV Ckt 1 Rebuild	7.1	161	NTC	$12,375,255
Ozark Dam - Forsyth North - Ozark South 161 kV Voltage Conversion	28.2	161	NTC-C	$38,032,729

Table 0.3: Projects with 2024 JCSP Cost-Sharing Potential

[8] SPP facilities included in this upgrade will receive an NTC-C

WESTERN AREA POWER ADMINISTRATION-ROCKY MOUNTAIN REGION (WAPA-RMR)

Throughout the development of the economic portfolio, SPP identified multiple opportunities to collaborate with WAPA-RMR to reduce economic congestion on the constraint from Gerring Tap to Scotts Bluff and Alliance to Snake Creek. Once SPP's Board of Directors (BOD) approves the portfolio, SPP will begin conversations with WAPA-RMR to coordinate the construction and facility usage of these projects that received an NTC.

FEDERAL PROGRAMS

NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDORS (NIETC)

The NIETC initiative seeks to combat harm caused by a lack of transmission infrastructure, such as high electricity prices, more frequent power outages, and longer outages after extreme weather. To this end, the Federal Power Act authorized the Secretary of Energy to "designate any geographic area as a National Interest Electric Transmission Corridor (NIETC) if the Secretary finds that consumers are harmed by a lack of transmission in the area and that the development of new transmission would advance important national interests in that area, such as increased reliability and reduced consumer costs."[9] Through this process, the Secretary of Energy identified NIETCs across SPP's footprint. If a project falls within a NIETC designation, increased federal funding and permitting tools may be available to help accelerate the construction of these projects.

Figure 0.5: NIETC Corridors

[9] Quote from: https://www.energy.gov/gdo/national-interest-electric-transmission-corridor-designation-process

The project Belfield to Maurine to New Underwood to Laramie River 345 kV New Line recommended for NTC in the 2024 ITP is located within the Northern Plains NIETC. This project spans from Colorado to Nebraska to South Dakota to North Dakota.

Figure 0.6: NIETC Great Plains Corridor

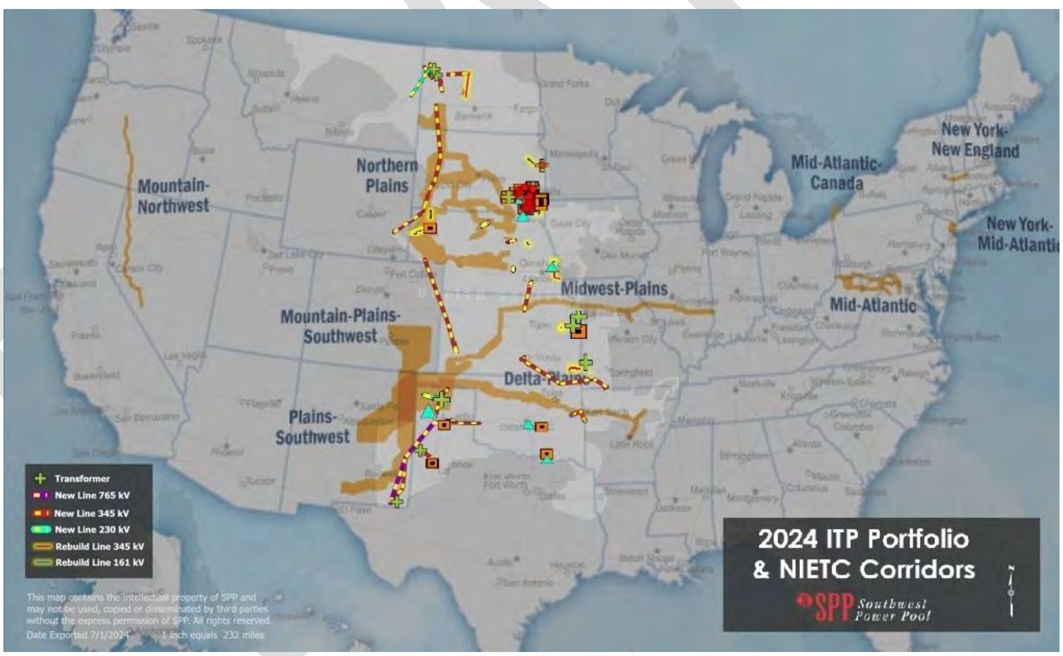

Figure 0.7: 2024 ITP Portfolio and NIETC Corridors

DOE NATIONAL TRANSMISSION PLANNING STUDY

The DOE's Office of Electricity has created the Building a Better Grid initiative to "catalyze the nationwide development of new and upgraded high-capacity transmission lines".[10] Following the

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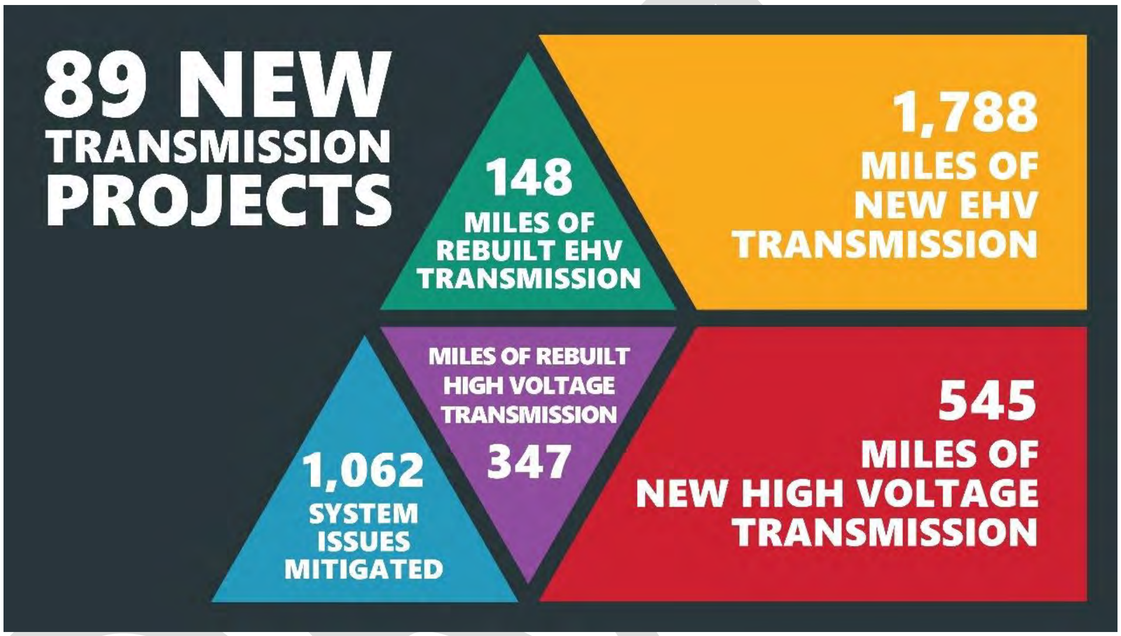
[10] https://www.energy.gov/gdo/national-transmission-planning-study

approval of the 2024 ITP, SPP will work with stakeholder groups to determine which projects may fit the scope of future DOE funding opportunities.

STUDY FINALIZATION

The 2024 ITP portfolio will contribute to SPP's mission of working together to responsibly an economically keep the lights on today and in the future while leading our industry to a bright future and delivering the best energy value. SPP staff's complete 2024 ITP recommended portfolio, including SPP's recommendations for issuances of a Notification to Construct (with Conditions) (NTC or NTC-C), is in Table 1.1.



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1 INTRODUCTION

1.1 THE ITP ASSESSMENT

The SPP ITP process promotes transmission investment to meet near- and long-term reliability, economic, public policy and operational transmission needs. The ITP process coordinates solutions with ongoing compliance, local planning, interregional planning and tariff service processes. The goal is to develop a 10-year regional transmission plan that provides reliable and economic energy delivery and achieves public policy objectives, while maximizing benefits to the end-use customers. The 2024 ITP is guided by requirements defined in Attachment O of the SPP OATT,[11] the ITP Manual,[12] and the 2024 ITP scope.[13]

The ITP process is open and transparent, allowing for stakeholder input throughout the assessment. SPP staff coordinated the study results with other entities, including those embedded within the SPP footprint and neighboring first-tier entities.

The objectives of the ITP are to:

- Resolve reliability criteria violations
- Improve access to markets
- Improve interconnections with SPP neighbors
- Meet expected load-growth demands
- Facilitate or respond to expected facility retirements
- Synergize with the Generator Interconnection (GI), Aggregate Transmission Service Studies (ATSS), and Delivery Point Assessment (DPA) processes
- Address persistent operational issues
- Facilitate continuity in the overall transmission expansion plan
- Facilitate a cost effective, responsive and flexible transmission network

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[11] https://spp.etariff.biz:8443/viewer/viewer.aspx

[12] ITP Manual version 2.16; the ITP assessment follows the current ITP Manual and versions may differ throughout the study process. The version that was current at the time of the study was used.

[13] 2024 ITP Scope version 1.4; presents the scope and schedule of work for the 2024 ITP.

1.2 REPORT STRUCTURE

This report describes the 2024 ITP Assessment of the SPP transmission system over a 10-year horizon, focusing on 2025, 2028 and 2033. SPP evaluated these years under a baseline reliability scenario and two future market scenarios (futures). New to the 2024 ITP is the addition of extreme winter models. The Study Drivers section (section 2) describes the major study drivers in detail for the 2024 ITP. The Model Development and Benchmarking sections (section 3) summarize modeling inputs and address the concepts behind this study's approach, key procedural steps in analysis development and overarching study assumptions. The Needs Assessment through Project Recommendations sections (sections 4-6) address specific results, describe projects that merit consideration, and contain portfolio recommendations, benefits and costs. The Informational Portfolio Analysis section (section 7) summarizes additional benefits and sensitivities related to the portfolio.

Any reference to the SPP footprint refers to the Balancing Authority Area, as defined in the Tariff, whose transmission facilities are under the functional control of the SPP regional transmission organization (RTO), unless otherwise noted. The study was guided by the 2024 ITP Scope and SPP ITP Manual. All reports and documents referenced in this report are available on the SPP website.

Both SPP's staff and stakeholders frequently exchange proprietary information during any study, and such information is used extensively for ITP assessments. This report does not contain confidential marketing data, pricing information, marketing strategies, or other data considered not acceptable for release into the public domain. This report does disclose planning and operational matters, including the outcome of certain contingencies, operating transfer capabilities and plans for new facilities that are considered non-sensitive data.

1.3 STAKEHOLDER COLLABORATION

Stakeholders developed the 2024 ITP assumptions and procedures in meetings throughout 2022, 2023, and 2024. SPP staff, members, liaison members, industry specialists and consultants discussed the assumptions and facilitated a thorough evaluation.

The following SPP organizational groups were involved:

- Transmission Working Group (TWG)
- Economic Studies Working Group (ESWG)
- Model Development Advisory Group (MDAG)
- Cost Allocation Working Group (CAWG)
- Project Cost Working Group (PCWG)
- Markets and Operations Policy Committee (MOPC)
- Strategic Planning Committee (SPC)
- Regional State Committee (RSC)
- Board of Directors (Board)
- Interregional Planning Stakeholder Advisory Committee (IPSAC)
- Operating Reliability Working Group (ORWG)

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SPP staff served as facilitators for these groups and worked closely with stakeholders to ensure all views were heard and considered, consistent with the SPP value proposition.

These working groups tendered policy-level considerations to the appropriate organizational groups, including the MOPC and SPC. Stakeholder feedback was instrumental in the refinement of the 2024 ITP.

1.4 FINAL PORTFOLIO AND NTC RECOMMENDATIONS

Table 1.1 identifies the 2024 ITP Assessment projects that SPP staff recommends for approval to the SPP Board of Directors. Included in the table are simplified project descriptions, other key data, and a column identifying whether the project was approved by the SPP Board with the intent to issue a Notification to Construct (NTC) or Notification to Construct with Conditions (NTC-C). NTC/NTC-C projects recommended by the board are to be constructed and placed in service in accordance with the recommended need dates that are identified later in this report.

Description	Area	Type	Project Cost (2024$)	Miles	NTC/ NTC-C[14]
15th Ave - Watertown 115 kV Rebuild	MRES/WAPA	R	$2,158,980	1.4	NTC
Ainsworth - Bassett 115 kV Ckt 1 New Line	NPPD	R	$25,100,000	19.6	NTC-C
Alliance - Snake Creek 115 kV Rebuild	WAPA-RMR	E	$12,055,000	14.9	TBD
Alliance - Snake Creek 115 kV Terminal Upgrade	WAPA-RMR	O	$770,666		TBD
Antelope - Holt County 345 kV Ckt 1 New Line	NPPD	E	$67,100,000	24	NTC-C
Aurora - Central City 115 kV Ckt 1 New Line	NPPD	R	$13,700,000	13.2	NTC
Aurora - Reeds Spring 161 kV Rebuild	EMDE	WW	$37,904,869	23.7	NTC-C
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	EMDE	O/WW	$22,835,547	11.5	NTC-C
Beckham County - Potter 345 kV New Line	OGE/SPS	E	$428,620,878	149.6	NTC-C
Belfield - Maurine - New Underwood - Laramie River 345 kV New Line	BEPC/WAPA	E	$1,114,609,566	438.6	NTC-C
Bismarck - East Bismarck 115 kV Rebuild	WAPA/CPEC	E/R	$1,209,664	0.4	NTC
Blackberry - Neosho 345 kV Rebuild	KAMO/WERE	E	$46,612,099	31.5	
Branson North - Branson Northwest -North Branson - Reed Springs 161 kV Rebuild	EMDE	WW	$16,704,792	9.9	NTC
Branson North - Ozark Dam 161 kV Ckt 1 Rebuild	EMDE	WW	$12,375,255	7.1	NTC
Brown - Colbert 138 kV Terminal Equipment	OGE/SWPA	E/R	$851,006		NTC
Buffalo Flats - Delaware 345 kV New Line	AEP	WW	$484,090,326	154.6	NTC-C
Bull Shoals - Midway Jordan 161 kV Rebuild	SWPA/EEA	E	$12,785,321	9.3	TBD
Butler - Midian 138 kV Rebuild	WERE	E	$10,906,736	3	NTC
Butler South - Tallgrass 138 kV Rebuild	WERE	E	$19,571,986	9.9	NTC
Catoosa 161/138 kV Transformer	GRDA/AEP	E	$7,641,150		NTC
CDC East - Tulsa North 138 kV Rebuild	AEP	E	$5,804,960	4.6	NTC

[14] A blank in this column indicates that no NTC or NTC-C will be issued. TBD in this column indicates that there are upgrades within the project that are not under the SPP tariff and no NTC or NTC-C can be issued, however SPP will coordinate with the external parties to get the upgrade(s) constructed.

Description	Area	Type	Project Cost (2024$)	Miles	NTC/ NTC-C[14]
Chadron - Dunlap 115 kV Ckt 1 Rebuild	NPPD/ WAPA-RMR	E	$19,314,577	18.7	
Channing 230 kV Capacitor	SPS	R	$4,467,052		NTC
Chisholm - Maize - Evans Energy Center North 138 kV Ckt 1 Rebuild	WERE	E	$22,687,706	12.2	NTC-C
Colbert 138 kV Capacitor	WFEC	R	$351,600		NTC
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps	KAMO (AECI)/ EMDE/SWPA	WW	$70,122,330	2	NTC-C / TBD
Conway - Kirby 115 kV Terminal Upgrade	SPS	O	$770,666		NTC
Crane Creek - Robinson Lake 115 kV New Line	BEPC	E/R	$16,392,701	2.4	NTC
Dawson County - Williston 230 kV Ckt 1 New Line	WAPA	R	$157,802,000	103.7	NTC-C
Delaware - Monett 345 kV Ckt 1 New Line	AEP/EMDE	WW	$342,608,905	114.5	NTC-C
Denver - Mid America 69 kV San Andreas - Seminole 115 kV Tap Intersection	SPS	R	$11,115,323		NTC
Edwardsville 161/115 kV Transformer	WERE	O	$6,345,206		NTC
Ellisville - Simpson 115 kV New Line, Zahl 115 kV Capacitor	MWEC	R	$18,488,763	15.6	NTC
Elm Creek - Tobias 345 kV New Line	ITC GP/NPPD	WW	$148,419,672	85.2	NTC-C
Evans Energy Center North - Halstead 138 kV Ckt 1 New Line	WERE	E	$39,683,130	17.4	
Farber - Sumner County No. 10 Belle Plain 138 kV Rebuild	WERE	E	$21,841,037	10.3	NTC-C
Finstad - Logan 345 kV New Line, Leland Olds - Logan 345 kV Voltage Conversion	BEPC	R	$313,662,135	129	NTC-C
Finstad - Satterwaite 115 kV New Line	MWEC	E/R	$19,838,462	12.6	NTC
Frankford - Quaker 115 kV Rebuild	SPS	R	$2,753,972	2	NTC
Gaines – Riley - Mid America - Mid-Denver Tap 69 kV Rebuild*	SPS	R	$7,339,941	6	NTC
Gering Tap - Morrill 115 kV Ckt 1 Rebuild	WAPA-RMR	E	$24,272,842	23.7	
Gering Tap - Scotts Bluff 115 kV Ckt 1 Rebuild	NPPD/ WAPA-RMR	E	$3,385,333	2	TBD
Grapevine - Kingsmill 115 kV New Line	SPS	R	$14,337,209	10.7	NTC
Hanson County 115 kV System Reconfiguration	EREC	R	$37,998,235	86.4	NTC-C
Harrisburg – Lincoln 115 kV Rebuild*	EREC	R	$3,755,542	3	NTC
Holcomb - Sidney 345 kV Ckt 1 New Line	BEPC/SUNC	O/WW	$887,460,816	300	NTC-C
Hoskins - Stanton North 115 kV Rebuild	NPPD	E	$4,000,000	9.9	NTC
Hutchinson 115 kV Capacitor*	EREC	R	$1,091,240		NTC
Iron House - Texaco 115 kV Ckt 1 New Line	LE-REC/SPS	R	$5,703,176	2.3	NTC
Kingsbury County 115kV Voltage Conversion	EREC	R	$84,007,000	96.9	NTC-C
Lamar 161/69 kV Ckt 2 Transformer	AECI	E	$7,641,150		

* FRA project

Description	Area	Type	Project Cost (2024$)	Miles	NTC/ NTC-C[14]
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild	WERE	E/R	$3,633,222	0.5	NTC
Lincoln – Sioux Falls 115 kV Terminal Equipment*	WAPA	R	$373,343		NTC
Logan - Magic City 230 kV Ckt 1 New Line	XEL/BEPC	R	$21,400,000	8.7	NTC-C / TBD
Lubbock East - Lubbock South 115 kV Terminal Equipment*	SPS	R	$956,448		NTC
Lynch - Medanos 115 kV Ckt 1 New Line	SPS	R	$50,631,694	17	NTC-C
Maddox - Pearle 115 kV Rebuild*	SPS	R	$15,972,706	15.3	NTC
Madison South Dakota Area 115 kV System Reconfiguration	EREC	R	$61,216,444	44	NTC
Marion South Dakota Area 115 kV Voltage Conversion	EREC	R	$67,814,174	90.1	NTC-C
Martin City (East) - Martin City (West) 161 kV Terminal Equipment	GMO	E	$3,060,219		NTC
Maud Tap 138 kV Terminal Upgrade	OGE	E	$425,503		NTC
Monett - North Branson 345 kV Ckt 1 New Line	EMDE	WW	$165,800,962	47.2	NTC-C
Moore County - XIT 230 kV Ckt 1 New Line	SPS	R	$52,830,105	46.2	NTC-C
Moore County 230/115 kV Ckt 2 Transformer*	SPS	R	$13,022,086.00		NTC-C
Morrill - Snake Creek 115 kV Ckt 1 Rebuild	WAPA-RMR	E	$9,596,378	8.9	TBD
Mount Vernon 115 kV Capacitor*	WAPA	R	$373,343		NTC
Muskogee - Tahlequah 161 kV rebuild, Muskogee - Fort Smith 345 kV Conversion/New Line[15]	OGE	E/O	$265,000,000	83	NTC-C
N Reeds Spring - S Reeds Spring 161 kV Rebuild	EMDE	WW	$3,266,430	1.5	NTC
Nashua 345/161 kV Ckt 2 Transformer	EM	E/O	$24,750,244		NTC-C
Ozark Dam - Forsyth North - Ozark South 161 kV Voltage Conversion	EMDE	WW	$38,032,729	28.2	NTC-C
Patent Gate - Pioneer 345 kV Ckt 1 New Line	BEPC	R	$163,714,033	33.5	NTC-C
Phantom - Crossroads - Potter 765 kV Ckt 1 New Line	SPS	E/R	$1,690,874,827	293	NTC-C
Pioneer - Sanderson 115 kV Ckt 1 New Line	MWEC	E/R	$15,299,934	10.1	NTC
Ren - Williston 115 kV Rebuild*	WAPA	R	$9,398,047	8.7	NTC
Roadrunner 345/115 kV Ckt 2 Transformer	SPS	R	$19,997,839		NTC
Roadrunner 345/115 kV Ckt 3 Transformer	SPS	E/R	$19,997,839		NTC
S1260 161 kV Breaker Replacement	OPPD	SC	$1,273,928		
S3458 - S3740 345 kV Ckt 2 New Line	OPPD	E/R	$98,650,000	33	NTC-C
Sioux Falls South Dakota Area 115 kV System Reconfiguration	EREC/WAPA	R	$25,374,827	9.1	NTC-C
Spencer - Widsom 69 kV Rebuild*	WAPA	R	$1,020,175	0.5	NTC
Spring Brook - Twelve Mile 345 kV Ckt 1 New Line	BEPC	R	$81,116,918	12	NTC-C
Sub 1209 - Sub 1250 161 kV Rebuild	OPPD	R	28366729	7.8	NTC-C
Sub 1209 - Sub 1358 161 kV Rebuild	OPPD	R	1661726	4.8	NTC

* FRA project

[15] Project added to the final portfolio after the final consolidated portfolio was aggregated

Description	Area	Type	Project Cost (2024$)	Miles	NTC/ NTC-C[14]
Sub 1250 - Sub 1358 161 kV Rebuild	OPPD	R	1813726	4.7	NTC
Tallgrass - Weaver 138 kV Rebuild	EKC	E	$11,986,623	9.8	NTC
Tinker 138 kV Two Breaker Replacements	OGE	SC	$600,000		NTC
Tulsa North 345/138 kV Ckt 2 Transformer	AEP	E	$13,022,086		NTC
W Banks 345/115 kV Transformer	BEPC	E/R	$50,776,906		NTC-C
Wisdom 161/69 kV Transformer	WAPA	R	$7,641,150		
		Total:	$7,681,809,685		

Table 1.1 Final Portfolio and NTC Recommendations

Figure 1.1 depicts the 2024 ITP thermal/voltage reliability projects.

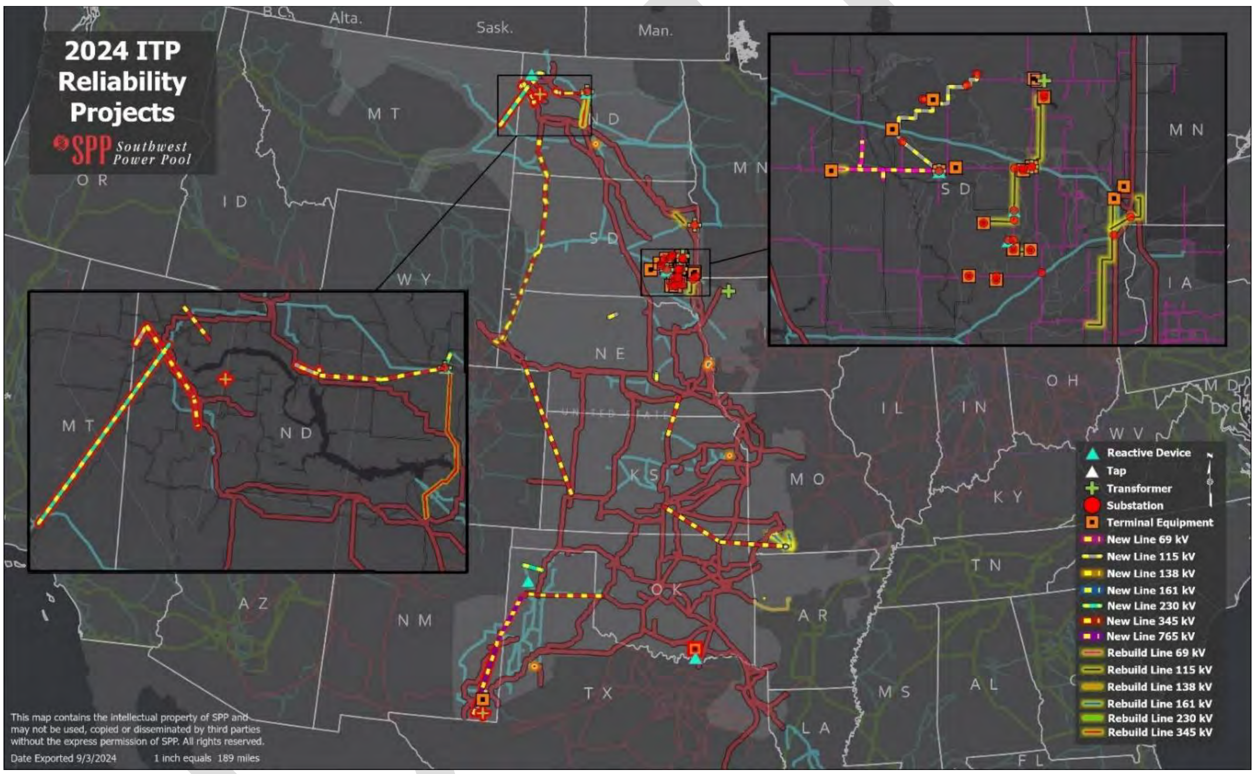

Figure 1.1: 2024 ITP Thermal & Voltage Reliability Projects

Figure 1.2 depicts the 2024 ITP short circuit reliability projects.

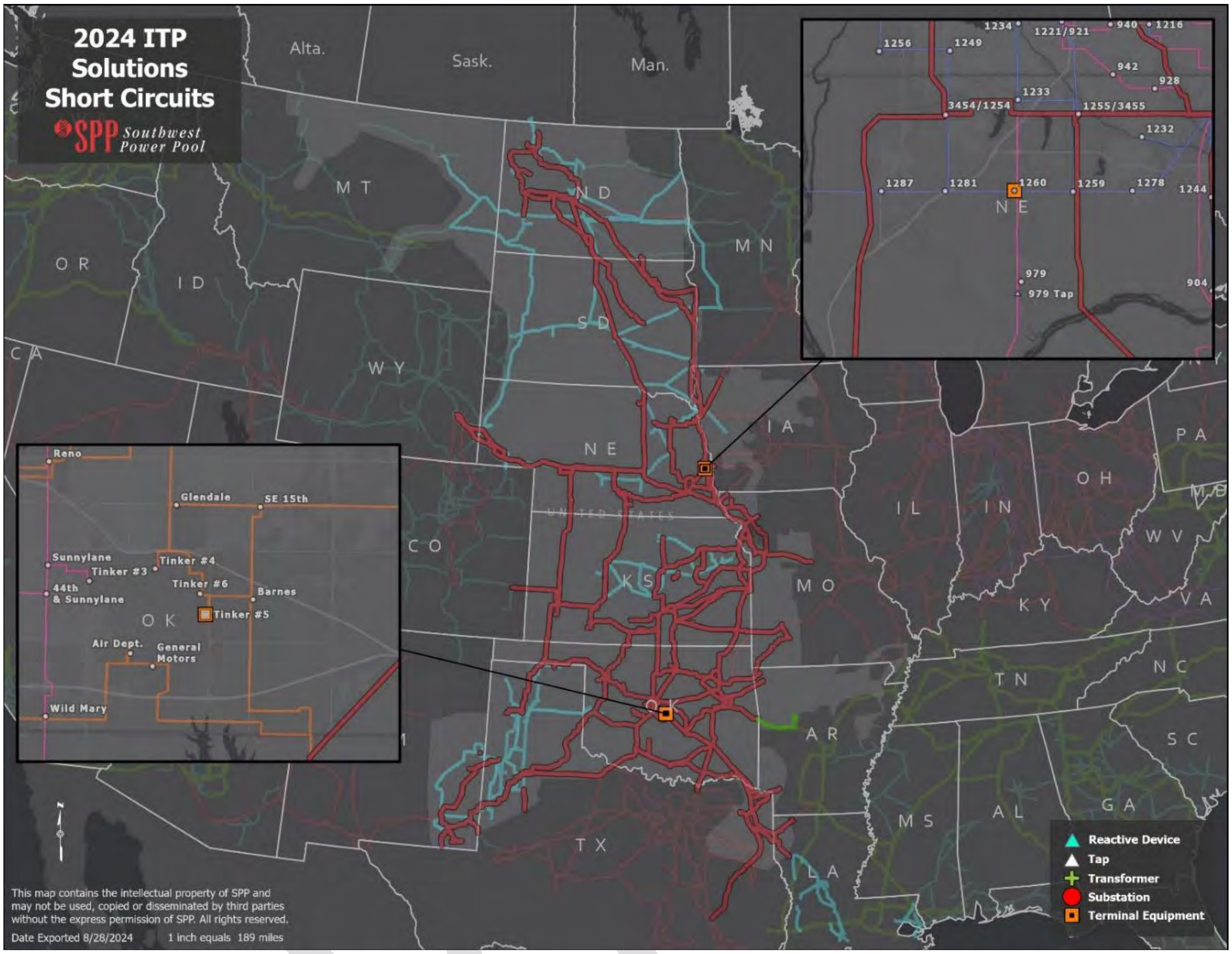

Figure 1.2: 2024 ITP Short Circuit Reliability Projects

Figure 1.3 depicts the 2024 ITP winter weather projects.

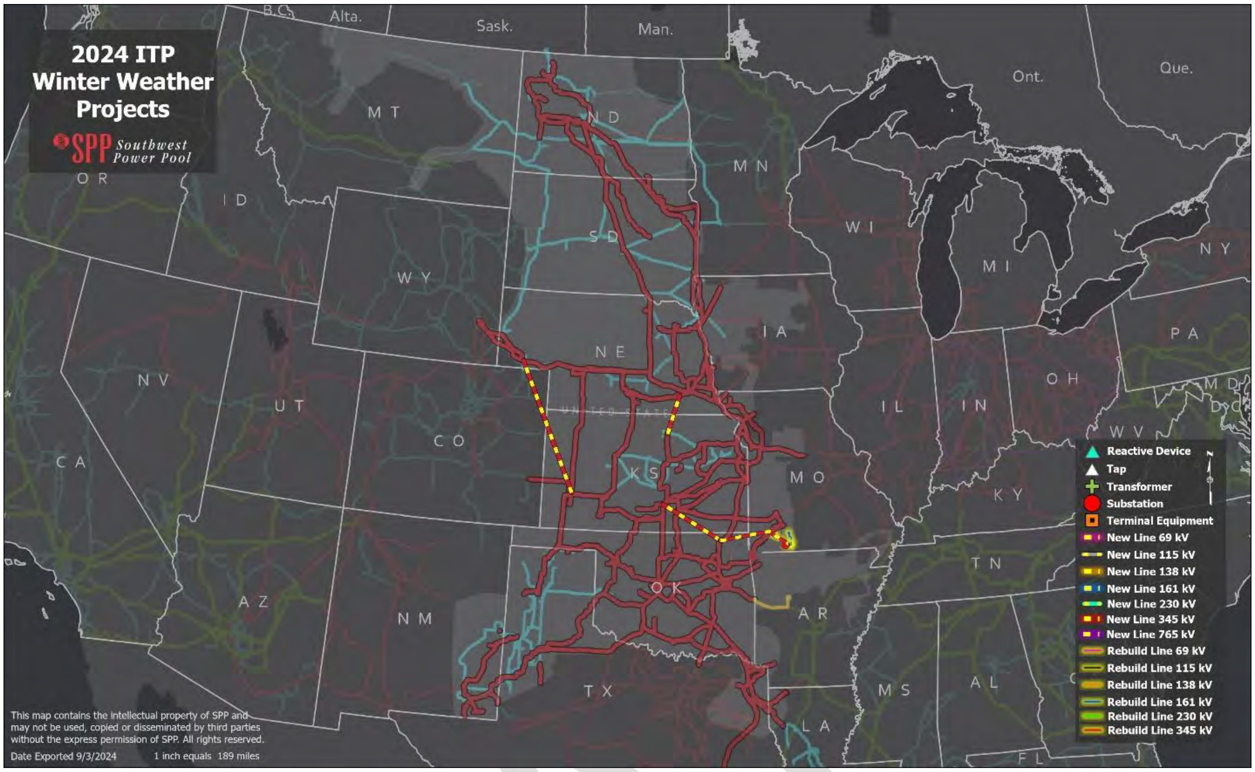

Figure 1.3: 2024 ITP Winter Weather Projects

Figure 1.4 depicts the 2024 ITP economic projects.

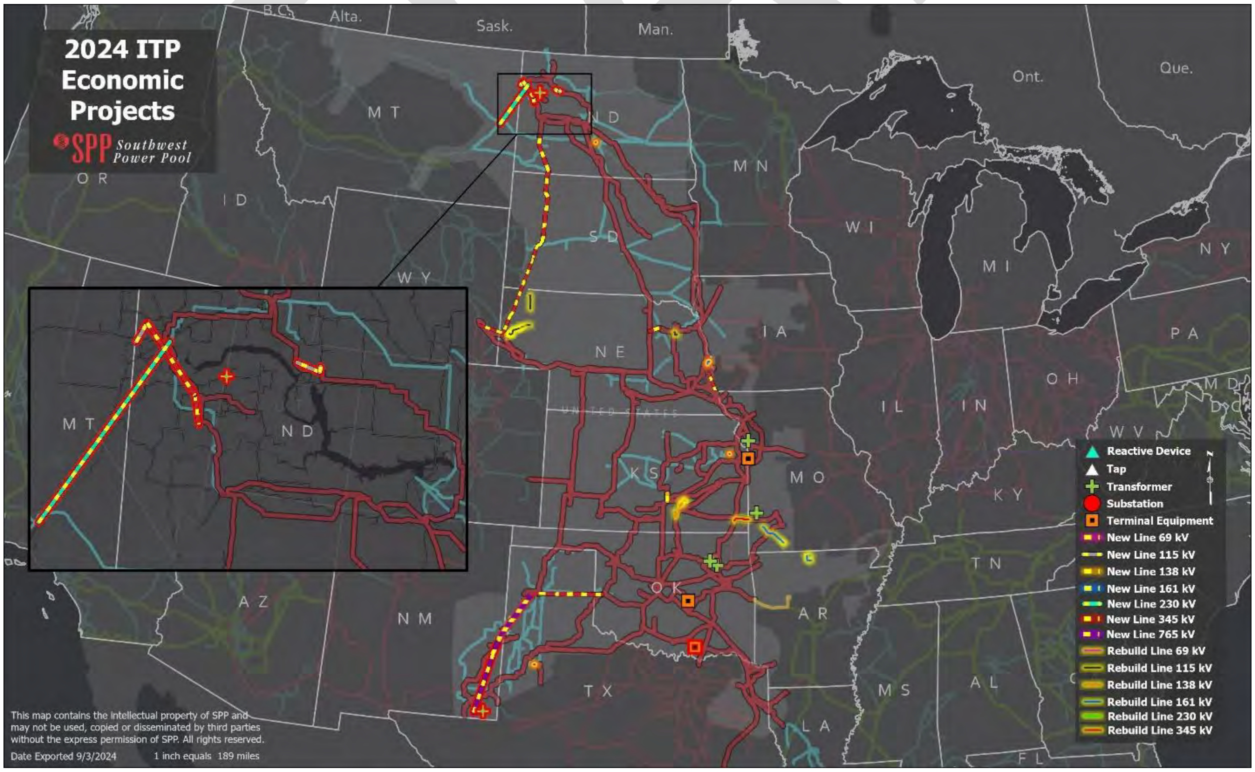

Figure 1.4: 2024 ITP Economic Projects

2 STUDY DRIVERS

As previously noted, the significant transmission buildout of the 2024 ITP is the largest portfolio of solutions ever recommended by SPP. The recommended portfolio is a result of three major study drivers:

- Load growth
- Extreme winter weather scenario evaluation
- Continued renewable growth

2.1 LOAD GROWTH

Load growth, by nature, can be cyclical, with periods of minimal load growth followed by years with significant load growth. The 2024 load forecast marked a shift from a period of minimal load growth[16] to a new point in time where new load customers are asking to be connected to the electric grid as quick as possible. Over recent years two key areas have exhibited higher-than-average load growth. Those areas are New Mexico and the Williston, North Dakota areas. Oil and gas developments in these areas are creating load growth, which is in turn, driving the need for transmission investment. Currently, SPP is experiencing rapid load growth in more than these two areas of its footprint, especially with large single spot loads.

For the 2024 ITP, SPP measured a significant increase in both summer and winter seasons. Comparing the 2023 and 2024 ITP load forecasts provides several key data points:

- 2024 ITP year two summer load forecast is higher than the 2023 ITP summer year 10 load forecast by more than 600 megawatts.
- 2024 ITP year two winter load forecast is higher than the 2023 ITP winter year 10 load forecast by more than 1,500 MW.
- 2024 load forecast for year 10 is 9.7% and 12.9% higher, for summer and winter, respectively.

This trend continues with the 2025 ITP load forecast which has already been approved by SPP stakeholders and has received incremental updates. The following chart compares the summer and winter load forecasts for the 2023, 2024 and 2025 ITP Assessments. These load additions are a major driver of the first 765 kV project SPP has recommended for NTC issuance.

[16] The 2022 and 2023 ITP load forecasts were developed during the 2020 and 2021 calendar years, respectively.

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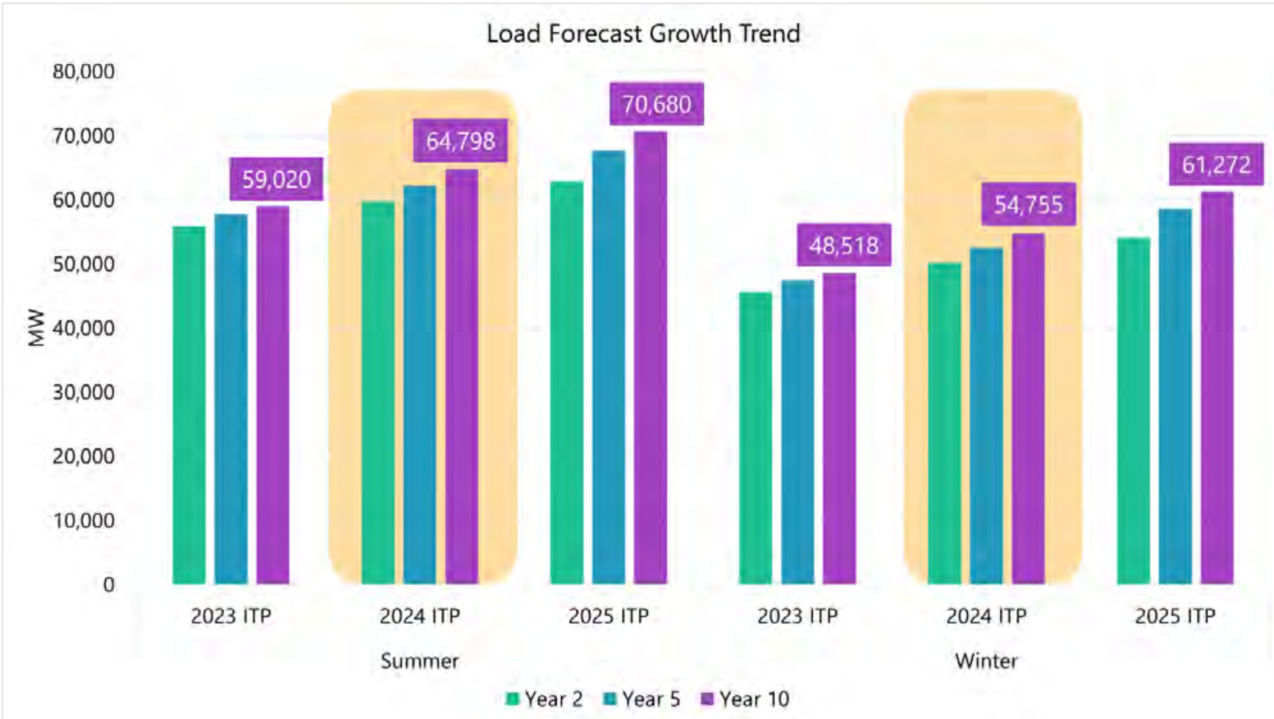

Figure 2.1: Load Forecast Growth Trend

Concentrated load growth observed in the load forecast comparison map below can severely stress the transmission system by using up remaining transmission system capacity to a delivery point or lowering voltage with large power transfers over long distances to reach load pockets. In some cases, the energy needs driven by large spot load growth are more than the available transmission capacity currently available to that location.

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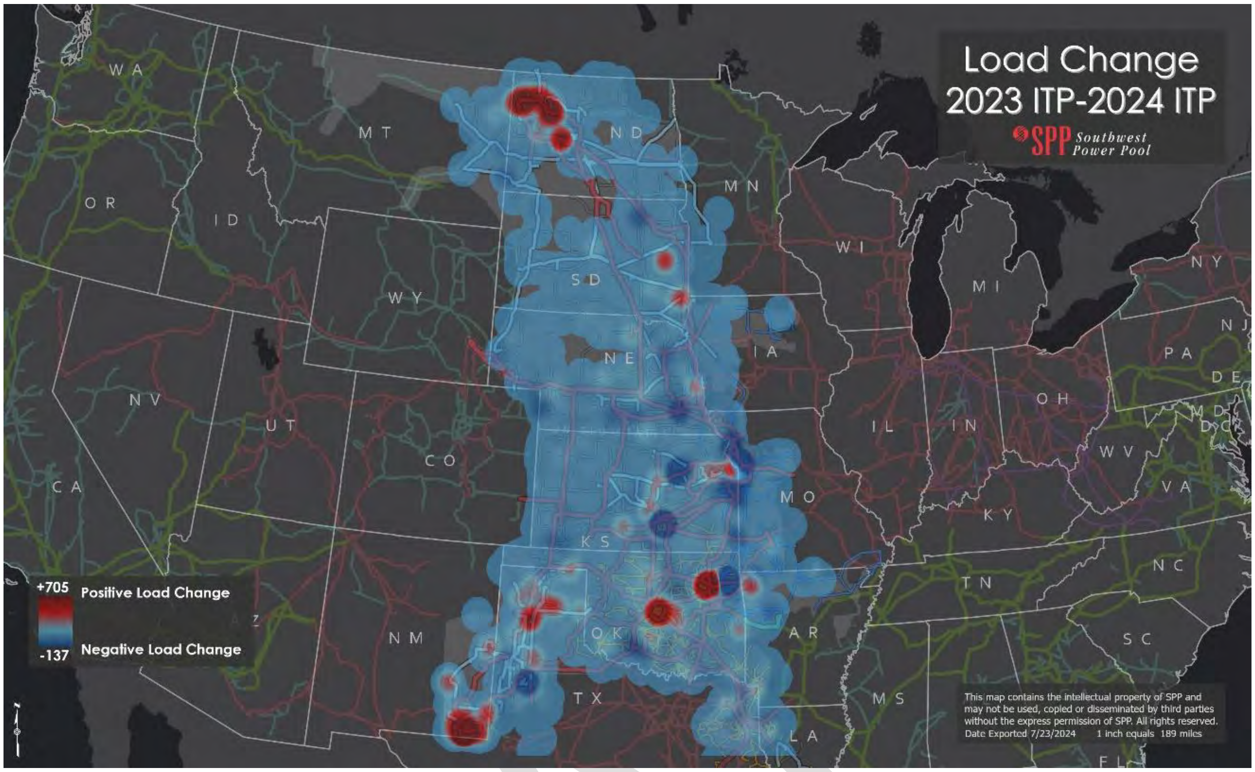

Figure 2.2: Load Comparison of 2023 ITP and 2024 ITP

The significant load growth in the SPP footprint is a major driver of the transmission needs recommended in this study. This point is further illustrated in the Sensitivity Analysis in Section 7.4, specifically Figure 7.3, where adjusting the demand in the economic models with a high and low demand sensitivity generates the largest change in benefits.

2.2 EXTREME WINTER WEATHER PLANNING

During the 2021 and 2022 winters, two winter storms impacted the SPP footprint leading to multiple load shed events.[17]

Winter Storm Uri was a multi-day storm stressing the grid with low temperatures stretching from the Canadian border into the Texas panhandle. Extended cold temperatures led to significant energy usage, fuel availability issues, and impacts to transmission and generation facilities leading to the first RTO-directed load shed in SPP's history.

Not long after Uri, Winter Storm Elliott affected much of the same portion of the country and SPP footprint. Although the storm lasted a shorter period, the SPP footprint was still heavily stressed. Higher wind levels during this storm led to more extreme wind chill and, ultimately, higher loads. Additionally, the increase in wind forecast led to more congestion moving from west to east into Missouri. This

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[17] For more information on each winter storm, please review the individual reports reviewing SPP's response to these weather events on SPP.org. February 2021 Event: Winter Storm Uri report and December 2022 Event: Winter Storm Elliott report.

increase congestion and other weather-related facility outages led one of SPP's member companies to mitigate low voltages on their systems with TO directed load shed.

After Winter Storm Elliott, SPP and its members began discussions on incorporating extreme winter weather planning into the SPP planning processes. This resulted in an action item from the January 18-19, 2023, Strategic Planning Committee (SPC) meeting.[18] The action item directed "*staff to work with stakeholders to implement approaches for considering extreme weather events in the 2024 ITP scope*".

As a result of this action item from the SPC, SPP staff created a Winter Weather Strike Team (WWST) made up of interested stakeholders to support model development and analysis methodologies. The WWST met for two hours weekly for most of the 2023 calendar year to brainstorm the optimal approach to evaluate extreme winter weather as a meaningful input into the 2024 ITP.

After significant staff and stakeholder collaboration, SPP brought the revised 2024 ITP scope to the April 10-11[t], 2023, Market and Operations Policy Committee meeting for approval. Revisions to the 2024 ITP scope also identified a Target Area consisting of south and south-central Missouri, northwest Arkansas, and southeast Kansas. This target area includes facilities where the TO-directed load shed occurred in December 2022. Another determining factor for the identification of this target area was the significant congestion identified in the 2024 ITP constraint assessment. Detailed information on the extreme winter weather model development and analysis can be found in section 3.4.

2.3 RENEWABLE GROWTH

The last major study driver for the 2024 ITP is the significantly increased renewable assumptions. Past ITP reports have shown that renewable generation growth within SPP was under-forecasted when comparing study assumptions with installations over time. The 2024 ITP took a significant step forward with renewable assumptions. Figure 2.3 compares the 2023 ITP and 2024 ITP renewable amounts. The darker bar graph represents the 2023 ITP, and the brighter color represents the 2024 ITP.

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[18] https://www.spp.org/documents/68713/spc%20minutes%2020230118-19%20v3.pdf

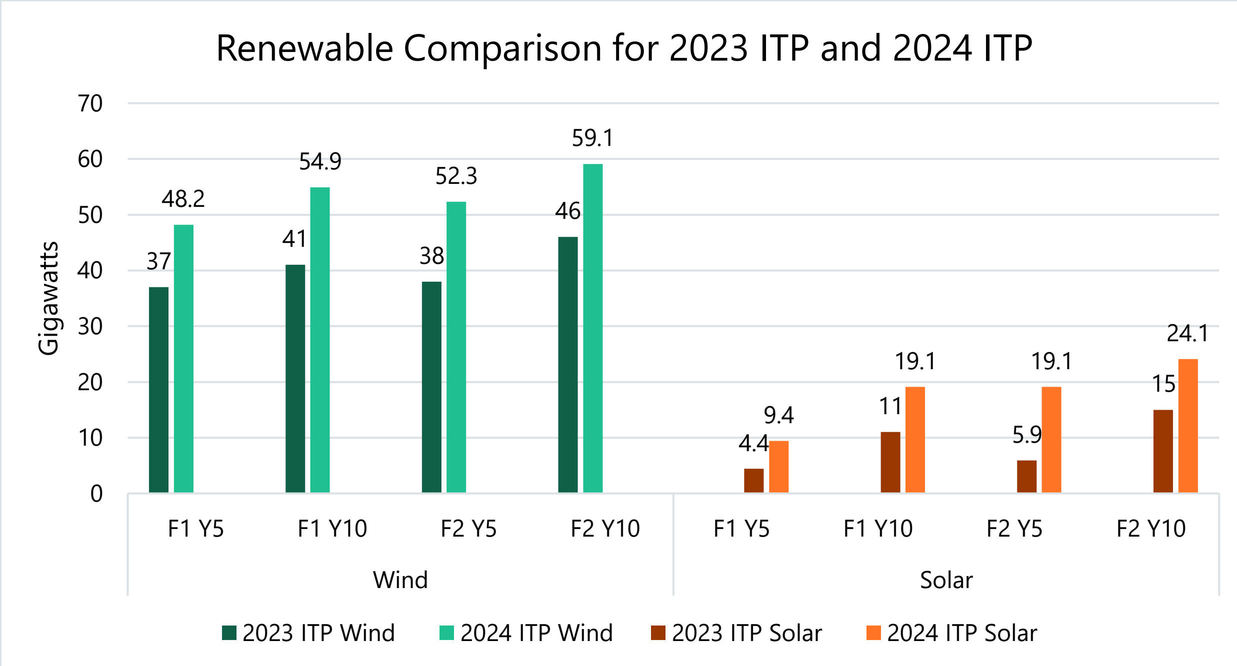

Figure 2.3: Renewable Generation Comparison of the 2023 ITP and 2024 ITP

For the 2024 ITP, wind amounts averaged 33% higher for each scenario. Solar amounts also increased significantly, especially in year five. Increased renewable energy in the ITP models can result in increased congestion when low-cost energy is plentiful on the system. This is especially noticeable during the nighttime hours when wind blows more, and load is reduced compared to daytime hours.

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3 MODEL DEVELOPMENT AND BENCHMARKING

3.1 BASE RELIABILITY MODELS

3.1.1 GENERATION AND LOAD

SPP staff incorporated the generation and load data in the 2024 ITP base reliability models based on specifications documented in the ITP Manual. For items not specified in the ITP Manual, SPP followed the SPP Model Development Advisory Group (MDAG) Procedure Manual.[19] Renewable dispatch amounts are based on historical averages for resources with long-term firm transmission service for the summer and winter seasons. For the light load models, SPP staff dispatched all wind resources with long-term firm transmission service to the lesser of the full long-term firm transmission service amount or nameplate amount, with remaining generation coming from conventional resources. In these base reliability models, all entities are required to meet their non-coincident peak demand with firm resources.

Section 3.5.1 details the generation dispatch and load in the base reliability models.

3.1.2 TOPOLOGY

Topology data in the 2024 ITP base reliability models includes the existing transmission system, existing NTC/NTC-C's, outage data according to TPL Standards and the 2022 ERAG MMWG model set with updates from First Tier External Areas. For items not specified in the ITP Manual, SPP followed the MDAG Model Development Procedure Manual. The topology for areas external to SPP was consistent with the 2022 Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group (MMWG) model series.

Additional voltage support was necessary in the base 2033 Winter case to allow for the model to reach a converged solution. The inclusion of the 2024 ITP Portfolio into the model set allows for this additional voltage support to be removed.

[19] Model Development Advisory Group (MDAG) Procedure Manual; the MDAG Procedure Manual may differ throughout the study process. The version that was current at the time of the study was used.

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3.1.3 SHORT-CIRCUIT MODEL

SPP developed a short-circuit model, representative of the year two, summer peak, for short-circuit analysis. Within the short-circuit model, all modeled generation and transmission equipment is modeled as in service to simulate the maximum available fault current, excluding exceptions such as normally open lines or retired generation. This model was analyzed in consideration of the North American Electric Reliability Corporation (NERC) TPL-001 standard.[20]

3.2 MARKET MODEL INPUTS

3.2.1 MODEL ASSUMPTIONS AND DATA

3.2.1.1 *FUTURES DEVELOPMENT*

The ESWG developed two futures with input from the Strategic Planning Committee (SPC) and TWG. The MOPC reviewed draft futures in October 2022 and finalized them in January 2023.

Table 3.1 summarizes the drivers and how SPP considered them in each future.

	Drivers		
Key Assumptions	**Year 2**	**Future 1 – Reference Case** **Year 5 Year 10**	**Future 2 – Emerging Technologies** **Year 5 Year 10**
Peak Demand Growth Rates	As submitted in load forecast	Increase due to electric vehicle growth	Higher Increase due to electric vehicle growth
Energy Demand Growth Rates	As submitted in load forecast	Increase due to electric vehicle growth	Higher Increase due to electric vehicle growth
Natural Gas Prices	Current industry forecast	Current industry forecast	Current industry forecast
Coal Prices	Current industry forecast	Current industry forecast	Current industry forecast
Emissions Prices	Current industry forecast	Current industry forecast	Current industry forecast
Fossil Fuel Retirements	Current forecast	based on IRP feedback; subject to generator owner (GO) review	based on IRP feedback; subject to generator owner (GO) review
Environmental Regulations	Current regulations	Current regulations	Current regulations
Demand Response[21]	As submitted in load forecast	As submitted in load forecast	As submitted in load forecast

[20] NERC Standard TPL-001-5 Transmission System Planning Performance Requirements

[21] As defined in the SPP Model Development Procedure Manual

	Drivers				
Key Assumptions	**Year 2**	**Future 1 – Reference Case**		**Future 2 – Emerging Technologies**	
		Year 5	**Year 10**	**Year 5**	**Year 10**
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Storage	Existing + RARs	*30% of projected solar* (2.8. GW / 5.7 GW)		*40% of projected solar* (7.6 GW / 9.6 GW)	
Total Renewable Capacity					
Solar (GW)	Existing + RARs	9.4	19.1	19.1	24.1
Wind (GW)	Existing + RARs	48.2	54.9	52.3	59.1

Table 3.1: Future Drivers

3.2.1.2 *LOAD AND ENERGY FORECASTS*

The 2024 ITP load review focused on load data through 2033. The load data was derived from the base reliability model set, and stakeholders were asked to provide updates to the following parameters:

- Assignment of loads to companies
- Forecasted system peak load (MW)
- Loss factors
- Load factors
- Load demand group assignments
- Monthly peak and energy allocations
- Station service loads
- Resource planning peak loads and load factors

The ESWG and TWG-approved load review was used to update the load information in the market economic models. Figure 3.1 shows the total coincident peak load for each study year. Figure 3.2 shows the monthly energy and annual coincident peak per future for each study year (2025, 2028, and 2033).

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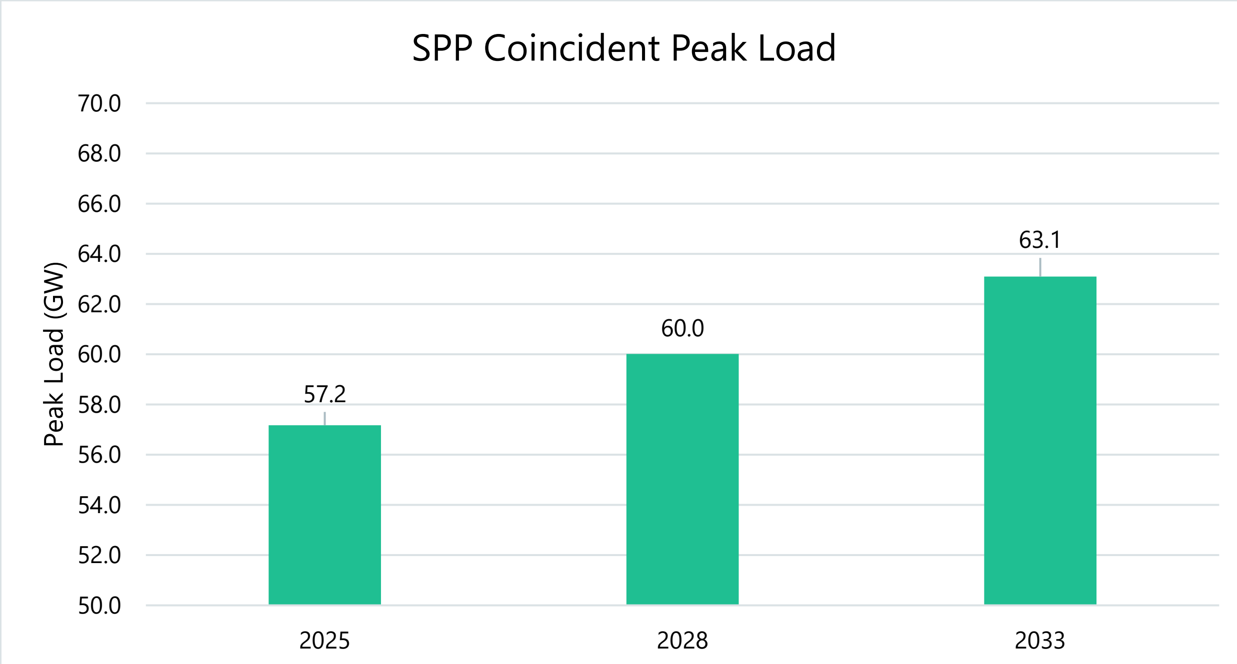

Figure 3.1: Coincident Peak Load

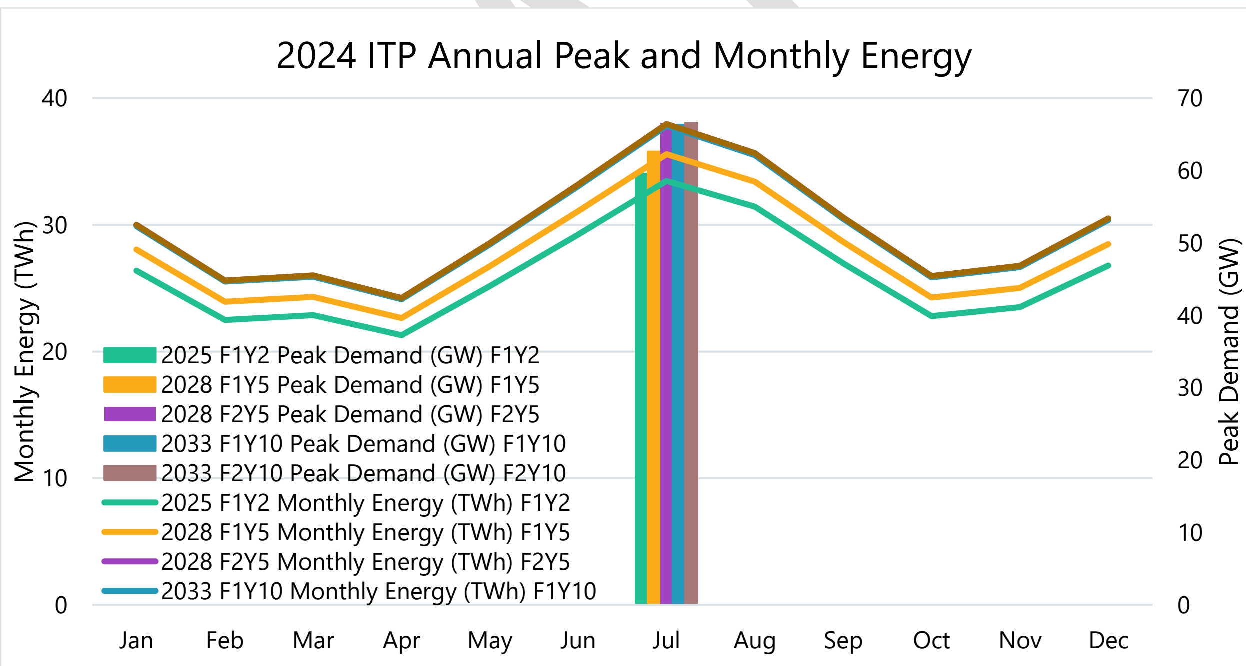

Figure 3.2: 2024 ITP Annual Peak and Monthly Energy

3.2.1.3 *RENEWABLE POLICY REVIEW*

Renewable policy requirements enacted by state laws, public power initiatives and courts are the only public policy initiatives considered in this ITP via the renewable policy review (RPR). The ITP Manual defines these requirements as percentages. The CAWG and ESWG approved deviations from the renewable policy standards (RPS) for Montana, Oklahoma, and Colorado. The Montana legislature repealed the renewable standard that was previously enacted, so this standard was removed from the

RPS. Oklahoma and Colorado were added to the RPS list to ensure SPP captured all possible goals. The 2024 ITP RPR focused on renewable requirements through 2033.

State	RPS Type	Generation Type[22]	Capacity- or Energy- Based	Statewide or by utility?	Year 5	Year 10
Kansas	Goal	Both	Capacity (MW)	Utility	20%	20%
Minnesota	Mandate	Both	Energy (MWh)	Utility	25%	25%
Missouri	Mandate	Both	Energy (MWh)	Utility	15%	15%
New Mexico	Mandate	Both	Energy (MWh)	Utility	40%	50%
North Dakota	Goal	Both	Energy (MWh)	State	10%	10%
Oklahoma	Goal	Both	Capacity (MW)	State	15%	15%
South Dakota	Goal	Both	Energy (MWh)	State	10%	10%
Texas	Mandate	Both	Capacity (MW)	State	5%	5%
Colorado	Mandate	Both	Energy (MWh)	Utility	30%	30%

Table 3.2: Renewable Policy Review Table

3.2.1.4 *GENERATION RESOURCES*

SPP supplemented existing generation data originated from the Hitachi Simulation Ready Data Fall 2021 Reference Case with SPP stakeholder information provided through the SPP Model on Demand tool and the generation review.

Figure 3.3 and Figure 3.4 detail the annual nameplate capacity and energy by unit/fuel type, respectively for 2025, 2028 and 2033 for Future 1, and 2028 and 2033 for Future 2.

In addition to resources accepted in the base reliability models, stakeholders were given the chance to request additional generation resources in the ITP models through the Resource Addition Request (RAR) process and the SPP RAR process. As a result of the RAR process, 2.21 gigawatts of wind generation and 1605 megawatts of solar generation was added to the market economic models.

Generator operating characteristics, such as operating and maintenance (O&M) costs, heat rates, and energy limits were also provided for stakeholders to review.

[22] A generation type of "Both" indicates that it can be met by wind and/or solar resources.

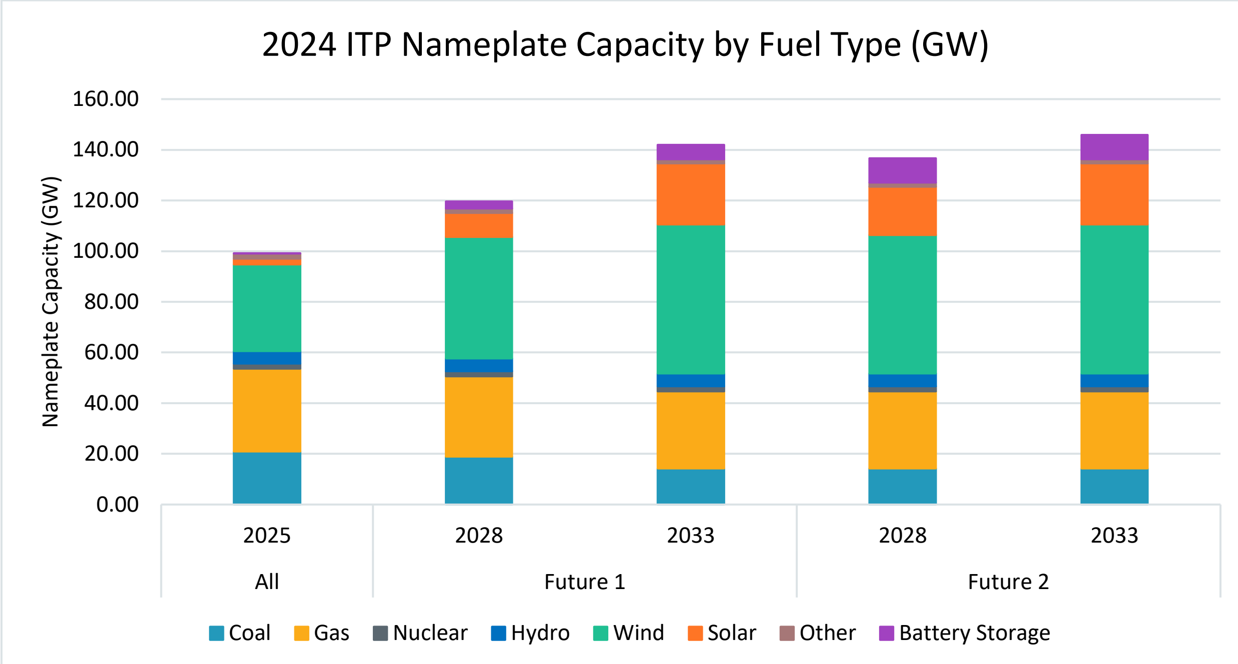

Figure 3.3: Nameplate Capacity by Fuel Type

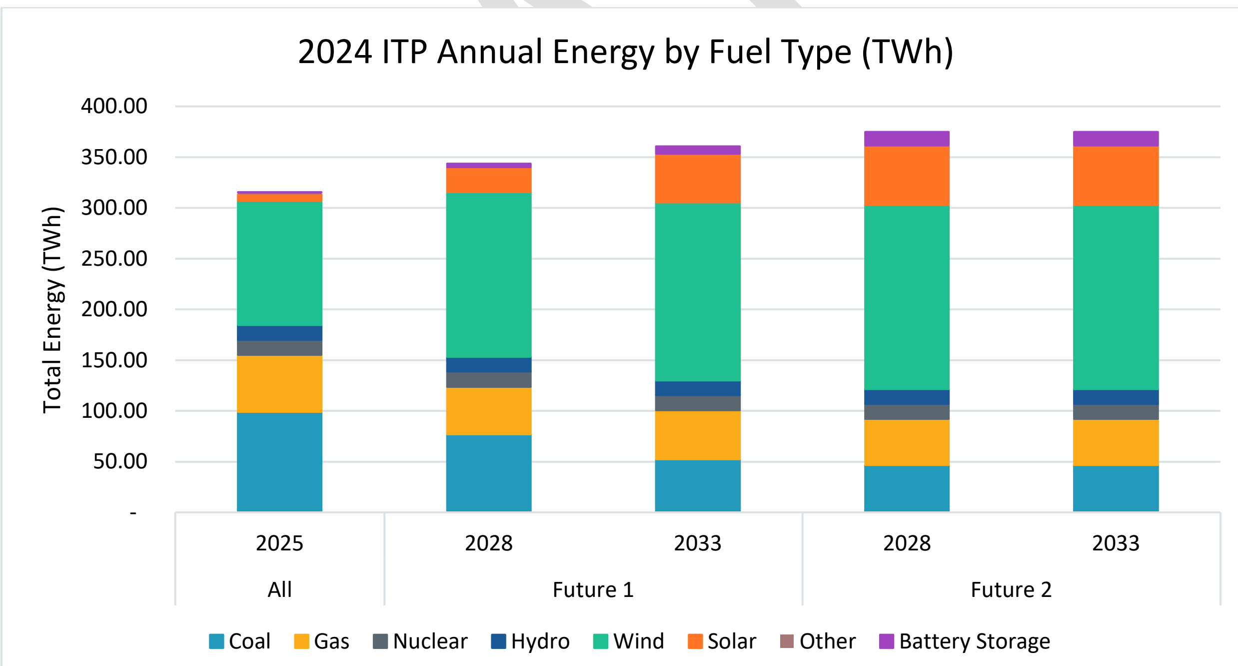

Figure 3.4: Annual Energy by Fuel Type (TWh)

Figure 3.5 identifies the amount of planned conventional generation retirements used in the 2024 ITP Assessment shown by future and by year.

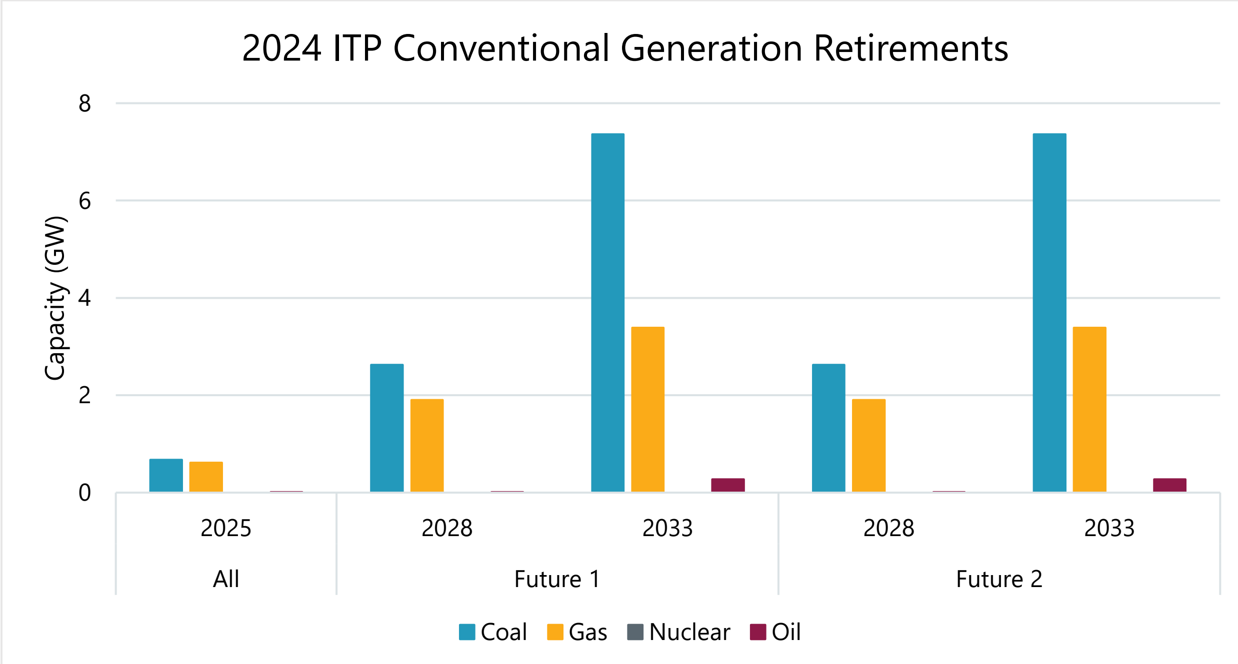

Figure 3.5: Conventional Generation Retirements (GW)

3.2.1.5 *FUEL PRICES*

To develop the fuel price forecast, SPP utilized the Hitachi Simulation Ready Data Fall 2021 Reference Case, Hitachi fundamental forecast (for long-term natural gas price projections), and S&P Global Composite Insights fundamental forecast (for long-term natural gas prices projections). SPP averaged the Hitachi and S&P Global Composite Insights fundamental forecasts for the average natural gas prices. Figure 3.6 shows the annual average natural gas and coal prices for the study horizon. Between 2024 and 2034, these prices increase from \$3.36 to \$5.75 (~4.8 % compound average escalation) and \$2.39 to \$3.03 (~1.8 % compound average escalation) for natural gas and coal, respectively.

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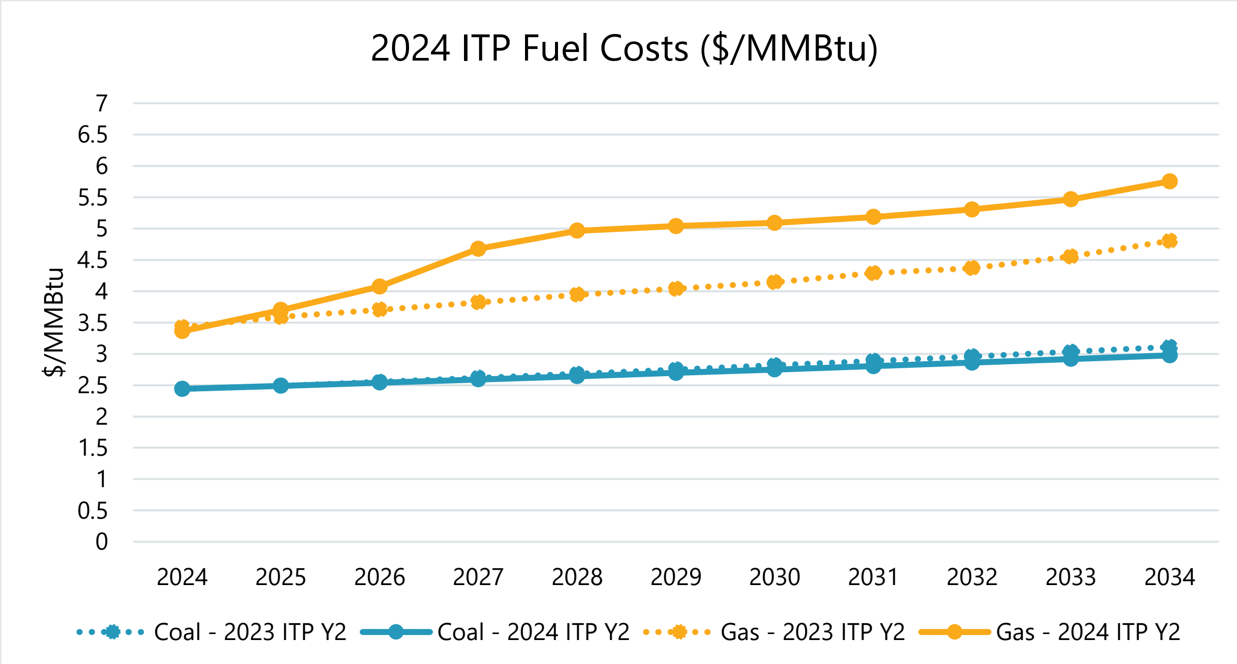

Figure 3.6: Fuel Annual Average Fuel Price Forecast

3.2.2 RESOURCE PLAN

SPP begins the important task of evaluating transmission over a 10-year horizon by identifying the resource outlook for each future. The SPP generation portfolio will evolve over the next 10 years due to the changing load forecasts, resource retirements and fast-changing mix of resource additions. SPP developed resource expansion plans to meet renewable portfolio standards, resource reserve margin requirements, and future specific renewable and emerging technology projections.

3.2.2.1 *RENEWABLE RESOURCE EXPANSION PLAN*

SPP analyzed each utility to determine if the assumed renewable mandates and goals identified by the renewable policy review could be met with existing generation and initial resource projections for 2028 and 2033. If the analysis projected that a utility would be unable to meet requirements, SPP assigned additional resources to the utilities from the total projected renewable amounts to meet renewable portfolio standards. For states with a standard that could be met by either wind or solar generation, a ratio of 50% wind additions to 50% solar additions was utilized. This split was representative of the active GI queue requests for wind and solar resources.

The incremental renewables assigned to meet renewable mandates and goals in the SPP footprint by 2033 are shown in Figure 3.7.

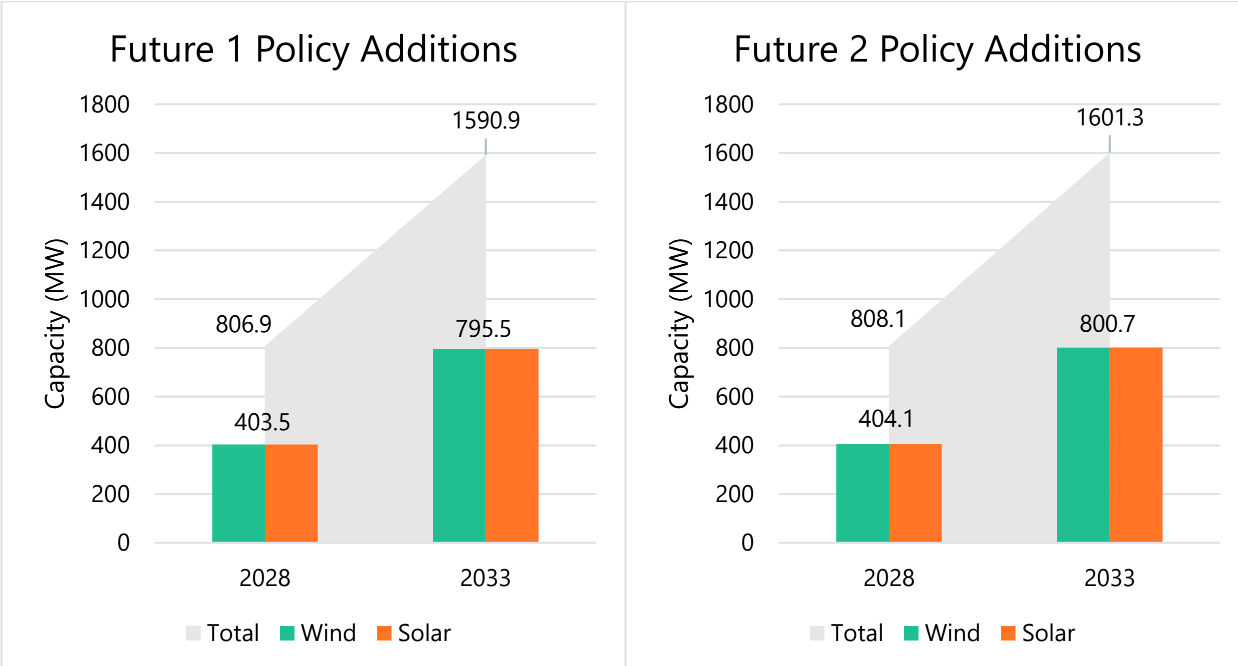

Figure 3.7: SPP Renewable Generation Assignments to meet Mandates and Goals

After SPP ensured renewable portfolio standards were met by assigning renewables, SPP accredited the remaining projected renewable capacity to each pricing zone.

SPP also accredited projected wind and solar additions to deficient zones to maximize the available accreditation of renewables for each zone. Resources were accredited in the following order:

- Existing generation
- Policy wind and solar additions
- Projected solar additions
- Projected storage additions
- Projected wind additions
- Conventional additions

3.2.2.2 *CONVENTIONAL RESOURCE EXPANSION PLAN*

SPP used the renewable resource expansion plan for each future as an input to the corresponding conventional resource expansion plan to ensure appropriate resource adequacy within the SPP footprint.

SPP calculated projected reserve margins for each pricing zone using existing generation, future-specific retirements, projected renewable generation, fleet power purchase agreements, and load projections through 2040.

SPP counted nameplate conventional generation capacity assigned to pricing zones toward each zone's capacity margin requirement.

For the 2024 ITP, SPP determined total accreditation values for wind, solar and energy storage by each resource type's effective load-carrying capability (ELCC). The ELCC is defined by SPP's Resource Adequacy department based upon the nameplate values from the 2024 ITP scope. ELCC identifies the capacity value of resources by determining the amount of load the resources will be able to serve during peak hours. These accreditation amounts are shown below in megawatts in Table 3.3.

Resource Type	F1 Y5		F1 Y10		F2 Y5		F2 Y10	
	Scoped Amount	ELCC Amount	Scoped Amount	ELCC Amount	Scoped Amount	ELCC Amount	Scoped Amount	ELCC Amount
Wind	48,200	7,278	54,900	7,686	52,300	7,845	59,100	7,683
Solar	9,400	6,110	19,100	9,932	19,100	9,932	24,100	9,640
Energy Storage	2,800	2,735	5,700	5,100	7,600	6,647	9,600	6,073

Table 3.3: 2024 Total Accreditation for Wind, Solar and Energy Storage (MW)

Before assigning each zone accreditation from the renewable resource plan, SPP reduced the ELCC amounts by the amount of firm service determined in the generation review. For this cycle, the allocation methodology considered resource planning templates provided by stakeholders. In this instance, the planned resources, according to template responses, were less than the scoped resources which put allocation in an excess scenario. As a result, responding companies received the full amount of renewable MWs requested in their resource planning template. The remaining ELCC was allocated to non-responding companies pro rata (all fuel types) based upon shortfall, capped at 15% planning reserve margin (PRM). If a zone did not ultimately meet its PRM, SPP staff determined it had a zonal shortfall and assigned it conventional capacity from the Conventional Resource Plan. In the 2024 ITP, SPP did not allocate conventional capacity, all utilities met the PRM with available scoped renewable resources.

Figure 3.8 shows nameplate generation additions by future, study year and technology for the SPP region while Figure 3.9 shows accredited generation. These values are not incremental.

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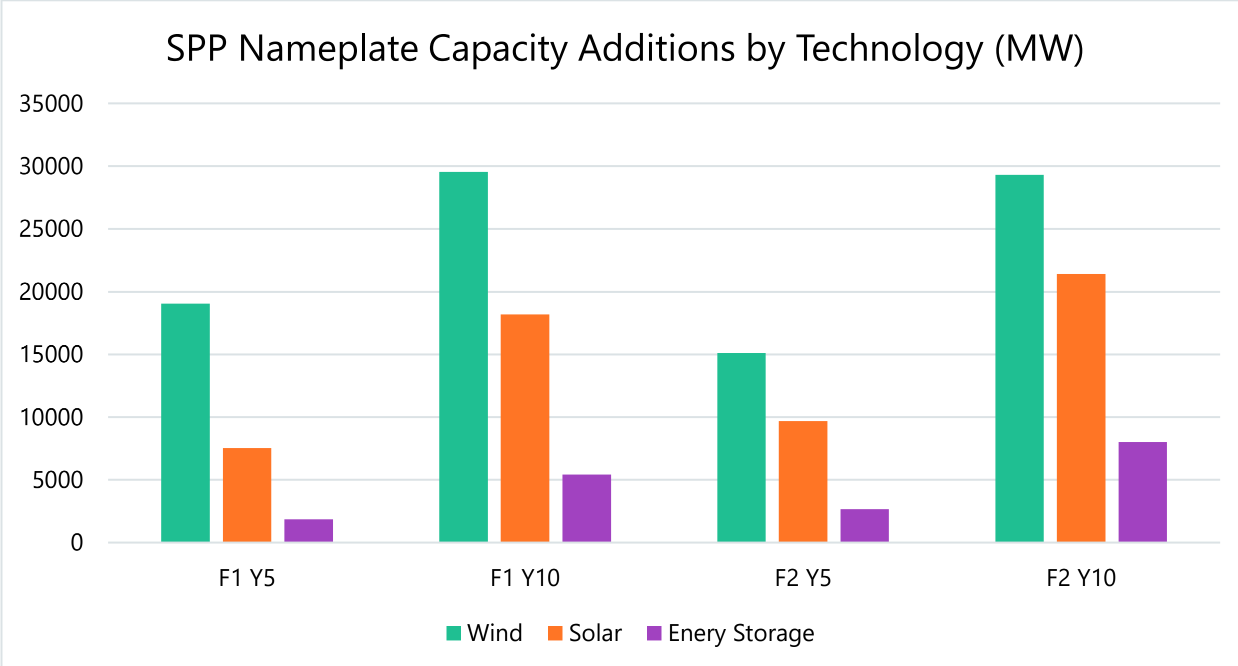

Figure 3.8: SPP Nameplate Capacity Additions by Technology (MW)

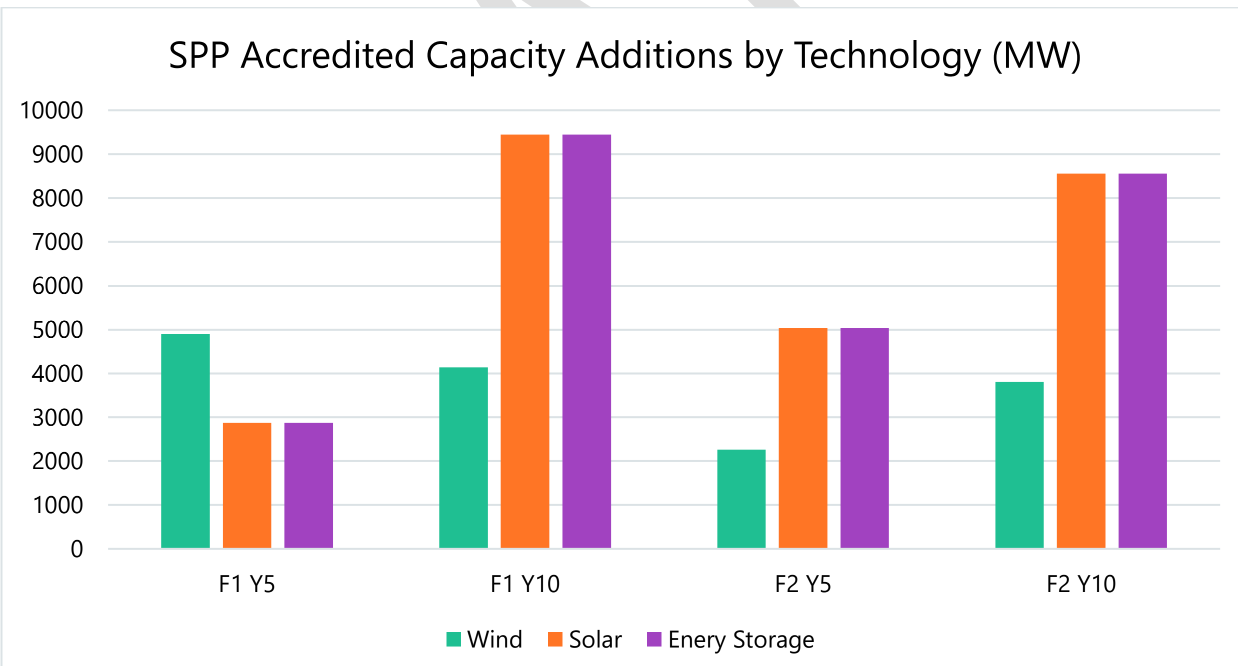

Figure 3.9: Accredited Capacity Additions by Technology (MW)

3.2.2.3 *SITING PLAN*

SPP sited projected renewable resources including wind, utility solar, and battery units, according to various site attributes for each technology in accordance with the ITP Resource Siting Manual.[23] Due to

[23] Documented in the ITP Resource Siting Manual

the generation amounts approved in the 2024 ITP scope being sufficient, no conventional units were included in the 2024 ITP Resource Siting Plan.

3.2.2.3.1 SOLAR SITING

Utility-scale solar was sited according to:

- Allocated generation to each zone as determined by the load-ratio share method
- Data Source (given preference in the following order)
  - SPP and Integrated System (IS) GI queue requests
  - Stakeholder submitted sites
  - Previous ITP sites
  - Other National Renewable Energy Laboratory (NREL) conceptual sites
- Capacity factor
- Generator transfer capability of the potential sites

Following the implementation of this ranking criteria, stakeholders could request exceptions to the results, which SPP reviewed for potential inclusion in the siting plan. Figure 3.10 through Figure 3.13 show the selected sites and allocation of utility solar capacity across the SPP footprint in megawatts.

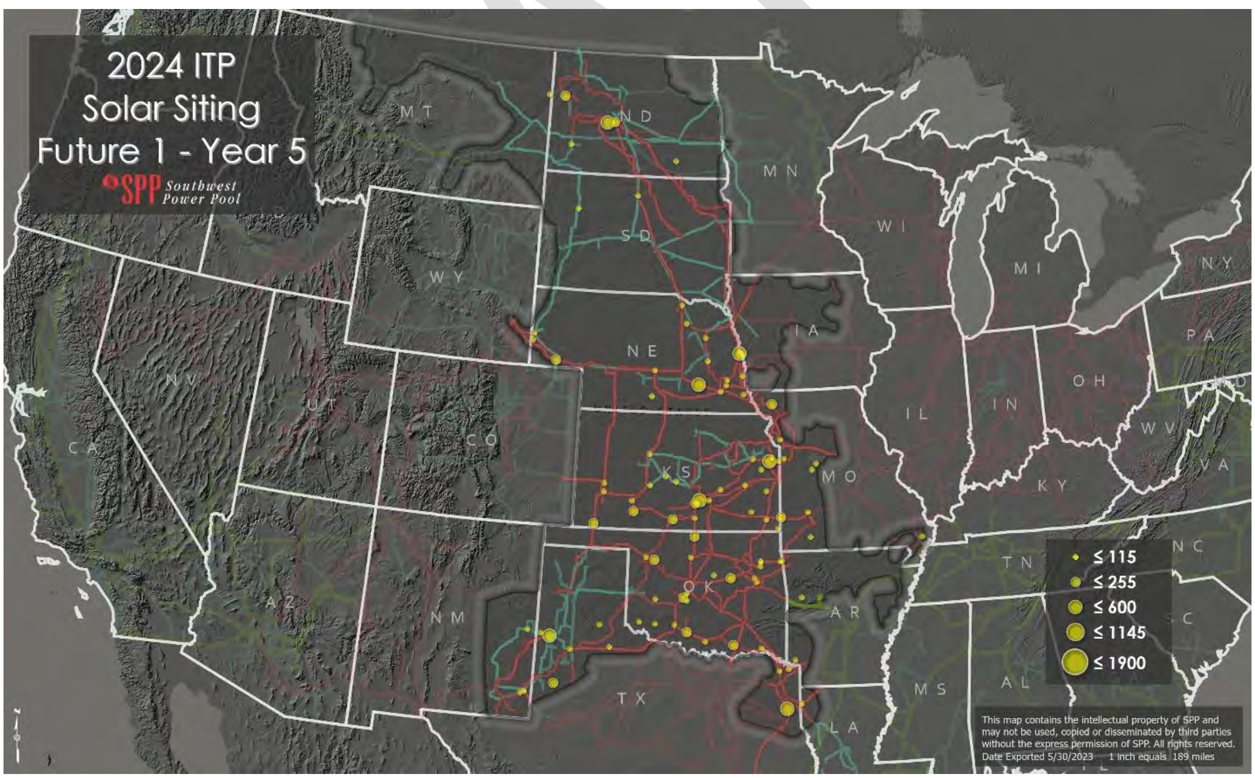

Figure 3.10: Future 1 Year 5 Solar Siting

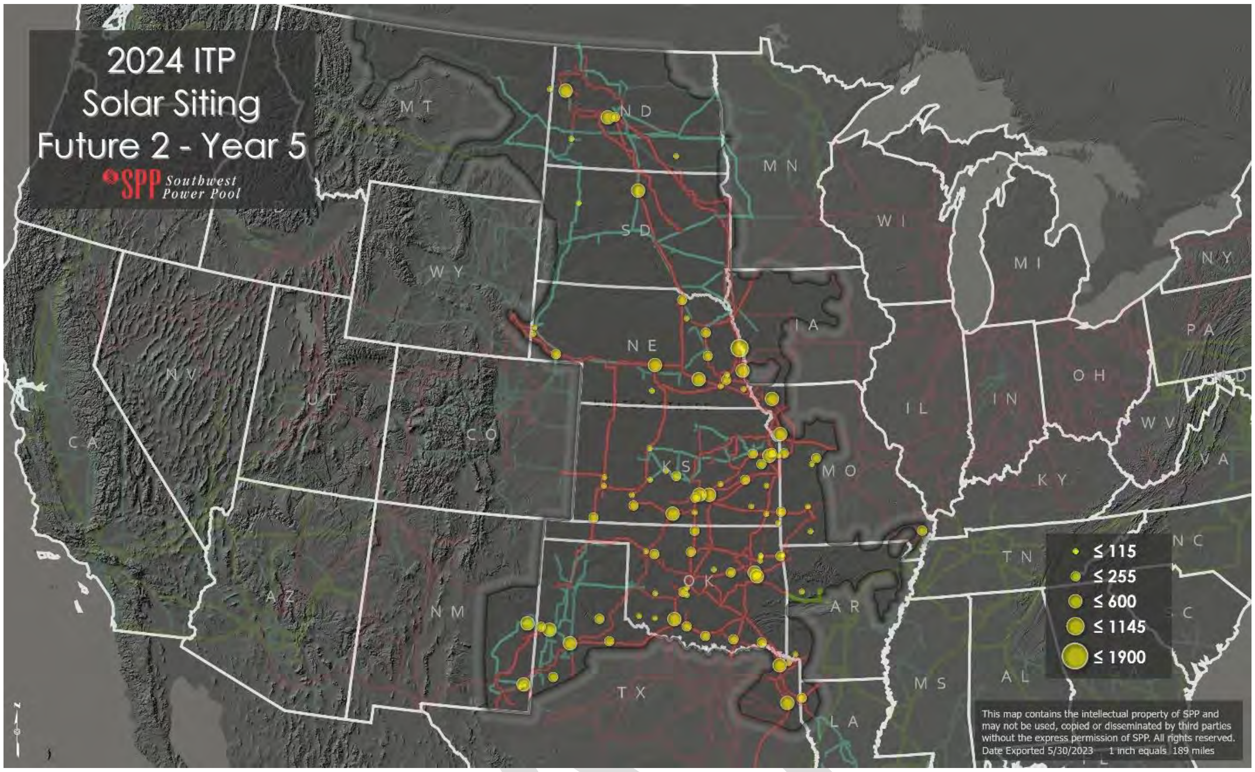

Figure 3.11: Future 2 Year 5 Solar Siting

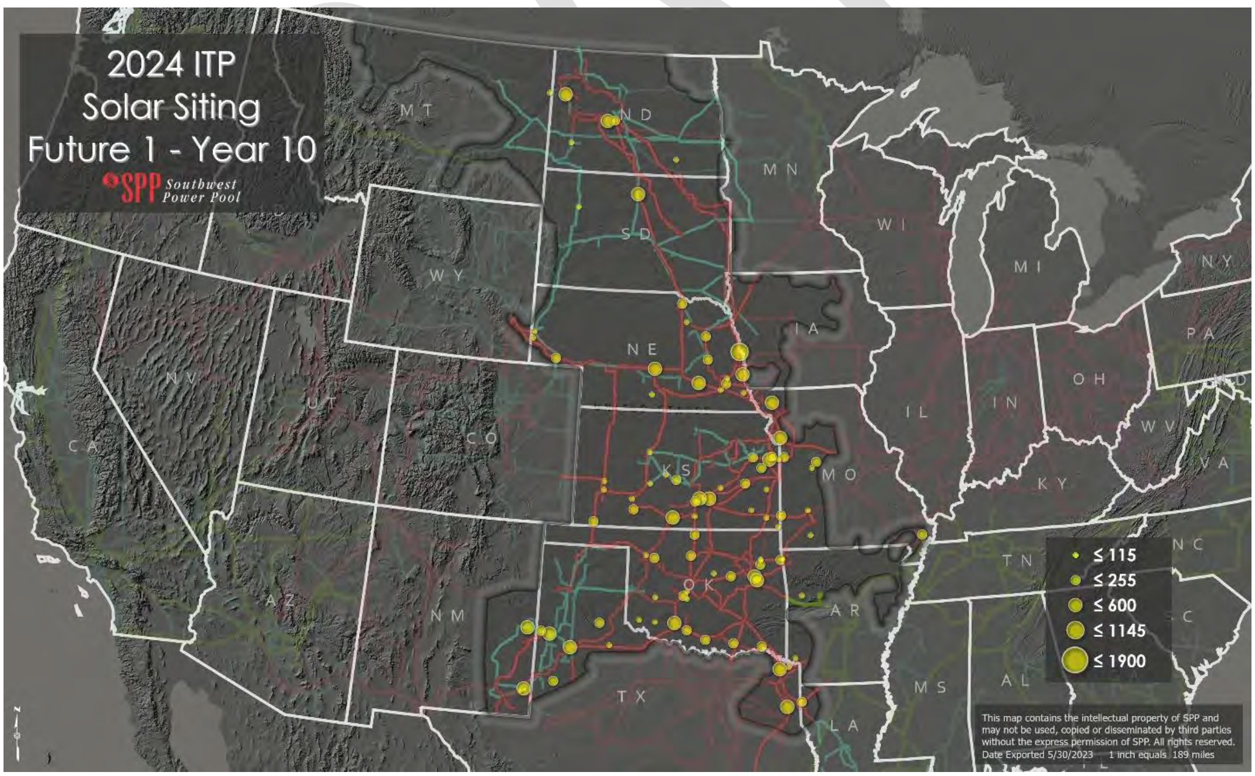

Figure 3.12: Future 1 Year 10 Solar Siting

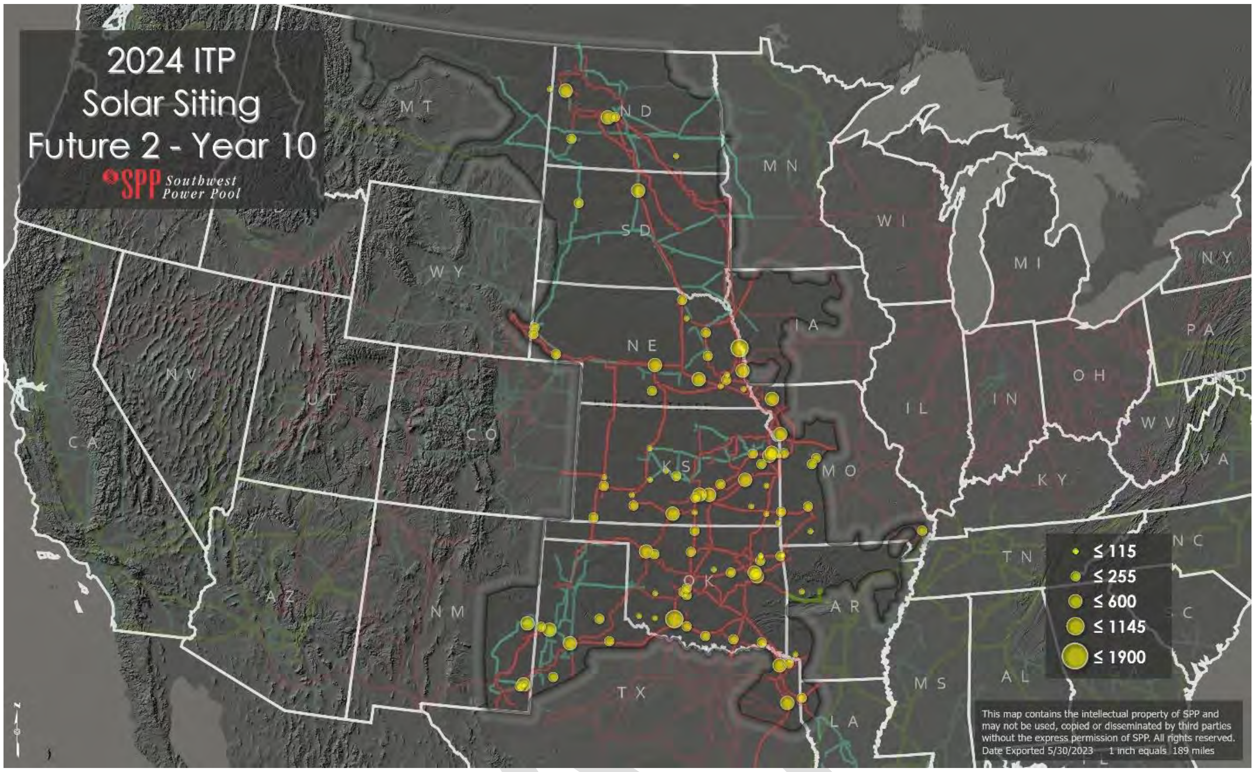

Figure 3.13: Future 2 Year 10 Solar Siting

3.2.2.3.2 WIND SITING

SPP selected wind sites from GI queue requests that required the lowest total interconnection cost[24] per megawatt of capacity requested, taking into consideration the following:

- Potentially directly assigned upgrade needed
- Unknown third-party system impacts
- Required generator outlet facilities (GOF)
- Generator Interconnection Agreement (GIA) suspension status

SPP also considered GI queue requests that did not have costs assigned with respect to their generator outlet capability, scope of related GOFs needed, and relation to recurring issues within the GI grouping.

Following implementation of this ranking criteria, stakeholders could request exceptions to these results, which SPP reviewed for potential inclusion in the siting plan. Figure 3.14 through Figure 3.17 show the selected siting and allocation of wind capacity across the SPP footprint in megawatts.

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[24] The total interconnection costs include the total costs assigned for all interconnection related upgrades and network upgrades.

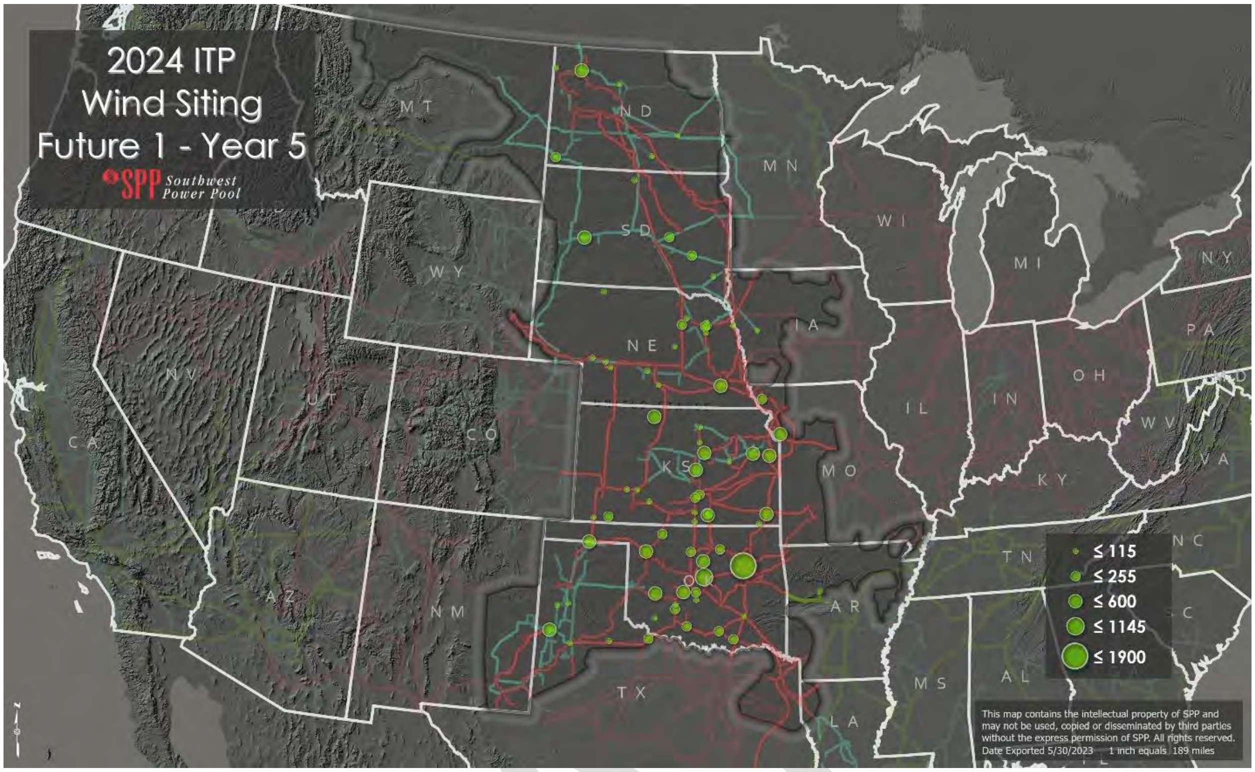

Figure 3.14: Future 1 Year 5 Wind Siting

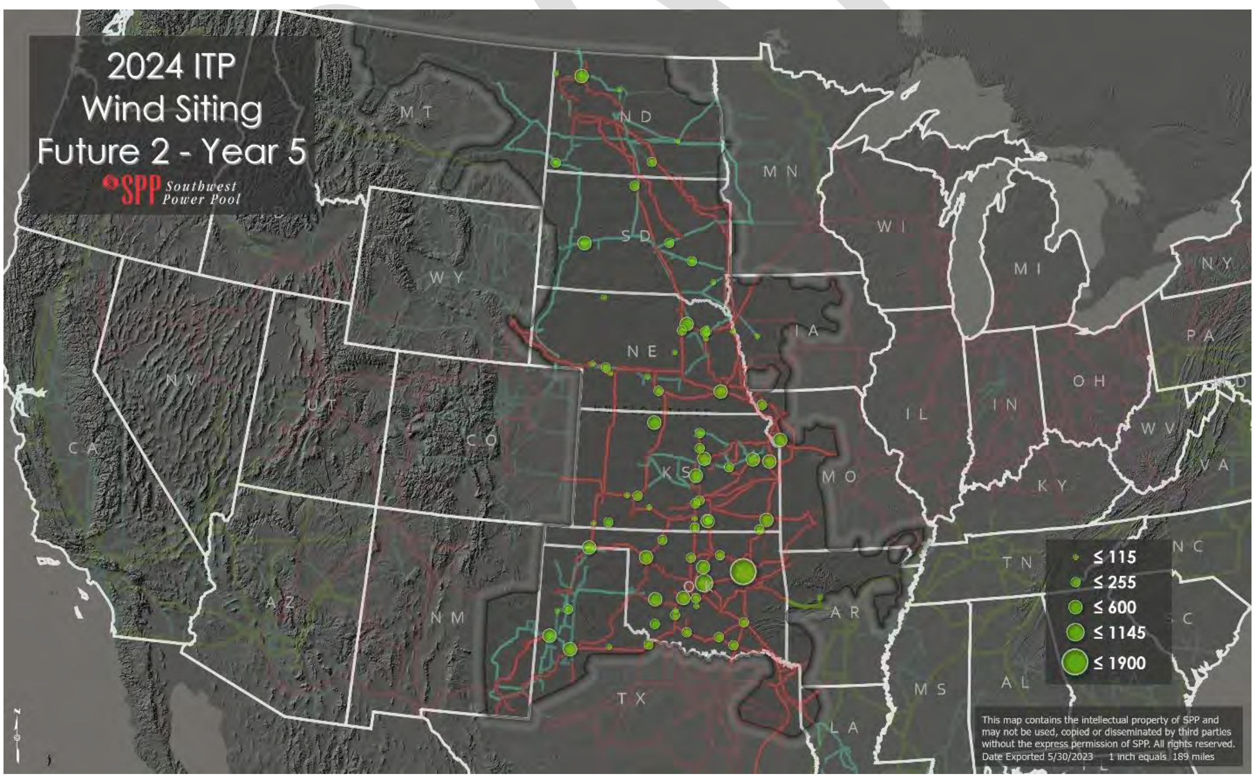

Figure 3.15: Future 2 Year 5 Wind Siting

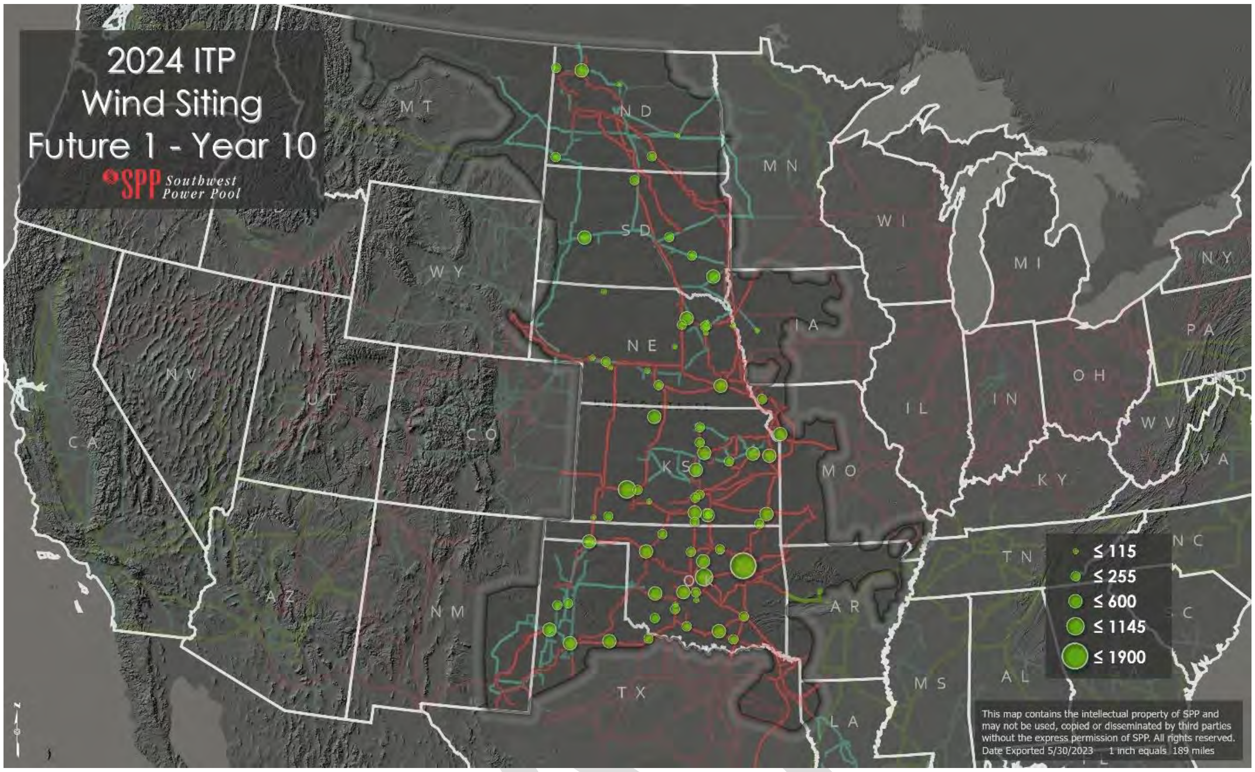

Figure 3.16: Future 1 Year 10 Wind Siting

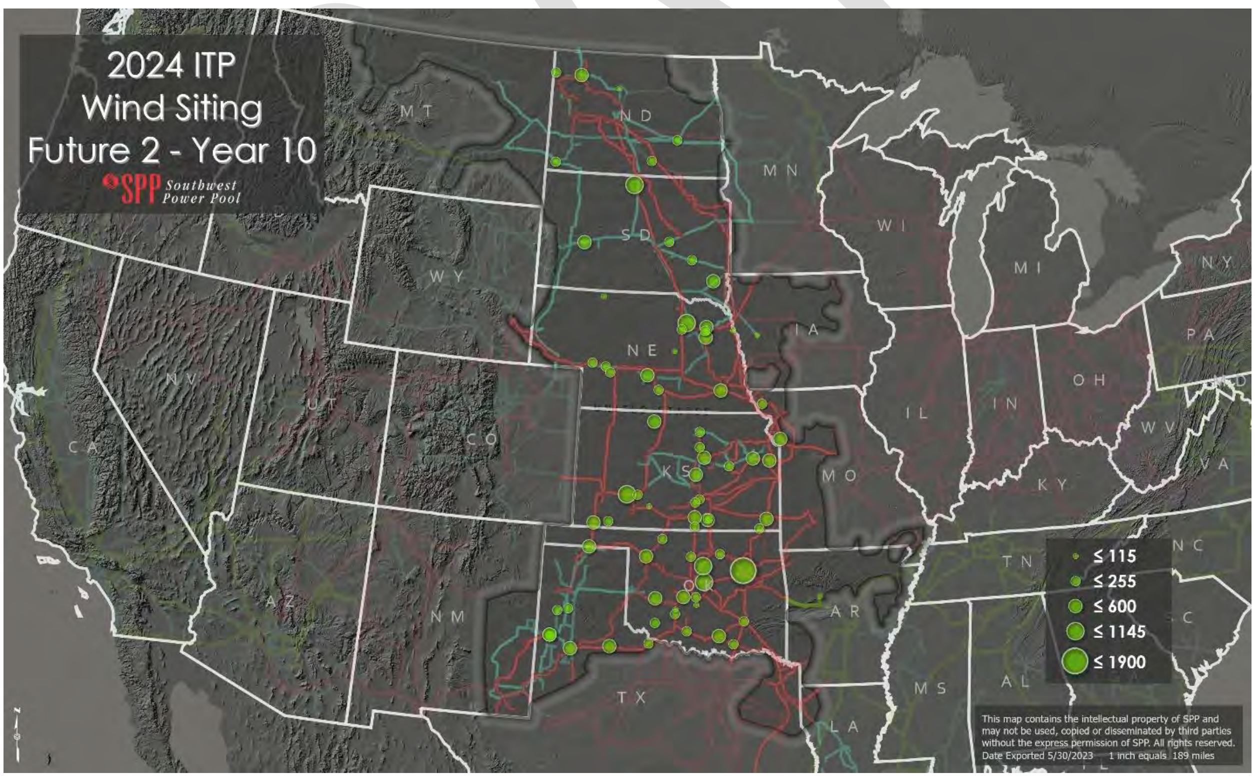

Figure 3.17: Future 2 Year 10 Wind Siting

3.2.2.3.3 BATTERY SITING

SPP selected battery sites based on the assumption that battery storage will largely be co-located with wind and solar resources considering transfer capability at available sites that were included in the solar and wind siting plans. SPP also based a percentage of the sites on battery storage GI queue requests, limiting those resources to two-thirds of the overall projected battery capacity due to the infancy of the technology. Half of projected battery capacity was associated with solar sites and half was associated with wind sites. SPP included the percentage of the capacity related to battery storage GI queue requests in those groups where applicable. For sites associated with battery requests, SPP capped the sited battery amounts at the queue request amounts or siting availability. For sites not associated with existing battery GI requests, SPP assigned battery amounts at wind and solar sites in increments of 20 megawatts (SPP utilized different increments where needed) and capped at siting availability. Following implementation of this ranking criteria, stakeholders could request exceptions to these results, which SPP reviewed for potential inclusion in the siting plan. Figure 3.18 through Figure 3.21 show the selected sites for battery generation across the SPP footprint.

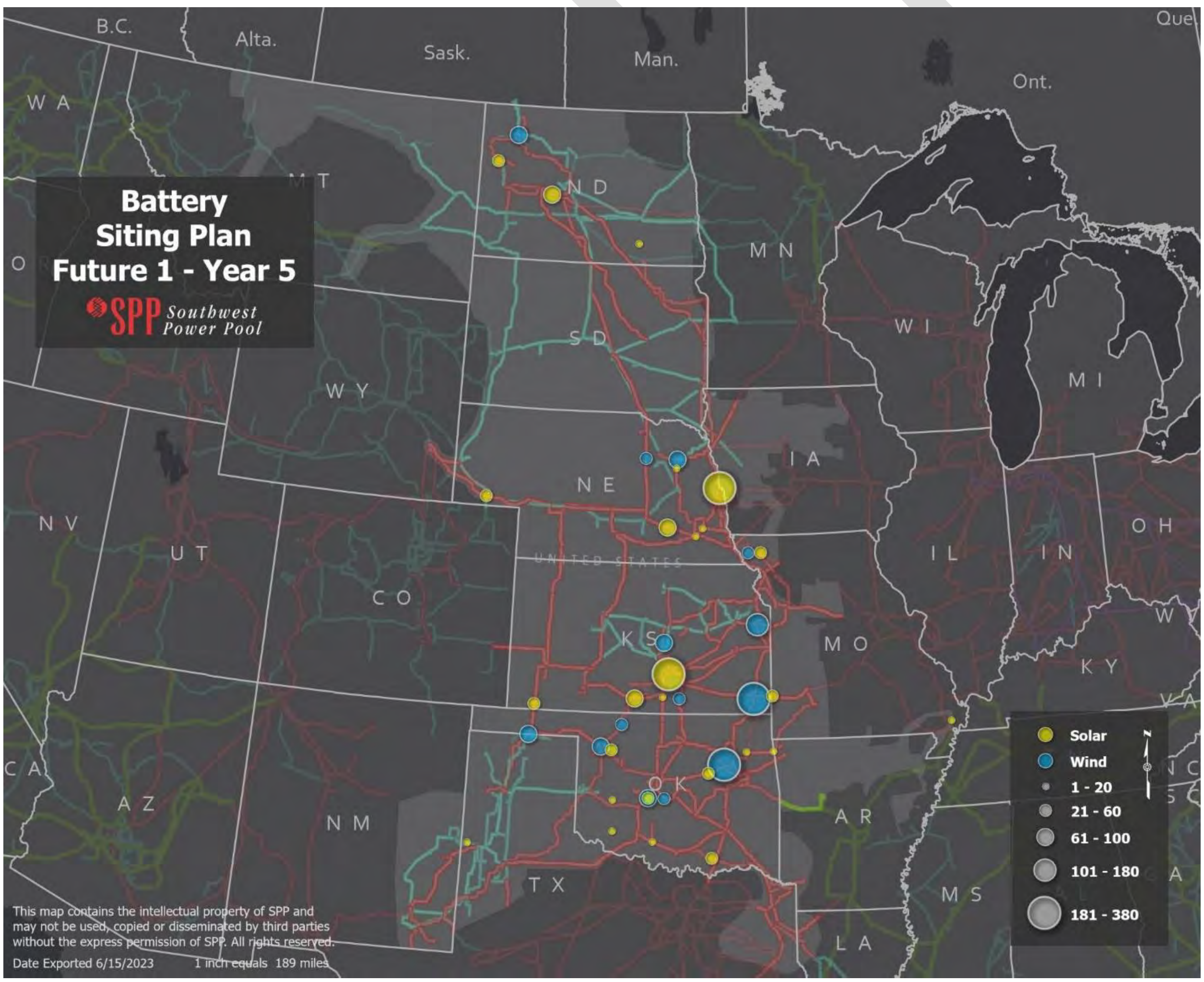

Figure 3.18: Future 1 Year 5 Battery Siting

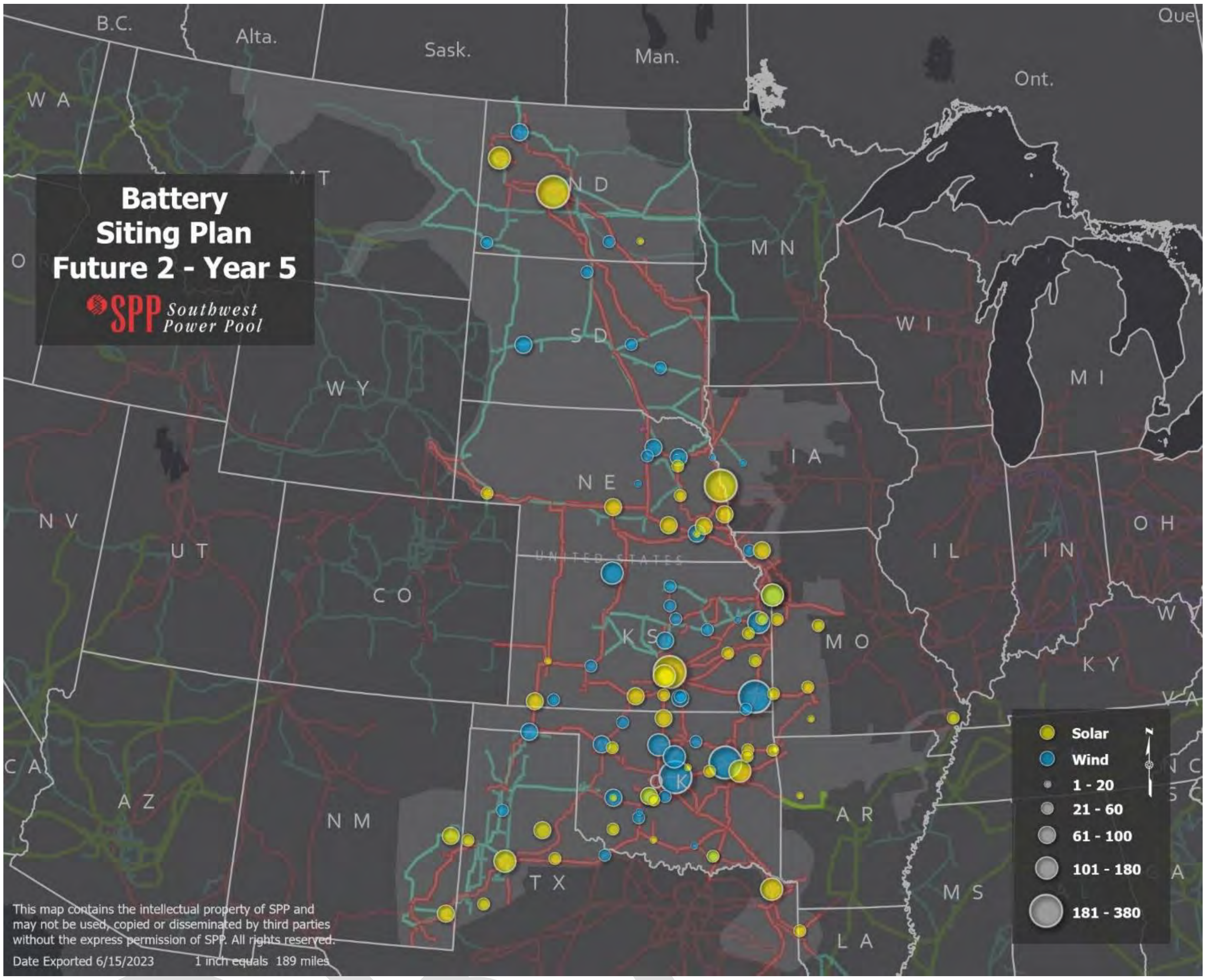

Figure 3.19: Future 2 Year 5 Battery Siting

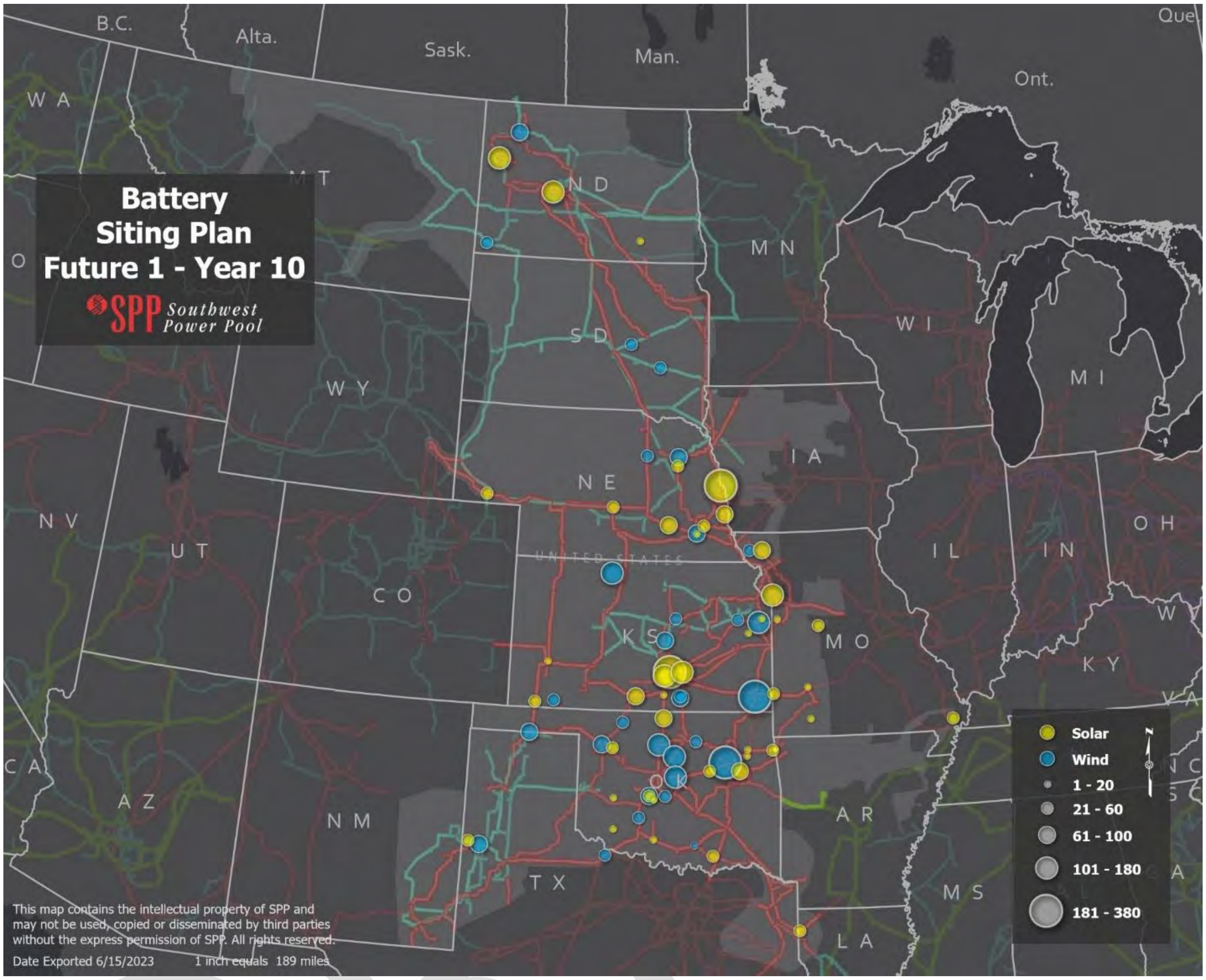

Figure 3.20: Future 1 Year 10 Battery Siting

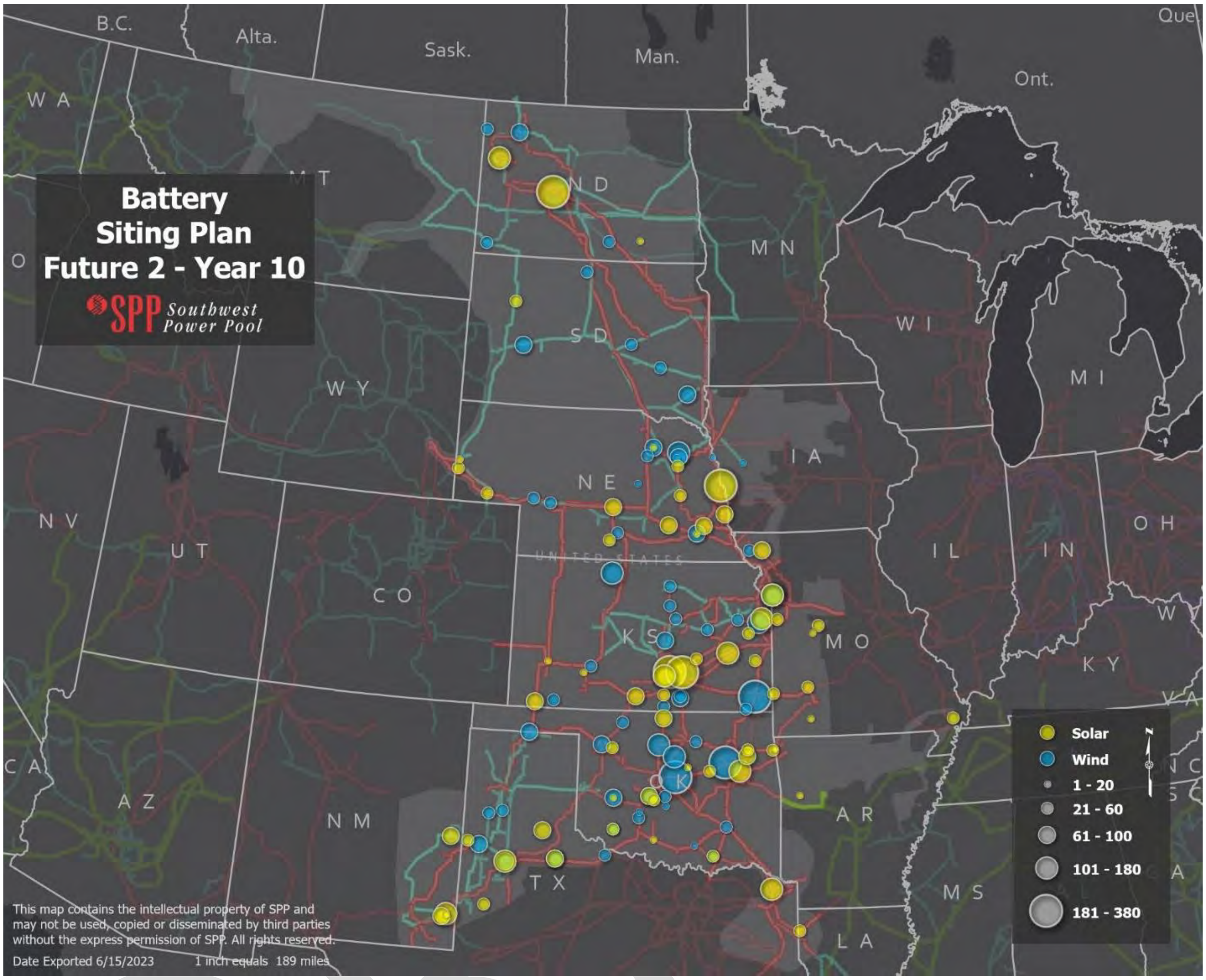

Figure 3.21: Future 2 Year 10 Battery Siting

3.2.2.4 *GENERATOR OUTLET FACILITIES*

Generator Outlet Facilities (GOFs) are facilities incorporated by SPP into the market economic models when necessary to ensure that prospective generation added from the siting plan does not create undue economic needs on the system. For sites with upgrades identified in a GI study, the associated upgrades were evaluated and were potentially recommended as a GOF. In other instances, the site-specific results of the transfer analysis were assessed to determine if a site was capable of reliably allowing a resource to dispatch to the SPP system (siting availability). The GOF upgrades for this study resulted from the siting availability checks and are shown in Table 3.4.

GEN #	Site Name	Upgrade Description	F1 Y5	F2 Y5	F1 Y10	F2 Y10	Source
GEN-2018-067	Judson-Tande 345 kV	Build a second 115 kV line from Mont to North Missouri Ridge (8.74 miles)			X	X	GI Queue
GEN-2018-067	Judson-Tande 345 kV	Build a second 115 kV line from Mont to Strandahl (11.97 miles)			X	X	GI Queue

GEN #	Site Name	Upgrade Description	F1 Y5	F2 Y5	F1 Y10	F2 Y10	Source
GEN-2020-016	Cromwell 138 kV	Build a second 138 kV line from Snyder to G20-016-Tap (14.61 miles)		X	X	X	GI Queue
GEN-2017-175	Vfodnes 230 kV	Build a second 230 kV line from VFodness to G17-175-TAP (29.8 miles)			X	X	GI Queue
GEN-2017-222	Denison 230 kV	Rebuild the Denison to Boyer 69 kV 2.88 mile line	X	X	X	X	GI Queue
GEN-2018-067	Judson-Tande 345 kV	Rebuild the existing North Missouri Ridge to Eastfork 115 kV line (4.7 miles)			X	X	GI Queue
GEN-2017-048	Neset 230 kV	Rebuild the existing Neset to Tioga 230kV 1 mile line to achieve a minimum summer/emergency rating of 615 MVA	X	X	X	X	GI Queue
GEN-2020-016	Cromwell 138 kV	Rebuild the Walters2 to Walters-2 69 kV mile 5.13 line to a minimum of 56 MVA		X	X	X	GI Queue
GEN-2020-016	Cromwell 138 kV	Replace Snyder 138-69 kV transformer to a minimum of 90 MVA		X	X	X	GI Queue
GEN-2017-119	Elm Creek 345 kV	Replace the existing 230/115 kV transformer at Concordia West		X	X	X	GI Queue
GEN-2017-144, 181, 182, 234	Holt 345kV, Moore 345 kV, North Loup-Spalding 115 kV	Replace the existing 345/115 kV transformer at Mark Moore	X	X	X	X	GI Queue
GEN-2016-119	Sooner-Spring Creek 345 kV	Upgrade terminal equipment for the Northwest to Spring Creek 345 kV line to achieve minimum summer/emergency rating of 1306 MVA	X	X	X	X	GI Queue
GEN-2016-119	Sooner-Spring Creek 345 kV	Upgrade terminal equipment for the G16-100-TAP to Spring Creek 345 kV line to achieve minimum summer/emergency rating of 1276 MVA	X	X	X	X	GI Queue
GEN-2017-048	Neset 230 kV	Upgrade terminal equipment at Tioga 230kV to achieve a minimum Summer/Emergency rating of 615 MVA	X	X	X	X	GI Queue
GEN-2016-030	Brown 138 kV	Rebuild the existing Brown-South Brown 138 kV line to achieve a minimum of 286 MVA	X	X	X	X	FCITC[25]

[25] First Contingency Incremental Transfer Capability (FCITC)

GEN #	Site Name	Upgrade Description	F1 Y5	F2 Y5	F1 Y10	F2 Y10	Source
GEN-2021-003	Fairview 115 kV	Rebuild the existing Fairview-Williston 115 kV line to achieve a minimum rating of 239 MVA				X	FCITC

Table 3.4: Generator Outlet Facilities

3.2.2.5 *EXTERNAL REGIONS*

When developing renewable resource plans, SPP did not directly consider renewable policy requirements for external regions. However, the MISO and Tennessee Valley Authority (TVA) renewable resource expansion and siting plans were based on the 2021 MISO Transmission Expansion Planning (MTEP21) continued fleet change (CFC) and accelerated fleet change (AFC) futures. AECI renewable resource expansion plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI.

SPP also incorporated conventional resource plans for external regions included in the market simulations. SPP surveyed each region for load and generation and assessed each region to determine the capacity shortfall. The MISO and TVA resource expansion and siting plans were based on the MTEP21 CFC and AFC futures, while AECI and Saskatchewan Power (SASK) resource expansion and siting plans were based on the SPP resource plan assumptions and feedback from the ESWG and AECI. Figure 3.22 and Figure 3.23 show the total capacity additions in 2028 and 2033 respectively by resource type within these external regions for Future 1 and Future 2.

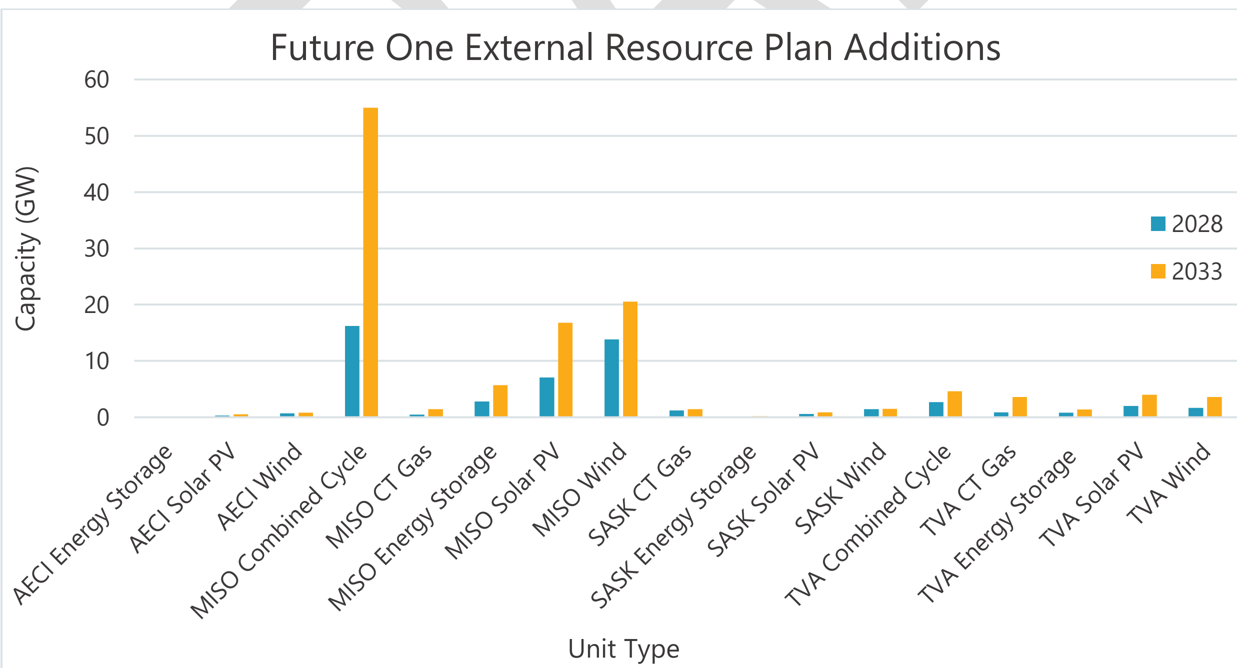

Figure 3.22: Future 1 Capacity Additions by Area and Resource Type

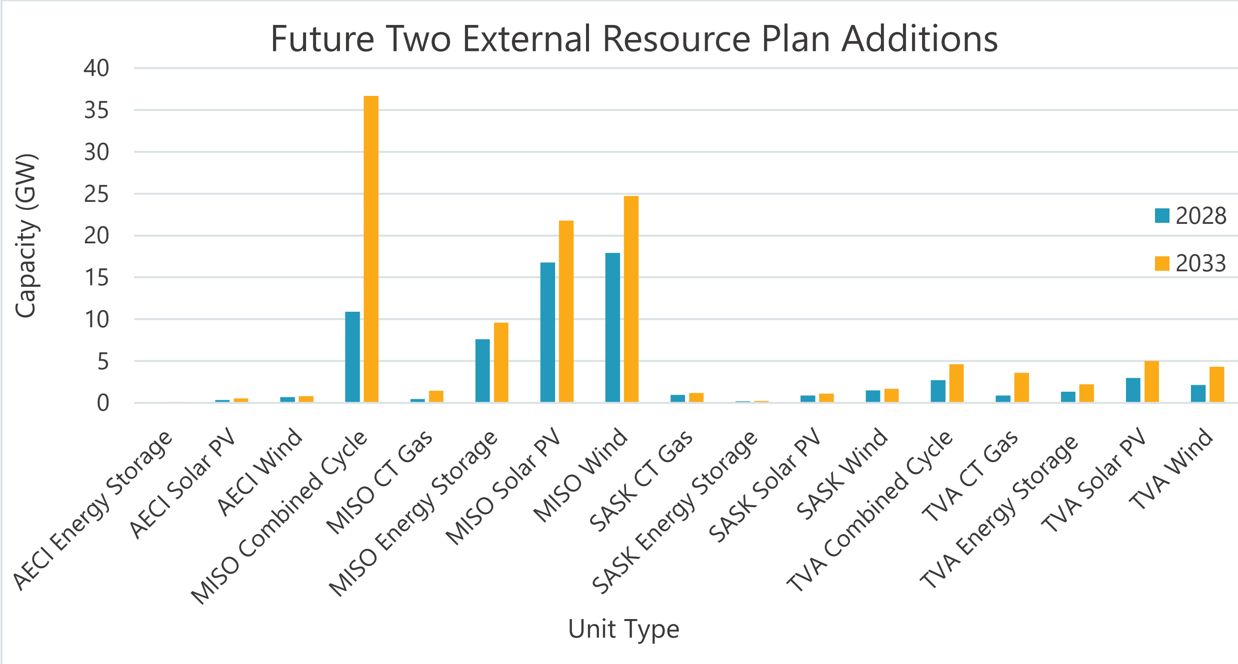

Figure 3.23: Future 2 Capacity Additions by Area and Resource Type

3.2.3 CONSTRAINT ASSESSMENT

SPP considers transmission constraints when reliably managing the flow of energy across physical bottlenecks on the transmission system in the least-costly manner. These study-specific constraints play a critical role in determining economic transmission needs, as the constraint assessment identifies future bottlenecks and fine-tunes the market economic models.

SPP conducted an assessment to develop the list of transmission constraints used in the security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) analysis for all futures and study years. SPP defined the initial list of constraints by leveraging the SPP permanent flowgate list,[26] which consists of NERC-defined flowgates that are impactful to modeled regions and recent temporary flowgates identified by SPP in real time. In the 2024 ITP, consistent with the 2023 ITP, SPP incorporated stakeholder feedback by widening the criteria used to evaluate contingencies for inclusion, reducing the minimum loading on 200 kV+ equipment from 25% down to 10%. SPP did this to evaluate the impact of contingencies involving high voltage (HV) equipment, even when that equipment experiences relatively low flows.

SPP used MTEP21 constraints to help evaluate and validate constraints identified within MISO and other neighboring areas. SPP also considered constraints identified in neighboring areas for inclusion as a part of the ITP study constraint list. New to the constraint assessment in the 2024 ITP cycle, was the inclusion of the most critical MPM thermal violations. The monitored and contingent elements of these MPM thermal needs underwent a reclassification process, allowing them to be incorporated into the

[26] Posted on OASIS: https://www.oasis.oati.com/SWPP/index.html

economic analysis of the 2024 ITP. The TWG reviewed and approved the identified constraints as potentially limiting the incremental transfer of power throughout the transmission system, both under system intact and contingency situations.

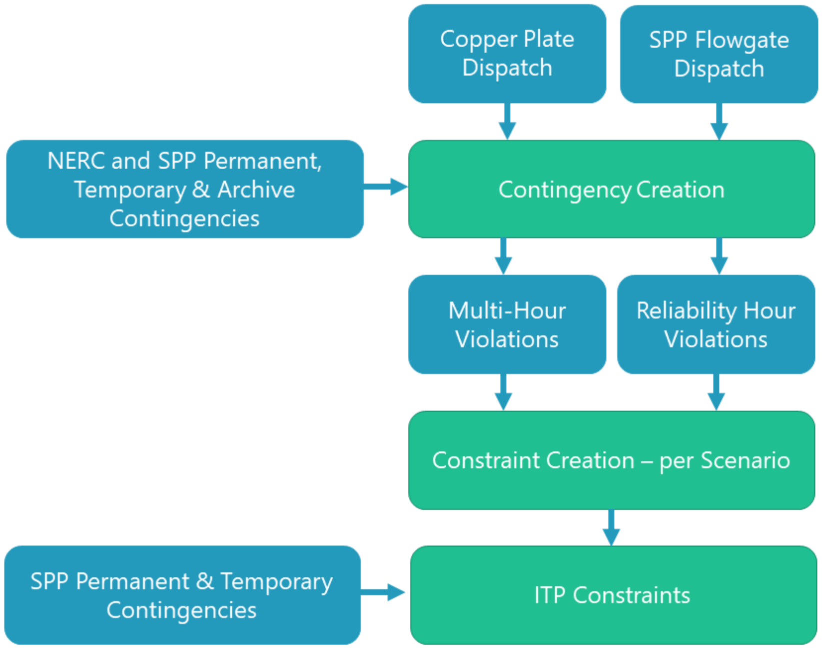

Figure 3.24: High level Constraint Assessment Process[27]

3.3 MARKET POWERFLOW MODEL

Due to the MOPC approved waiver on July 16, 2024, the Market Powerflow Model set was carved out of the 2024 ITP Assessment.

3.4 EXTREME WINTER MODEL DEVELOPMENT

SPP built two distinct sets of powerflow models to mimic the effects of extreme winter weather on the SPP system. The first winter weather model set is based upon winter storm Elliott, while the second model set is based upon a combination of real-time data from Winter Storm Uri and expected future load on the system. describes at a high level the recommended model development for the evaluation of extreme winter weather. The following sections provide more details on the development of each model set.

[27] The Constraint Assessment methodology can be found in the ITP Manual version 2.16

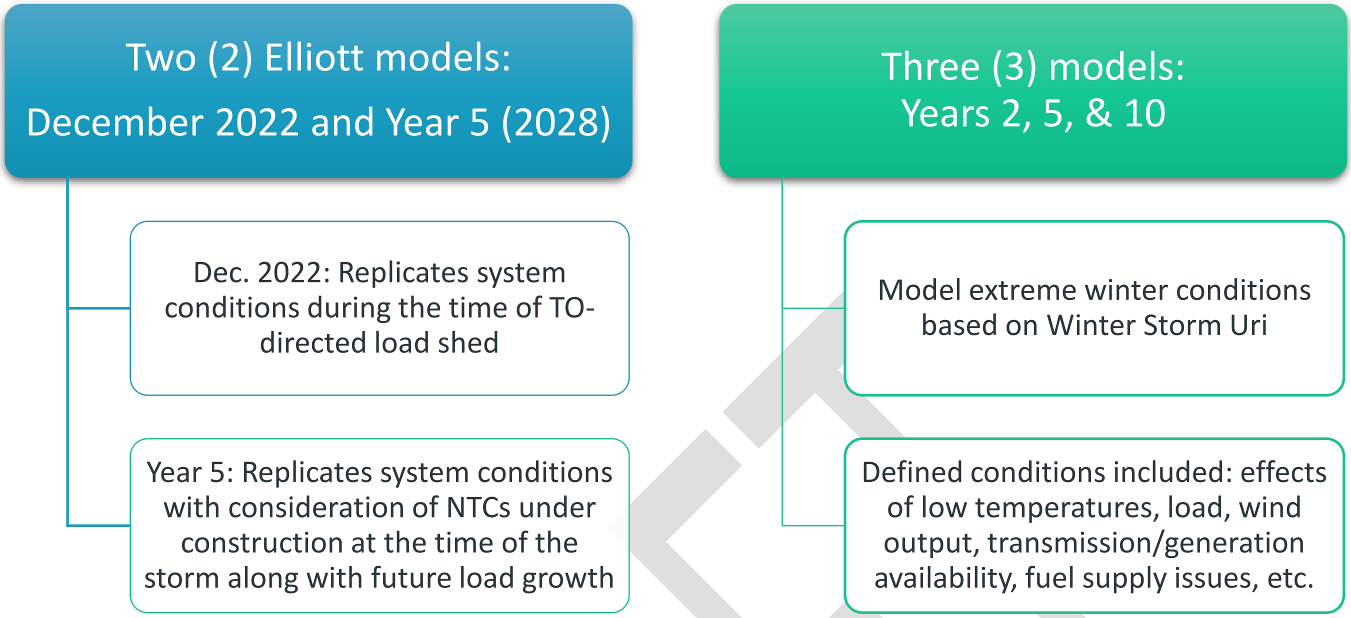

Figure 3.25: Extreme Weather Recommended Model Development

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3.4.1 WINTER STORM ELLIOTT MODELS

Staff and the WWST determined that the optimal way to study the impacts of Winter Storm Elliott was to create a model developed from real-time Energy Management System (EMS) data. SPP engineering staff received three different cases from the SPP operations staff representing different operating points during the winter event, including the point in time just after the TO-directed load shed event occurred. Staff and stakeholders agreed this was the best model to evaluate the impacts. These EMS cases included specific details such as:

- Status and dispatch amounts of generators
- Transmission facility status
- Bus level load data
- System voltages

Because the model was built using EMS data, significant differences were found when comparing the basic model data such as bus numbers and names to standard ITP cases. Where possible, SPP modeling staff updated data to make it easier on stakeholders to utilize the models by updating bus names and bus numbers.

As identified in SPP's response to the 2022 winter storm, two key transmission lines terminating near the Kansas-Missouri border were either out-of-service or under construction.[28] These lines start in

[28] The Neosho-Riverton 161kV line was out-of-service at the time being rebuilt, while the new Wolf Creek-Blackberry 345 kV line approved from the 2019 ITP was under construction.

Kansas and terminate near the Kansas-Missouri border. The report also noted that these two lines would have provided support to the area of low voltage.

There are still questions about the ability of those transmission lines to support the south-central Missouri area as loads continue to increase in the SPP footprint. To evaluate this, staff and stakeholders recommended the development of a future 'Winter Storm Elliott' model.

To make the development of this model simpler, staff and the WWST recommended using the 2024 ITP 2028 winter (year five) base reliability model as a starting point. To account for Elliott-based system conditions staff made the following changes:

- Redistributed the regional load to match the zonal load-ratio-share from the EMS model
- Matched the generation output from the EMS model into the year five Elliott model
- Increased generation outside the target area to account for the increase load in the planning models
- Updated status (i.e. in-service or out-of-service) of all transmission elements such as transmission lines, transformers, capacitors, and generators to match their status in the EMS data
- Utilized additional software to ensure that the dispatch was security-constrained to ensure it was more reflective of a market dispatch.

After completing these high-level revisions, staff was unable to get the model to solve without the inclusion of a fake Static Var Compensator (SVC) within the target area. This SVC was ultimately located at the Stateline bus just north of Joplin, Missouri. This indicated that even with the additional transmission lines, the target area was not able to remain within the planning criteria bus voltage requirement of 0.90 per unit (p.u.) to 1.05 p.u.

3.4.2 WINTER STORM URI-BASED MODELS

During discussions to incorporate extreme winter weather analysis into the 2024 ITP, the TWG recommended a second set of models be developed. This recommendation ensured the rest of the region was evaluated given that the Elliott-based models were developed with the evaluation of the target area as the major focus.

The WWST considered 3 different approaches for building the second set of extreme winter weather models. Initially, consideration was given to include data from both winter storms to create an approach. After reviewing the differences between the two winter storms, SPP determined that utilizing real-time data from Winter Storm Uri would be the best way to evaluate the impacts of extreme winter weather to the footprint. Additionally, feedback was given to staff that a beneficial analysis utilizing Winter Storm Uri data would be more widely supported if the developed models captured the regional flows observed during the winter event.

The preferred option from those discussions was to build a model that assumed high level variables based upon data from Winter Storm Uri. The high-level variables included:

- Timeframe
- System load
- Generation availability/unavailability
- Generation additions
- Import/Export amounts
- Generator dispatch

3.4.2.1 *TIMEFRAME*

Staff polled stakeholders requesting feedback to determine the critical time period from Winter Storm Uri for data collection. During the winter event, SPP declared several Emergency Energy Alerts (EEA)[29], including EEA Level 1, EEA Level 2, and EEA Level 3's. The following table outlines the time periods SPP declared the various EEA levels.

EMERGENCY ENERGY ALERT	TIME
All EEA Levels	~90 hours
EEA Level 1	~37 hours
EEA Level 2	~40 hours
EEA Level 3	~10 hours

Table 3.5: Emergency Energy Alert Durations

Because EEA Level 3 indicates that RTO-directed load shed is imminent or in progress, stakeholder agreed that utilizing data specific to these time periods was most useful. Determining this timeframe gave each of the previously listed variables a good starting point for real-time data considerations.

3.4.2.2 *SYSTEM LOAD*

To support the creation of a load profile, the WWST compared the 2023 ITP and 2024 ITP base reliability load forecasts to the two system peaks from winter storms Uri and Elliott. SPP recorded a new winter peak during Winter Storm Uri, but that value could have been even higher when considering the 2,700+ megawatts of load shed to maintain system stability. The two peak storm load values compared favorably to both of the ITP load forecast year two loads. This correlation led to a decision to utilize the 2024 ITP base reliability winter load forecasts as the regional load value. Similar to the Winter Storm Elliott models, the decision was made to redistribute the zonal loads to match the EMS load ratio share. This decision supported the concept of capturing the regional flows in the Uri-based models. Figure 3.26 shows the comparison between the operational peak observed during each winter storm (including the RTO-directed load shed) and the 2023 and 2024 ITP winter model load forecasts.

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[29] Information about Emergency Energy Alerts can be found on page 17 of SPP's Response to the December 2022 Winter Storm

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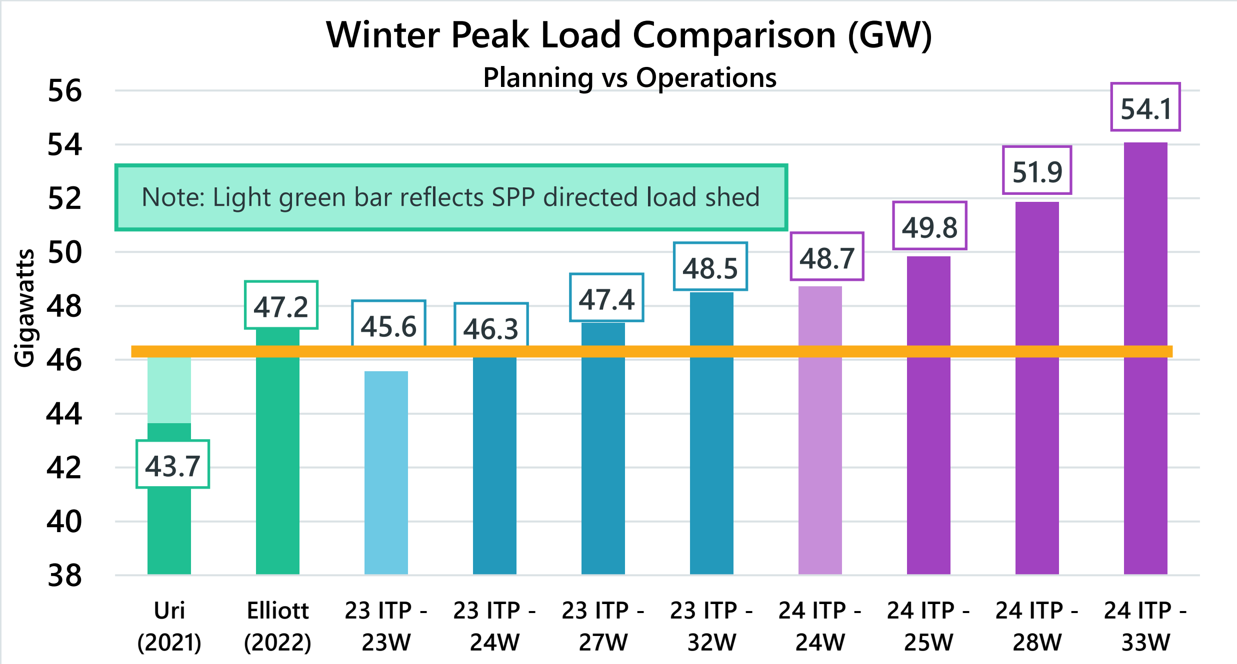

Figure 3.26: Winter Peak Load Comparison (GW)

3.4.2.3 *GENERATION AVAILABILITY/UNAVAILABILITY AND DISPATCH PROCESS*

One of the biggest impacts from Winter Storm Uri was the reduction in available generation capacity on the system. Cold weather effects such as below freezing temperatures, sustained high natural gas usage by homeowners and generators alike, and frozen coal piles contributed to significant reductions in the megawatt amount of generation available to serve load. Continuing forward with the direction to utilize data from the ten EEA Level 3 hours, generation availability was also considered.

SPP utilized Control Room Operations Window (CROW) data from the ten EEA Level 3 hours to identify the capacity reductions or outages observed in real-time during the winter event. CROW data includes relevant data for Operators to evaluate the reliability of the system. Important data such as the resource name, beginning and end of the capacity reduction/outage, a cause code identifying the reason for the capacity reduction or outage, and the MW value of capacity reduced. Summarizing this data for the ten hours identifies the total capacity unavailable. To implement these capacity reductions in a reasonable manner, staff mapped existing generators from the 2024 ITP generator review to the real-time crow capacity reductions or outages.

A comprehensive review of SPP's response to the February 2021 Winter Storm identified that the effect of the winter event was different for each fuel type. Additionally, the physical location of each resource also influenced the capacity reductions. For example, resources located in the northern part of SPP's footprint were built to withstand the cold temperatures, whereas limited gas pipelines into the parts of west Kansas or southern Missouri affected the ability to get the necessary natural gas needed to fuel a generator. With this information, staff and the WWST recommended to the TWG and ESWG that capacity reductions data should be specified by fuel type and state and applied on a percentage basis. Differentiating the capacity reductions in this manner continued to support the concept of capturing expected system flows from extreme winter weather. For example, resources in the southern portion of the SPP footprint saw more capacity reductions than the northern resources. Table 3.6 identifies the approved capacity reductions based on the EEA Level 3 hours from the larger load shed event that occurred during Winter Storm Uri. Based on the data, resources north of Kansas had similar capacity reduction percentage values and were grouped together to simplify the model build.

Area	Nuclear	Hydro	Natural Gas	Coal	Wind	Other
North	0%	0%	22.8%	4.7%	3.8%	23.9%
Kansas	0%	0%	42.7%	1.5%	27.1%	6.5%
Missouri	0%	0%	40.8%	1.8%	18.9%	48.8%
Oklahoma	0%	3.1%	58.7%	18.9%	42.9%	5.6%
Arkansas	0%	0%	35.8%	42.2%	0%	0%
Texas	0%	0%	46.4%	23.2%	21.1%	0%
Louisiana	0%	0%	23.5%	0%	0%	0%
New Mexico	0%	0%	40.3%	0%	18.7%	0%

Table 3.6: Approved Capacity Reductions

3.4.2.4 *GENERATION ADDITIONS*

Considering the previously mentioned large load growth in the 2024 ITP models and the capacity reduction data, it became clear that the Uri-based winter weather models would need additional generation added to ensure the model could serve the necessary load. To address this, SPP multiple options such as limiting capacity reductions, removing recently approved load addition requests, or maxing out imports from SPP neighbors.

The preferred approach was to add the wind and solar resources from 2024 ITP Future 2 to the model as well as reach out to individual TO's with conventional resources included in the SPP Generator Interconnection Queue. The Future 2 renewable resources were based upon the approved Siting plans for 2024 ITP year five and year 10. The conventional resources were included in the year 10 Uri-based extreme winter model if the TO maintained a high level of confidence the generator would receive a GIA and be placed in commercial operation. These generator additions were extremely valuable in allowing the Uri-based model to be solvable with the capacity reductions. The recommended capacity reductions in the previous section were also applied to the recommended generator additions. Figure 3.27 shows the amount of wind additions added to the Uri-based models for year five and year 10.

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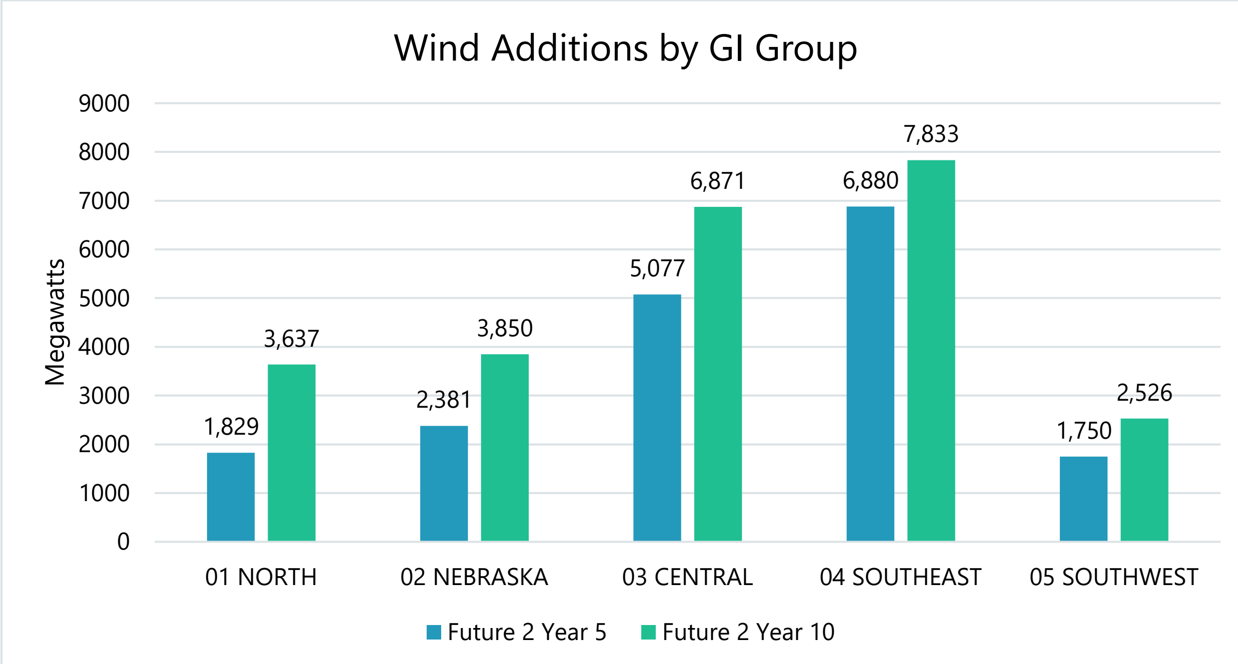

Figure 3.27: 2024 ITP Wind Additions by GI Group

3.4.2.5 *IMPORTS/EXPORTS*

One of the major impacts of Winter Storm Uri was the significant capacity reductions on the SPP generation fleet causing SPP to rely on its neighbors to import additional energy. For much of the event SPP imported from its eastern neighbors. When the availability of that energy was interrupted, SPP was unable to serve load. For this reason, it made sense to consider some assumed imports in the Uri-based model. EEA level 3 data revealed an average of ~3,800 megawatts of imports into SPP from MISO. The TWG/ESWG approved an approach to use this amount as an initial value with the ability to adjust imports as needed to ensure the models remained solvable.

3.4.2.6 *DISPATCH*

The initial dispatch of these Uri-based models was based upon an assumed market unit commitment to consider the impact of the Integrated Marketplace. Lower cost fuel types including wind, hydro, and coal were dispatched to their full capabilities. Natural Gas resources were turned on last and at less than full output to simulate the high natural gas costs observed during the winter event. Once this initial dispatch was solved, a powerflow software was used to identify and mitigate any lines that were overloaded with the initial dispatch. This resulted in curtailment of lower cost resources and an increase in natural gas generation to mimic the security-constrained dispatch of the Integrated Marketplace.

3.5 BENCHMARKING

3.5.1 POWERFLOW MODEL

SPP staff performed two benchmarks related to the 2024 ITP Base Reliability powerflow models. The first benchmark was a load and generation value comparison between the 2023 ITP and 2024 ITP Base

Reliability powerflow models. The second benchmark was a load and generation value comparison between the 2024 ITP Base Reliability powerflow models and real-time operational data. SPP staff conducted model comparisons to verify the accuracy of the powerflow model data, including:

- Comparison of the summer and winter peak base reliability model load totals (2023 ITP versus 2024 ITP), as shown in Figure 3.28 and Figure 3.29.
- Comparison of the summer and winter peak base reliability model generation dispatch totals for years two, five and 10 (2023 ITP versus 2024 ITP), as shown in Figure 3.30 and Figure 3.31.
- Additionally, the year 10 summer and winter peak generator retirements in the 2024 ITP Base Reliability powerflow models are shown in Figure 3.32.

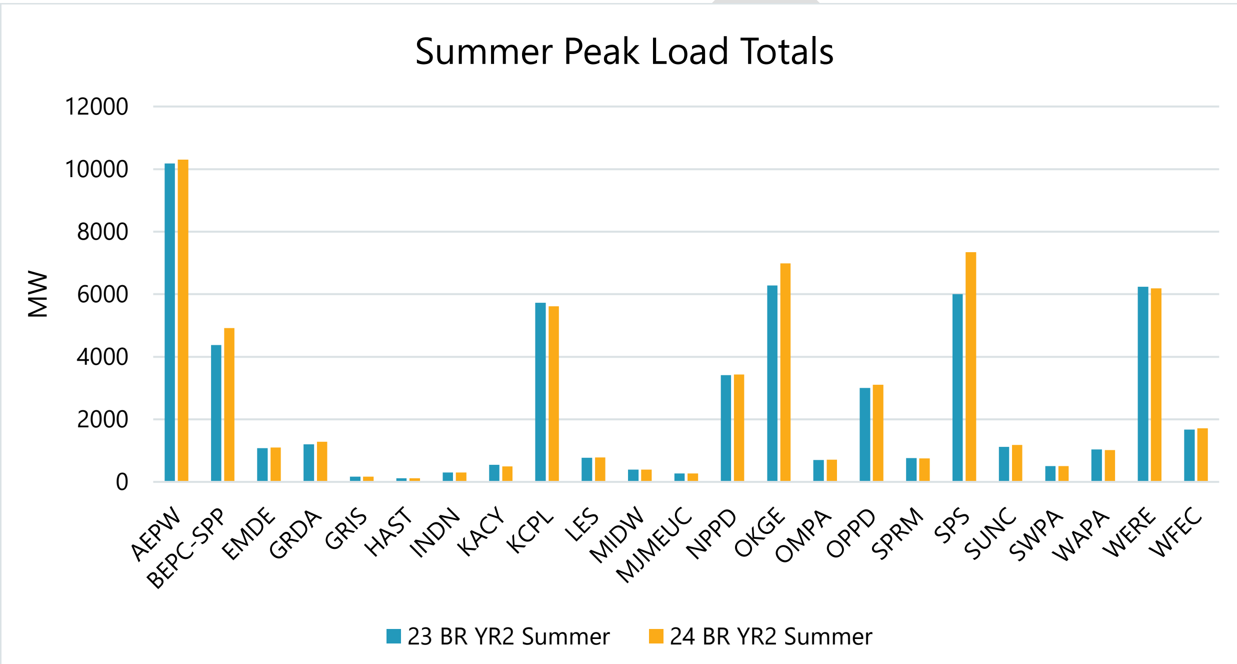

Figure 3.28: Summer Peak Year-Two Load Totals Comparison

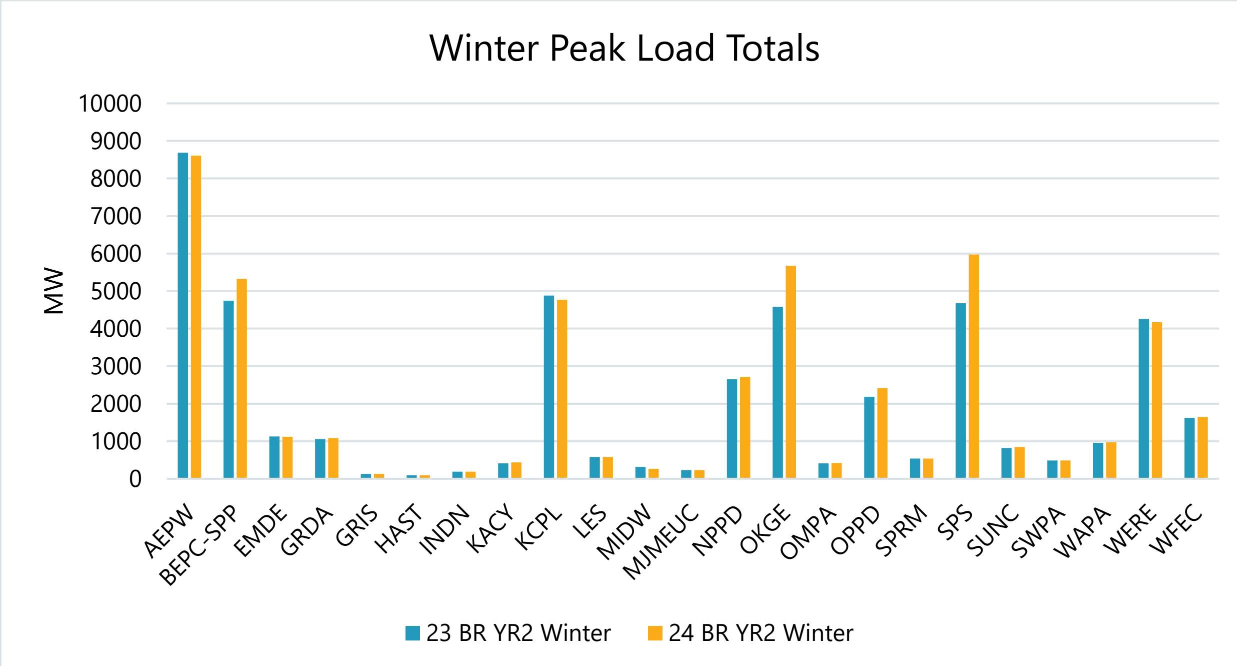

Figure 3.29: Winter Peak Year-Two Load Totals Comparison

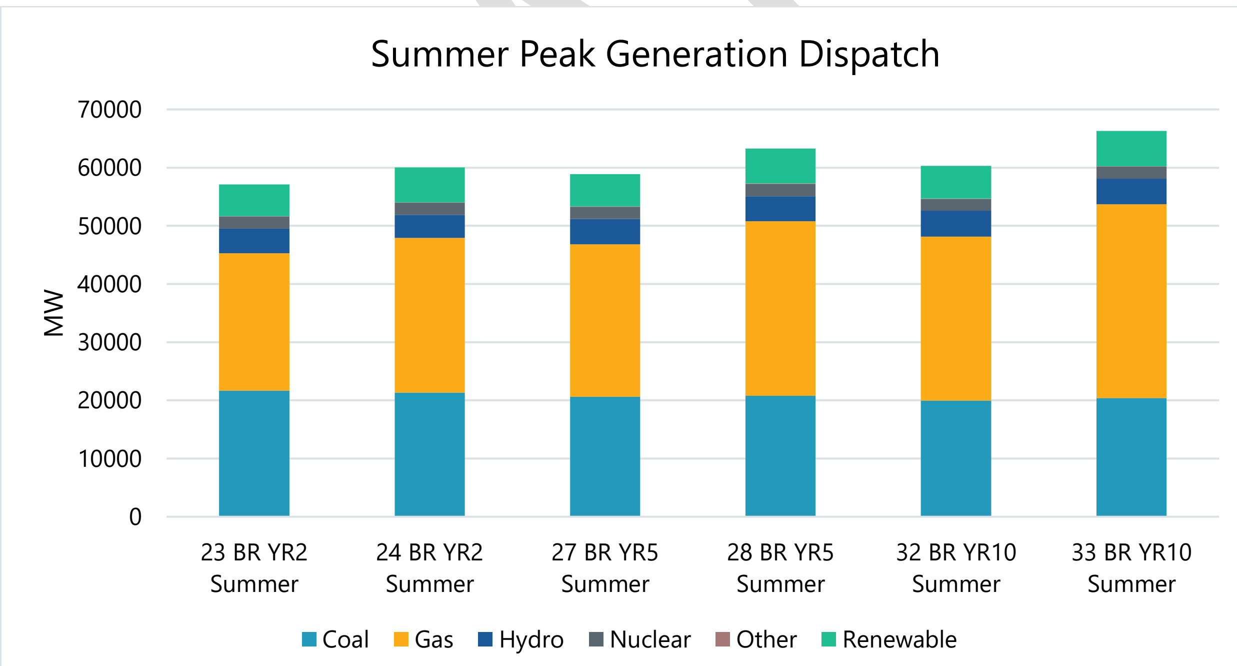

Figure 3.30: Summer Peak (MW) Years two, five, and 10 Generation Dispatch Comparison

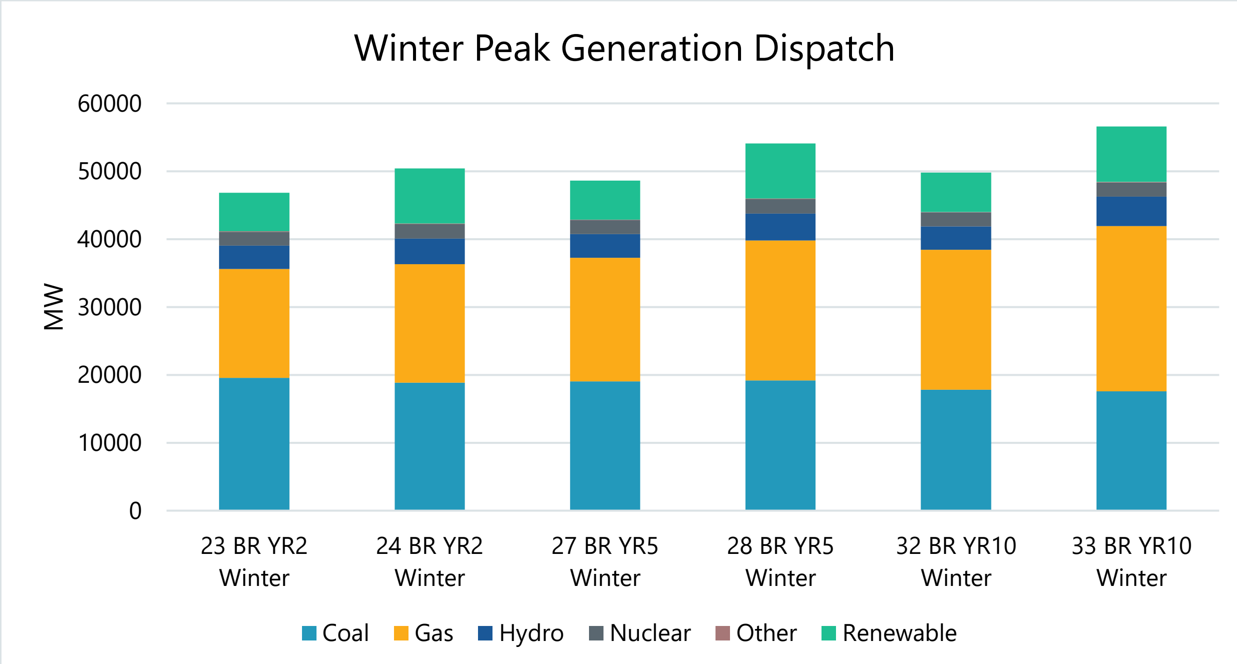

Figure 3.31: Winter Peak (MW) Years two, five, and 10 Generation Dispatch Comparison

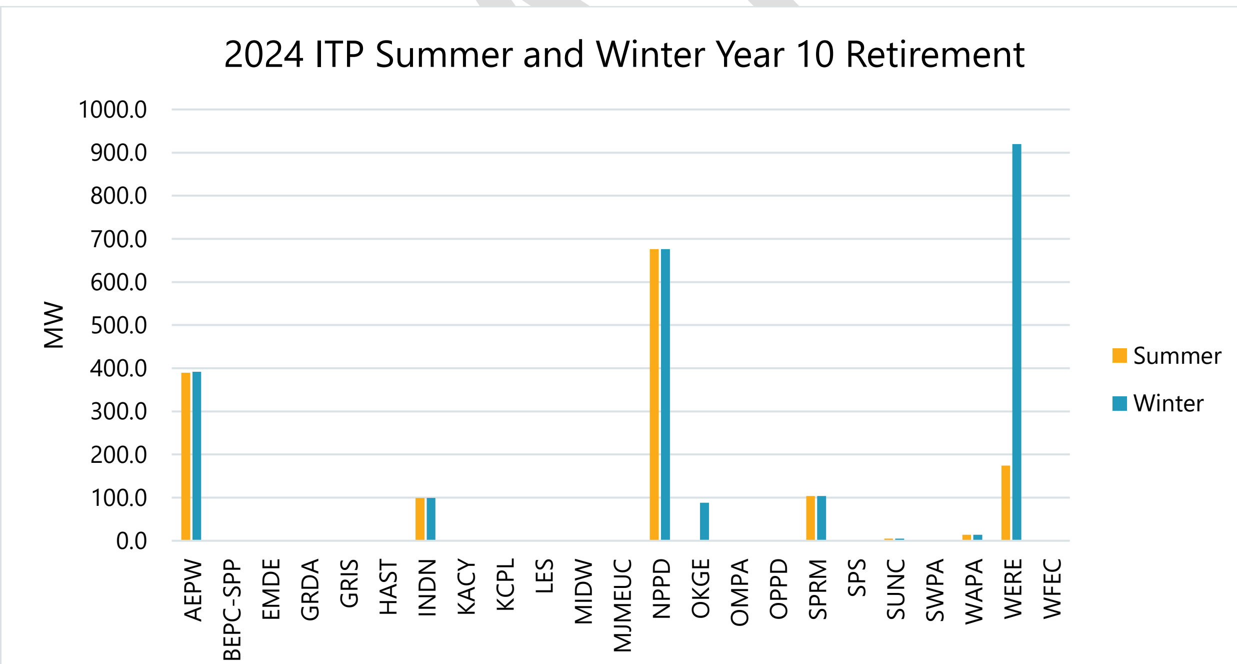

Figure 3.32: 2024 ITP Summer and Winter Year 10 Retirement

Operational model benchmarking for this assessment compared the 2023 summer and winter peak Base Reliability powerflow models against the real-time non-coincident operational data for the 2023-2024 winter and 2024 summer timeframe. Model comparisons were conducted to verify the accuracy of the powerflow model data, including:

- Comparison of the 2024 summer and winter load totals (base reliability model versus real-time non-coincident operational data), as shown in Figure 3.33 and Figure 3.34

- Comparison of the 2024 summer and winter generation dispatch totals (base reliability model vs real-time coincident operational data), as shown in Figure 3.35.

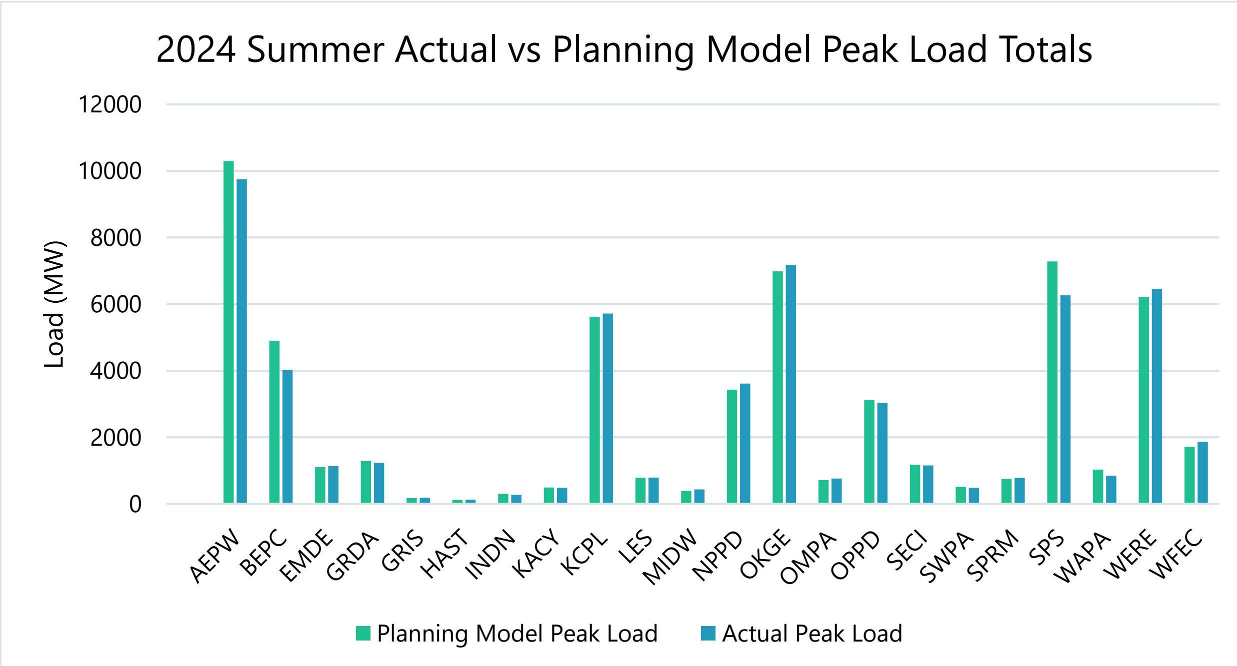

Figure 3.33: 2024 Summer Actual versus Planning Model Peak Load Totals

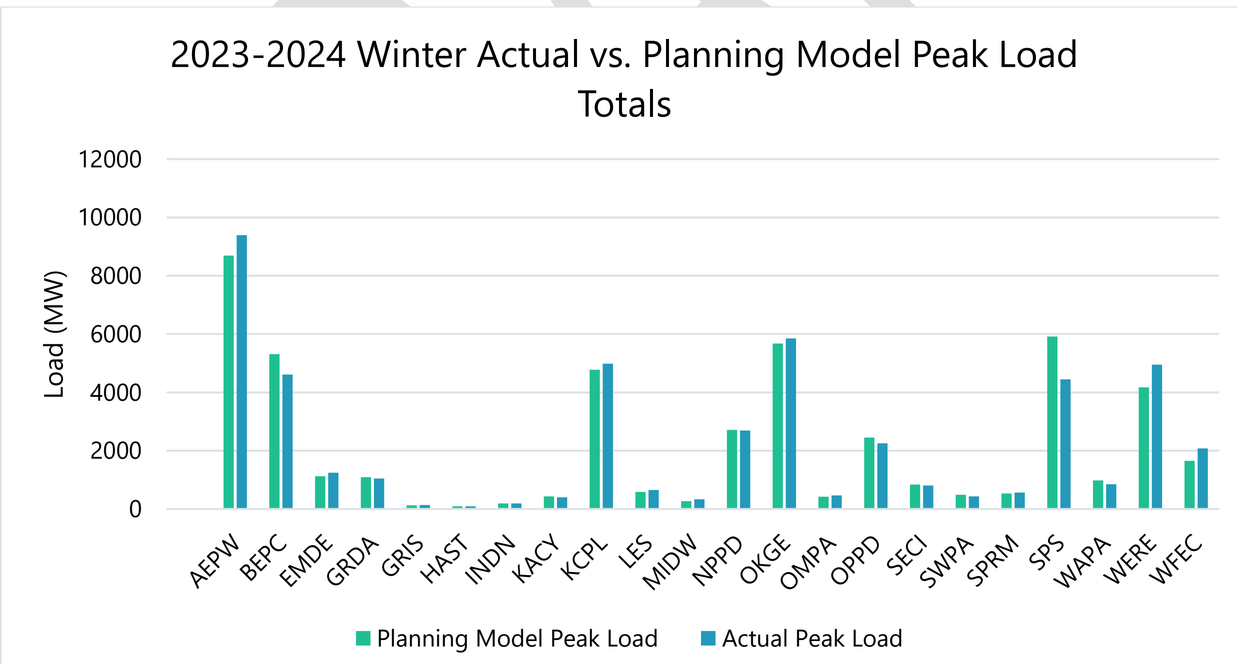

Figure 3.34: 2023-24 Winter Actual versus Planning Model Peak Load Totals

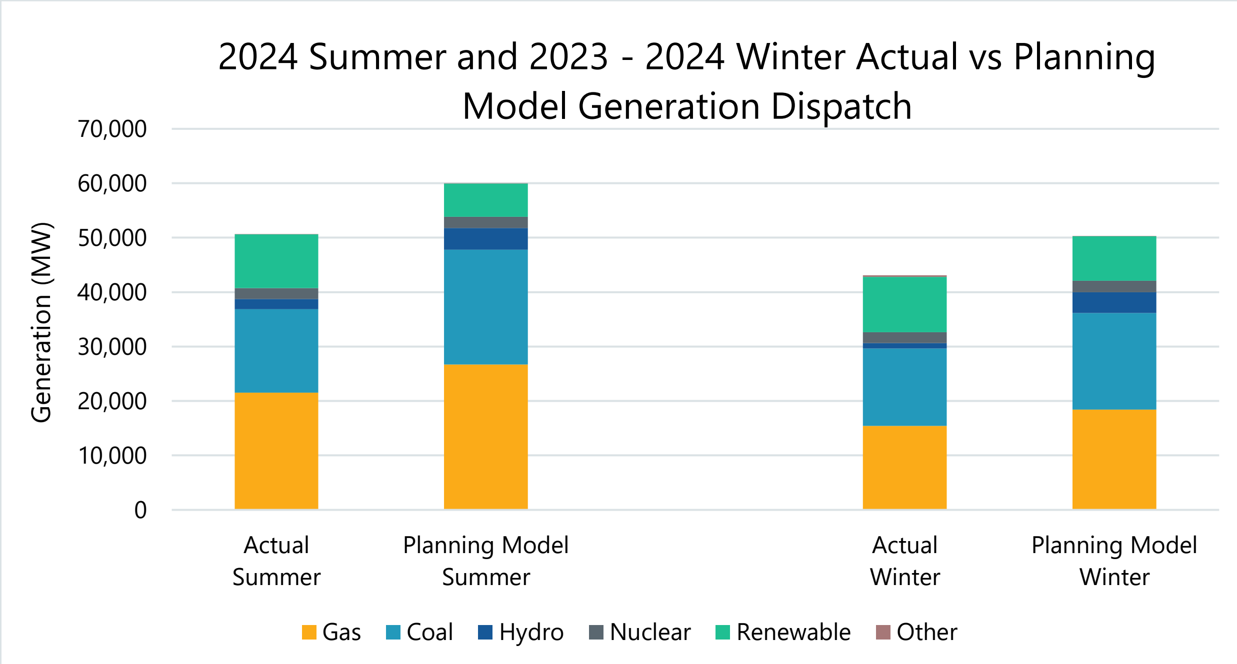

Figure 3.35: 2023 Summer and 2023-2024 Winter Actual vs Planning Model Generation Dispatch

3.5.2 MARKET ECONOMIC MODEL

3.5.2.1 *SYSTEM LOCATIONAL MARGINAL PRICE (LMP)*

Simulated LMPs were benchmarked against simulated LMPs from the 2023 ITP. This data was compared on an average monthly value-by-area basis. Figure 3.36 portrays the results of the benchmarking model for the SPP system. The increase in LMPs in the 2024 ITP is due to additional load in the Southwestern Public Service control area. The Crossroads to Hobbs to Road Runner 345 kV double circuit project, issued NTC from the 2021 ITP, would significantly decrease the LMP for the SPP system. Completion of this project will provide additional transmission capacity to serve new load in the SPS control area as well as reduce congestion. Sensitivity analysis performed with this upgrade in place yielded a reduction in SPP LMP of approximately 17%.

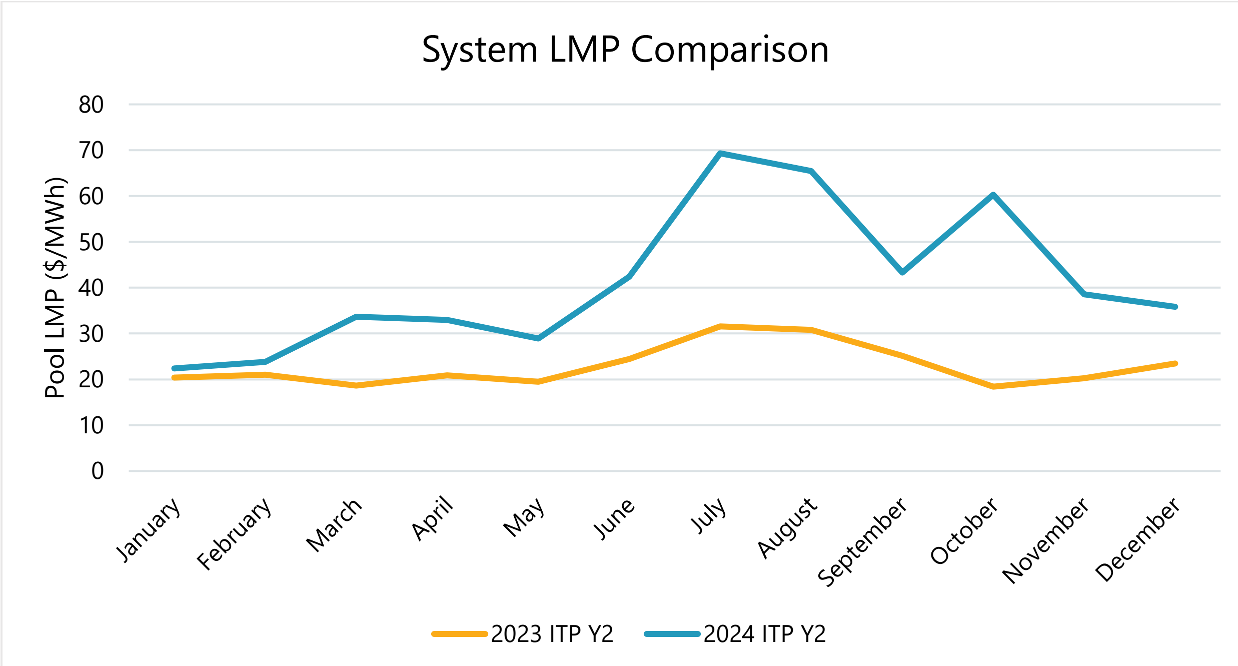

Figure 3.36: System LMP Comparison

3.5.2.2 *ADJUSTED PRODUCTION COST (APC)*

Examining the APC provides insight to which entities generally purchase generation to serve their load and which entities generally sell their excess generation. The resulting APCs for SPP zones were overall slightly higher in the 2024 ITP than in the 2023 ITP due to the change in load forecasts.

The APC on a zonal level both increases and decreases depending on the characteristics of the zone, including the level of renewable increase, retirements and zonal load forecast changes. See Figure 3.37 and Figure 3.38 for a summary of regional and zonal APC results.

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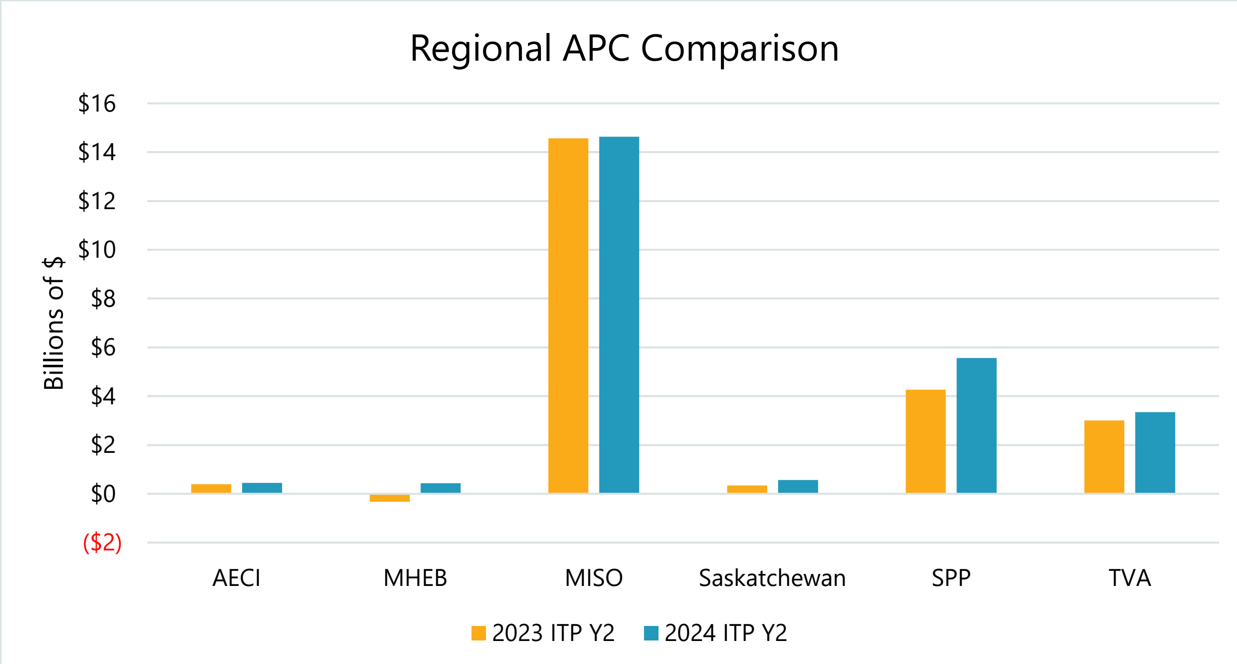

Figure 3.37: Regional APC Comparison

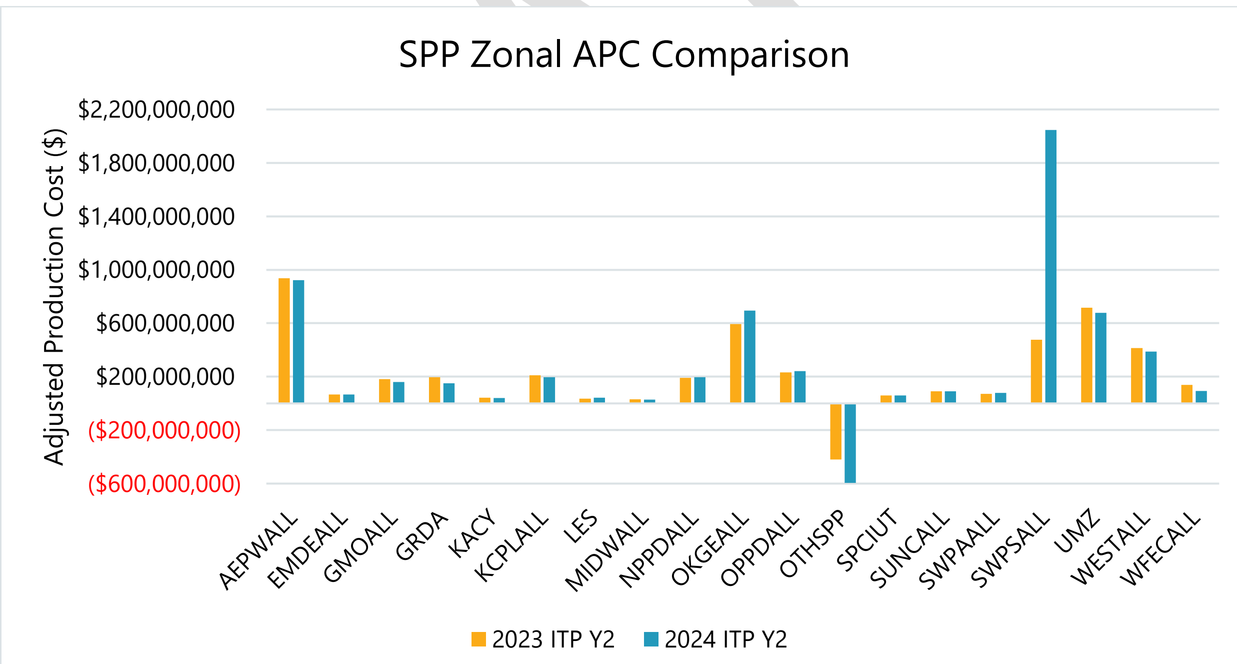

Figure 3.38: SPP Zonal APC Comparison

3.5.2.3 *INTERCHANGE*

The 2024 ITP model interchange was validated against the 2023 ITP and current SPP operations data. The duration curve of the 2024 ITP model is similar in shape and magnitude while overall exports are slightly lower in the 2024 ITP than in the 2023 ITP.

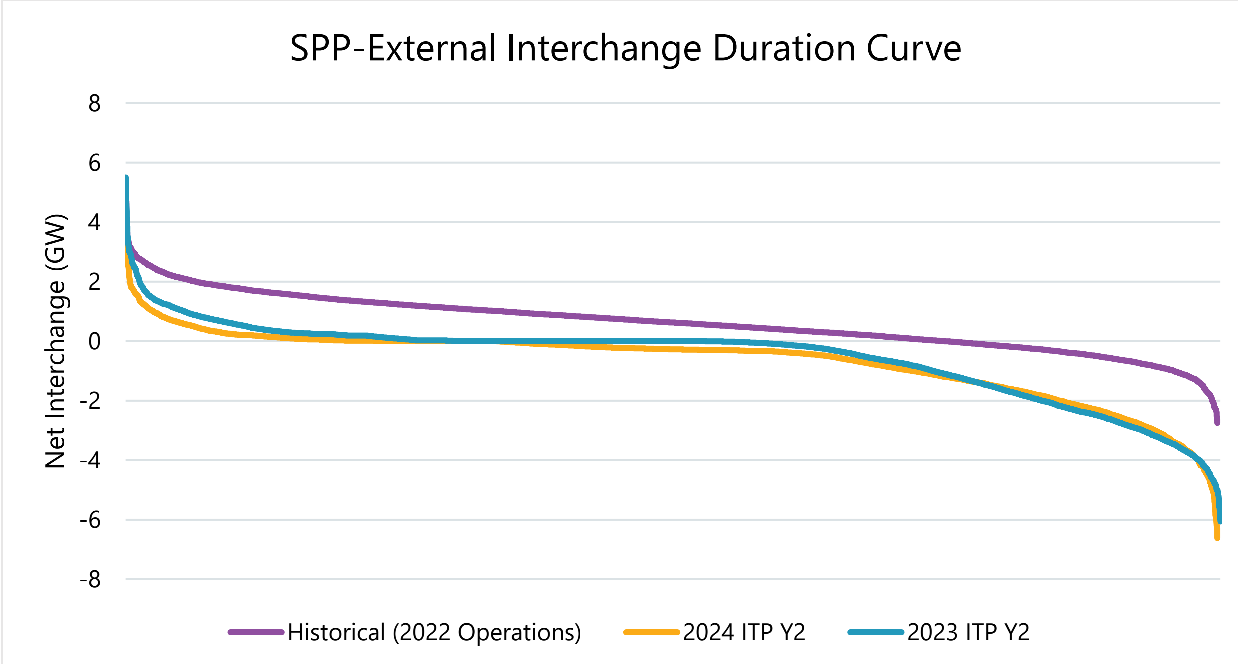

Figure 3.39: Interchange Data Comparison

3.5.2.4 *GENERATOR OPERATIONS*

3.5.2.4.1 CAPACITY FACTOR BY UNIT TYPE

Comparing capacity factors is a method for measuring the similarity between planning simulations and historical operations. This benchmark provides a quality control check of differences in modeled outages and assumptions regarding renewable, intermittent resources.

When comparing the capacity factors from the 2024 ITP to those reported to the EIA for 2022, SPP observed that the capacity factors for conventional generation from the 2024 ITP fell to slightly lower than the expected values. The difference in capacity factors between the datasets were attributed to differences in load forecasts as well as changes in the generation mix.

	Average Capacity Factor		
		2023 ITP	**2024 ITP**
Unit Type	**2022 EIA**	**Future 1 2024**	**Future 1 2025**
Nuclear	92.60%	88.56%	84.28%
Combined Cycle	56.70%	42.23%	39.27%
CT Gas	13.70%	4.86%	9.93%
Coal	47.80%	58.74%	53.13%
ST Gas	13.60%	3.30%	6.56%
Wind	36.10%	41.50%	43.18%
Solar	24.80%	31.91%	29.98%

Table 3.7: Generation Capacity Factor Comparison

3.5.2.4.2 AVERAGE ENERGY COST

Examining the average cost per megawatt-hour by unit type gives insight into what units will be dispatched first (without considering transmission constraints). Overall, the average costs per megawatt-hour were higher in the 2024 ITP than in the 2023 ITP due to the load forecasts and the difference in generation mix.

Unit Type	Average Energy Cost ($/MWh)	
	2023 ITP	2024 ITP
	Future 1 2024	Future 1 2025
Nuclear	$13.42	$13.75
Combined Cycle	$27.35	$29.96
CT Gas	$38.45	$42.60
Coal	$20.77	$20.93
ST Gas	$40.45	$36.06

Table 3.8: Average Energy Cost Comparison

3.5.2.4.3 GENERATOR MAINTENANCE OUTAGES

Generator maintenance outages in the simulations were compared to SPP real-time data. These outages have a direct impact on flowgate congestion, system flows and the economics of serving load.

The operations data includes certain outage types that cannot be replicated in these planning models. The difference in magnitude between the real-time data and the market economic simulated outages is due to the additional operational outages beyond those required by annual maintenance or driven by forced (unplanned) conditions. Although the market economic model simulation outages do not have as high a magnitude as the historical outages provided by SPP operations, the outage rates in the 2024 ITP are very similar to previous ITP assessments which indicates that the generator outages for the 2025 ITP are reasonable assumptions. The curves from the historical data and the market economic model simulations complemented each other very well in shape, building additional confidence in the generator outages represented in the 2025 ITP models.

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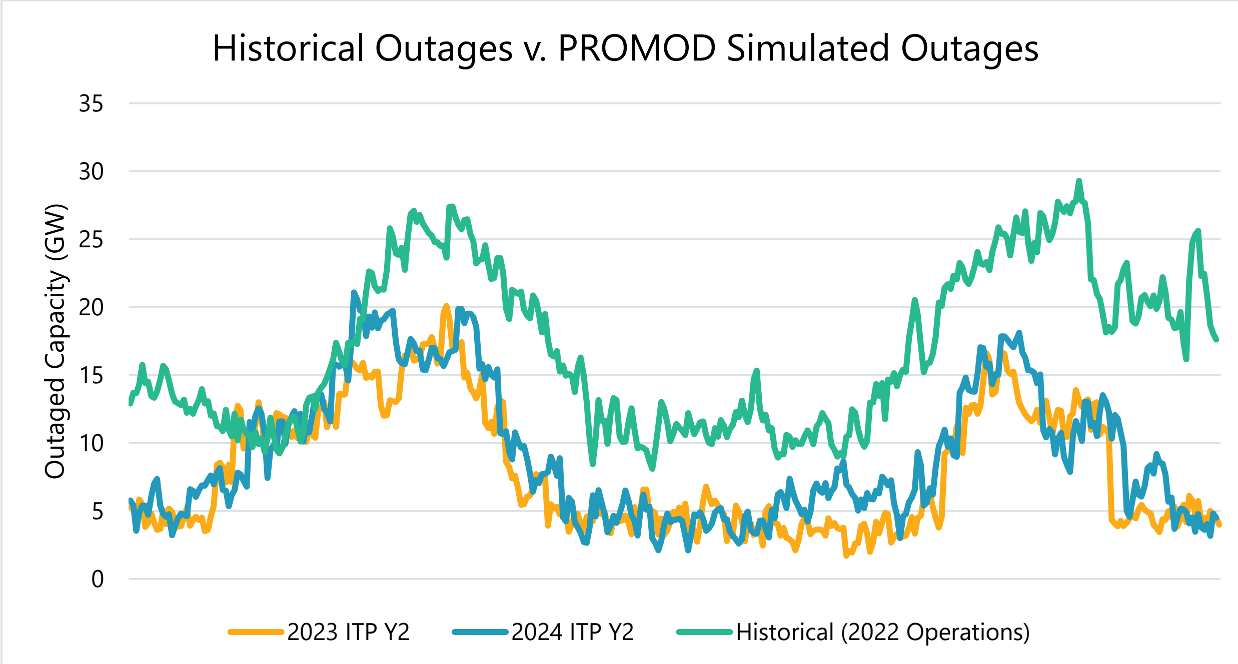

Figure 3.40: Historical Outages v. PROMOD Simulated Outages

3.5.2.4.4 OPERATING AND SPINNING RESERVE ADEQUACY

Operating reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of unplanned unit outages. The operating reserves should meet a capacity requirement equal to the sum of the capacity of largest unit in SPP and half of the capacity of the next largest unit in SPP. At least half of this requirement must be fulfilled by spinning reserve.

The operating reserve capacity requirement was modeled at 1,646 megawatts and spinning reserve capacity requirement was modeled at 823 megawatts. The reserve requirements were met in the market economic models. Figure 3.41 represents the operating and spinning reserves for each month.

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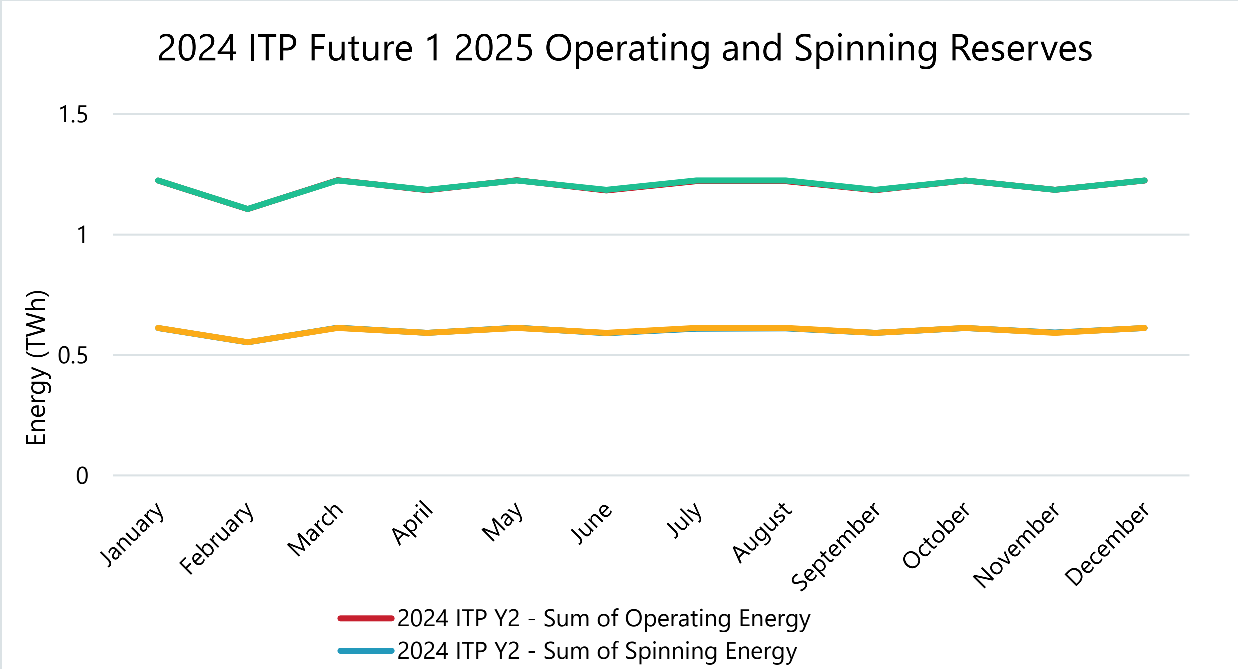

Figure 3.41: 2024 ITP Future 1 2025 Operating and Spinning Reserves

3.5.2.4.5 RENEWABLE GENERATION

Wind and solar energy output is higher in the 2024 ITP than in the 2023 ITP because of wind and solar generation additions identified during the generation review milestone. Wind output is greater due to the amount of installed capacity and approved RARs in 2024 ITP. The solar output is greater due to the updated methodology for matching the capacity factor to historical Operations data and four times the amount of available solar capacity for the 2024 ITP than in the 2023 ITP.

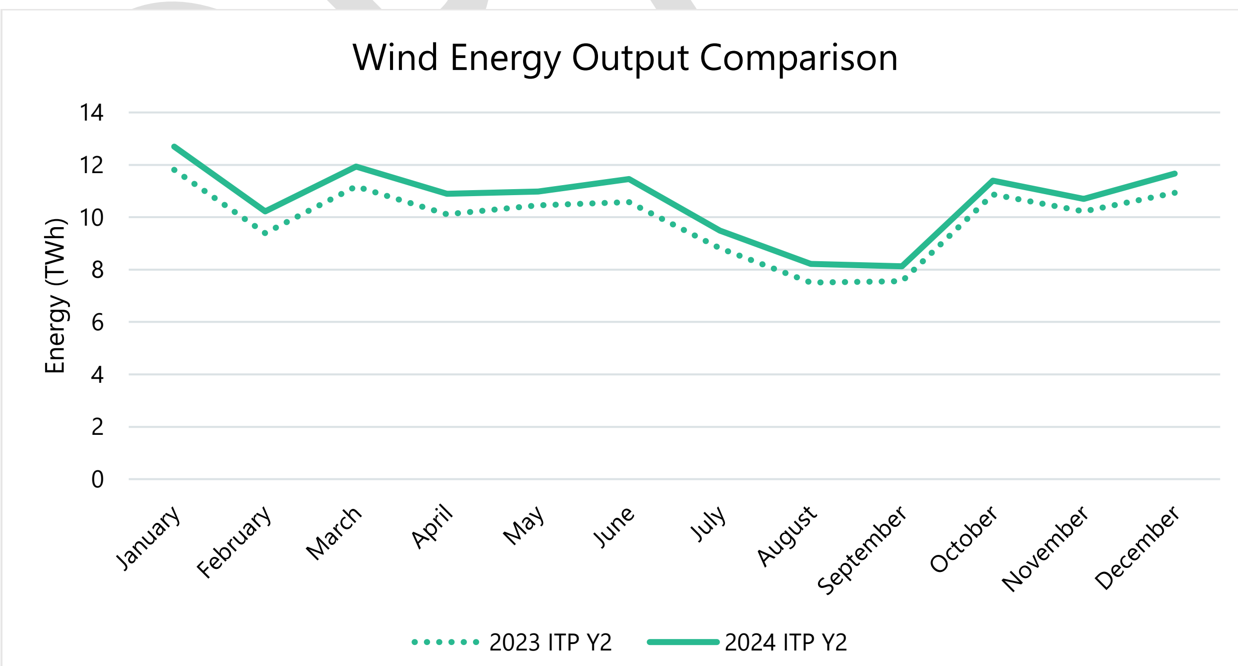

Figure 3.42: Wind Energy Output Comparison

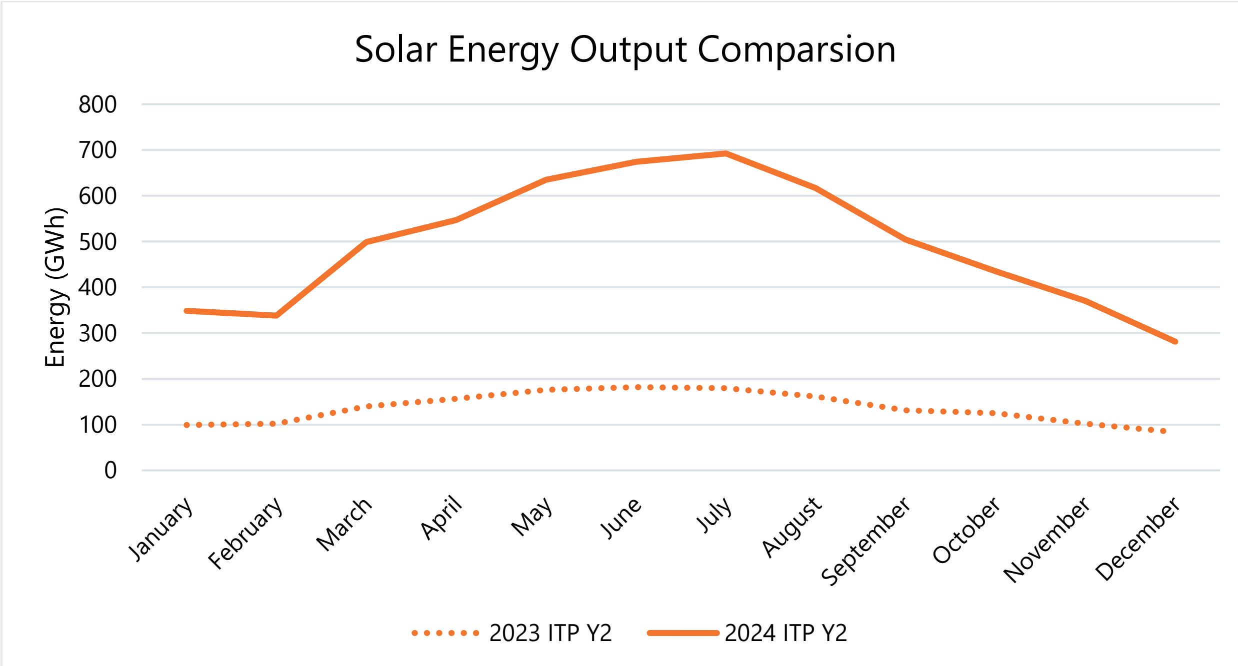

Figure 3.43: Solar Energy Output Comparison

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4 NEEDS ASSESSMENT

During each ITP Assessment, SPP and its member organizations collaborate to develop and analyze the regional transmission system's needs, identify robust solutions and develop a final portfolio.

4.1 ECONOMIC NEEDS

SPP determined economic needs based on the congestion score associated with a constraint (comprised of a monitored element and a contingent element pair). SPP calculated the congestion score by multiplying the number of hours a constraint is congested in the model by the average shadow price of that constraint.

Unique constraints with a congestion score greater than $50,000/MW were identified as economic needs within each future. Additional constraints with the same monitored element paired with a different contingency were also included if this congestion score threshold was met. Some needs appeared in multiple futures.

There were 320 unique economic needs (monitored-contingent element pairs) in the 2024 ITP – nearly three-and-a-half times that of the 2023 ITP. SPP observed the largest congestion scores in these three SPP areas: Omaha (OPPD), New Mexico (SPS), and Williston (UMZ). This aggressive congestion is attributed to large load growth beyond the ability of the transmission system to deliver. A high number of monitored constraints contributed to the increased number of economic needs overall. While not the focus of the ITP, some facilities outside of the SPP footprint also observed high congestion scores. To be identified as a need, external facilities must meet the congestion score threshold and provide at least one million dollars in potential benefit to SPP's region. Other notable congestion was observed in Northwest North Dakota, Eastern South Dakota, Northeast Kansas/Western Missouri, Southwest Missouri, Northeast Oklahoma, and Northwest Texas.

SPP observed the impact of reliability needs on the economic models. In the 2024 ITP economic models, these reliability needs contributed to severely congested transmission which led the powerflow software to dispatch more expensive "emergency energy" to serve load. This created a high Adjusted Production Cost (APC) in the base economic models. More affordable generation could not serve this load because the software is designed to honor transmission constraints. The 2024 ITP portfolio removes the need for the dispatch of this expensive "emergency energy," greatly reducing the APC.

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Table 4.1 shows the top 25 economic needs and their corresponding scenarios. A full list of all economic needs identified in the 2024 ITP Needs Assessment document can be found on GlobalScape.[30]

Constraint Name	Scenario	Max Congestion Score
Sub 1250 - Sub 1358 161 kV circuit 1 FTLO (For the loss of) Base Case	All	52,560,000
Sub 1209 - Sub 1358 161 kV circuit 1 FTLO Sub 1251 - Sub 1297 161 kV circuit 1	All	42,872,978
Sub 1209 - Sub 1358 161 kV circuit 1 FTLO Sub 1250 - Sub 1297 161 kV circuit 1	All	24,465,118
Robinson Lake - Finstad 115 kV circuit 1 FTLO Palermo - Blaisdell 115 kV circuit 1	All	19,073,807
Sub 1209 - Sub 1358 161 kV circuit 1 FTLO Sub 701 - Sub 1211 161 kV circuit 1	All	19,013,867
Sub 1209 - Sub 1358 161 kV circuit 1 FTLO Base Case	All	15,105,356
Finstad - Vanhook 115 kV circuit 1 FTLO East New Town - Vanhook 115 kV circuit 1	Years 5 & 10	13,485,616
Wahpeton 115/230 kV Transformer circuit 2 FTLO Wahpeton 115/230 kV Transformer circuit Z	Years 5 & 10	13,013,143
Finstad - Vanhook 115 kV circuit 1 FTLO Finstad - Vanhook MW7 115 kV circuit 1	Years 5 & 10	12,041,853
Lynch - Pearle 115 kV circuit 1 FTLO Cunningham Quahada Tap - Quahada 3 115 kV circuit 1	Years 5 & 10	9,937,586
Lynch - Pearle 115 kV circuit 1 FTLO Cunningham 3 - Quahada 3 115 kV circuit 1	All	8,083,569
[External] Swift Current 138/230 kV Transformer circuit 2 FTLO Swift Current 138/230 kV Transformer circuit 1	All	7,833,375
Eastfork - Folvag 115 kV circuit 1 FTLO Northwest Williston Tap - North Williston 115 kV circuit 1	All	7,077,842
Robinson Lake - Finstad 115 kV circuit 1 FTLO Palermo - Stanley 115 kV circuit 1	All	6,941,965
Osborn - Vanhook 115 kV circuit 1 FTLO East Newton - Vanhook MW7 115 kV circuit 1	All	5,214,518
Southwestern Public Service - New Mexico Tie Interface (SPSNMTIES) FTLO Base Case	All	4,329,851
Hess Gas - Neset 115 kV circuit 1 FTLO North Tioga - Neset 115 kV circuit 1	All	4,257,585
Osborn - Vanhook 115 kV circuit 1 FTLO Finstad - Vanhook MW7 115 kV circuit 1	Years 5 & 10	3,752,436
North Tioga - Neset 115 kV circuit 1 FTLO Hess Gas - Neset 115 kV circuit 1	All	3,497,486

[30] The 2024 ITP needs list can be found on GlobalScape under *ITP → ITP → NCD (CEII, RSD) → NDA → 2024 ITP →* ***2024 ITP Needs Assessment.***

Constraint Name	Scenario	Max Congestion Score
Sub 1209 - S1358 161 kV circuit 1 FTLO Council Bluffs - Sub 3456 345 kV circuit 1	All	3,315,211
[External] Coteau 138/230 kV Transformer circuit 1 FTLO Herbert - Pasqua 230 kV circuit 1	All	3,029,151
Northwest Williston Tap - North Williston 1151 kV circuit 1 FTLO Eastfork - Folvag 115 kV circuit 1	All	2,963,985
Weaver - Tallgrass 138 kV circuit 1 FTLO Benton - Midian 138 kV circuit 1	All	2,775,757
Bismark - Bismark Expressway 115 kV circuit 1 FTLO Ward - Bismark 230 kV circuit 1	All	2,330,908
[External] Belle Plaine - Pasqua 138 kV circuit 1 FTLO Pasqua - Condie Line - Grid Line Tap at Pasqua 230 kV circuit 1	Years 5 & 10	1,891,346

Table 4.1: 2024 ITP Top 25 congested constraints

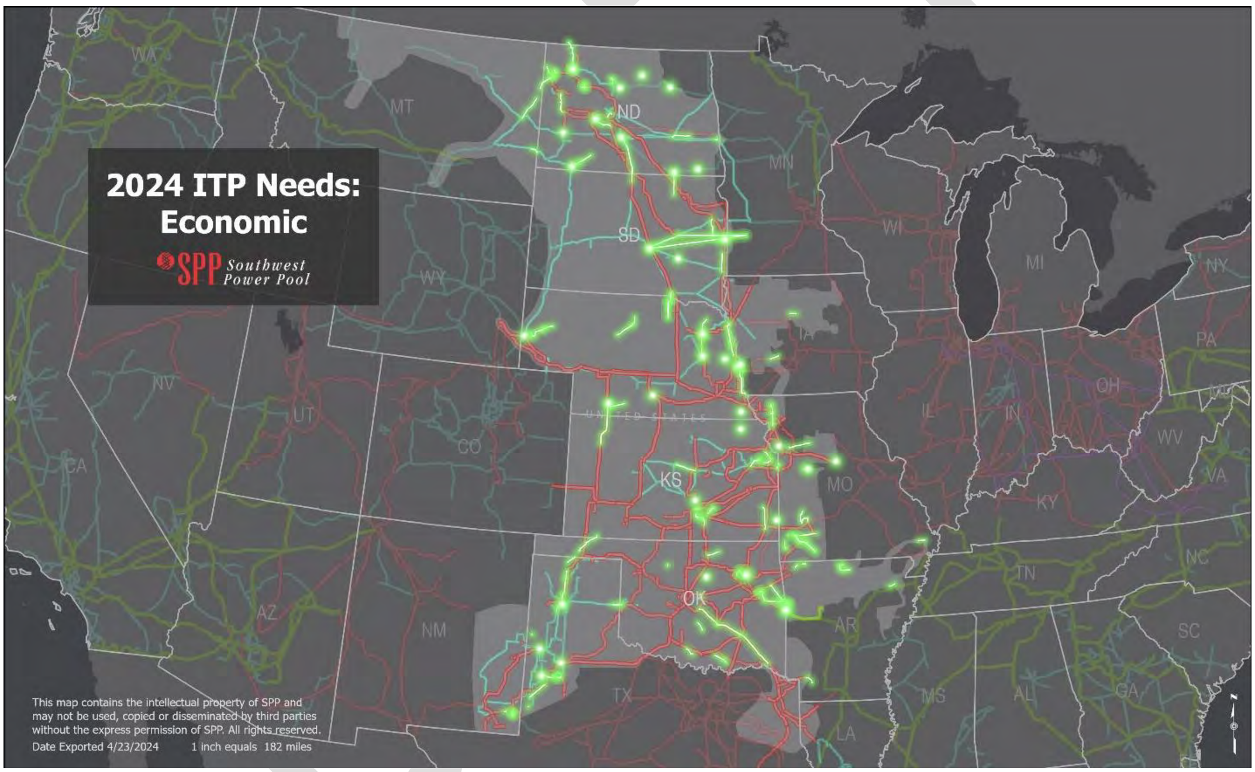

Figure 4.1: 2024 ITP Economic Needs Map - SPP Only

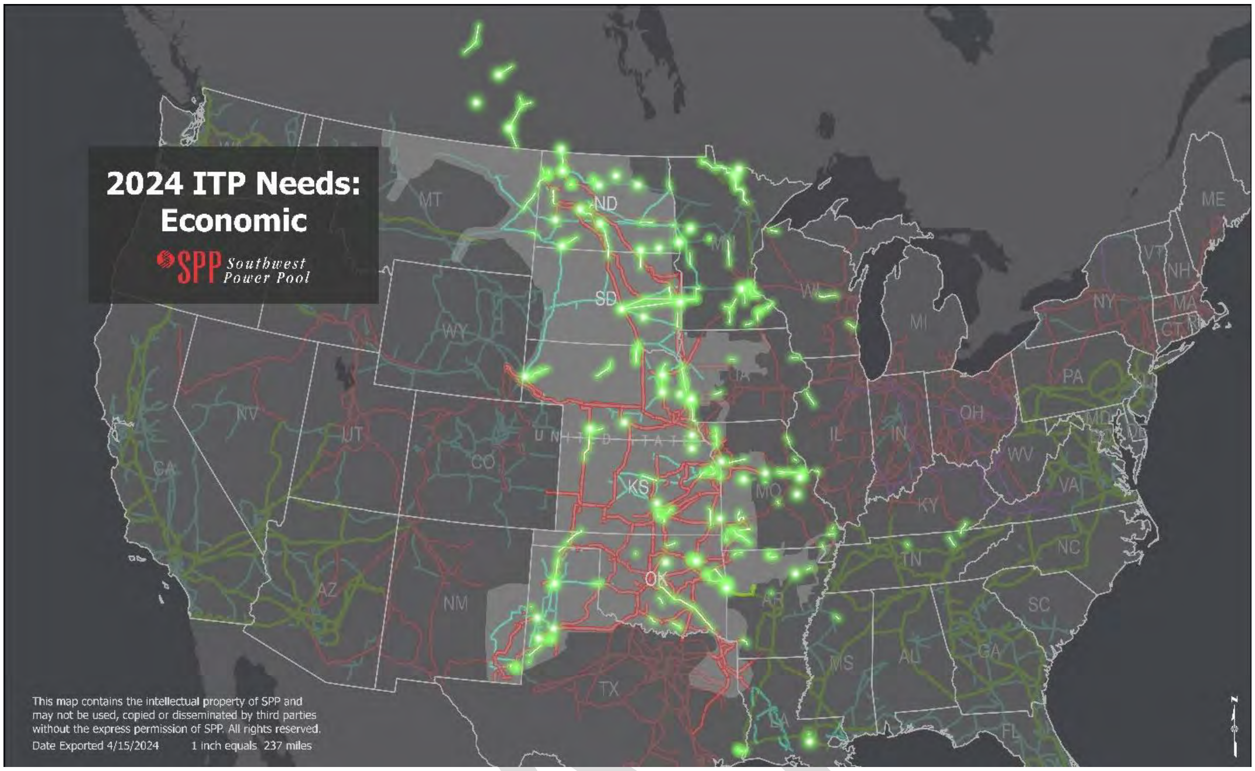

Figure 4.2: 2024 ITP Economic Needs Map - SPP & External Areas

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4.2 RELIABILITY NEEDS

4.2.1 BASE RELIABILITY ASSESSMENT

Contingency analysis for the base reliability models consisted of analyzing P0, P1 and P2.1 planning events from Table 1 in the NERC TPL-001 standard, as well as remaining events that do not allow for non-consequential load loss or the interruption of firm transmission service.

During the needs assessment, potential violations were solved or marked as invalid through methods such as reactive device settings adjustments, model updates, and identification of invalid contingencies, non-load-serving buses and facilities not under SPP's functional control. SPP posted preliminary violations ahead of the needs assessment to provide TOs with the opportunity to review the violations and provide invalidation feedback. Feedback was incorporated prior to the posting of the needs and opening of the detailed project proposals (DPP) window. Stakeholder feedback refined the final list of identified needs, helped staff remove invalid needs and improved the quality of DPPs submitted by stakeholders. The final base reliability needs list identified 632 unique needs. For reference, this was more than seven times the number of needs identified in the 2023 ITP.

Figure 4.3 and Figure 4.4 summarize the final quantities of thermal and voltage needs that remained after mitigations were evaluated during the screening process and Figure 4.5 and Figure 4.6 shows the geographical locations of the needs.

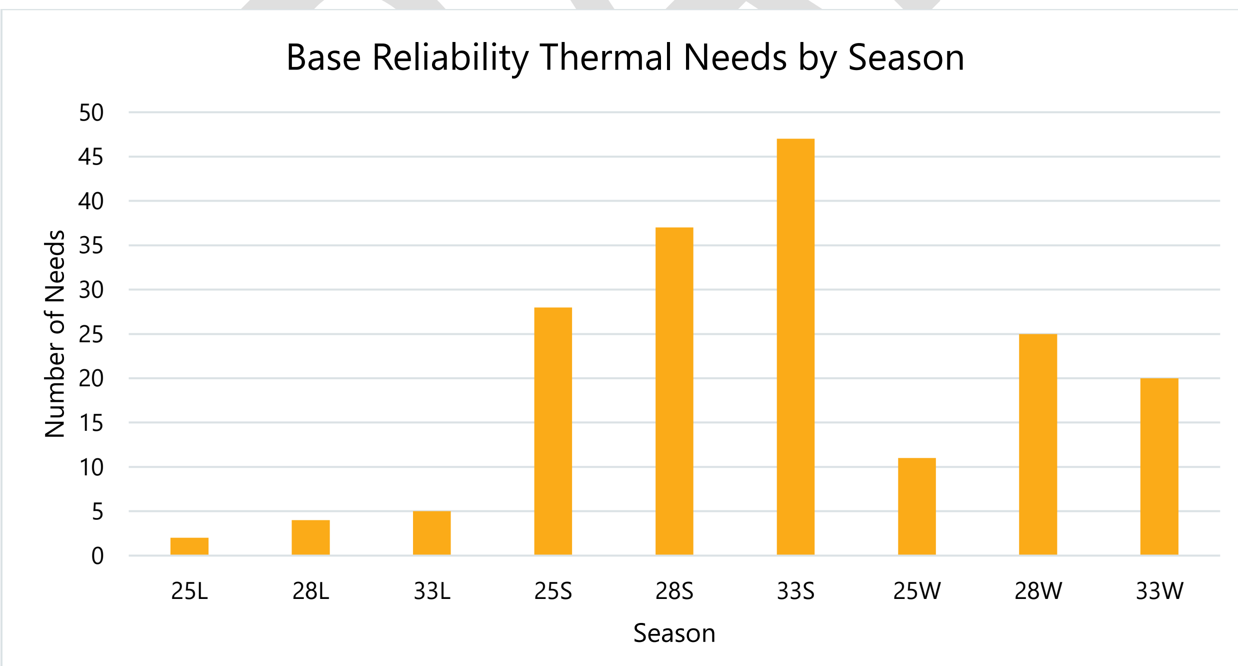

Figure 4.3: Unique Base Reliability Thermal Needs by Season

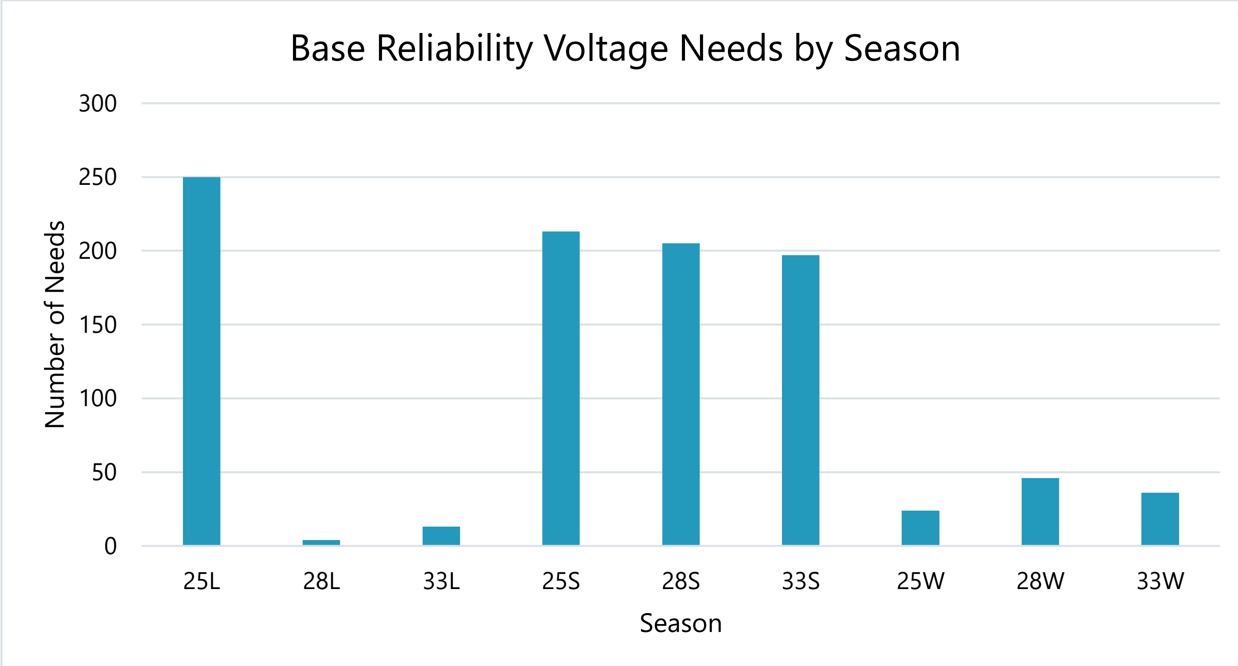

Figure 4.4: Unique Base Reliability Voltage Needs by Season

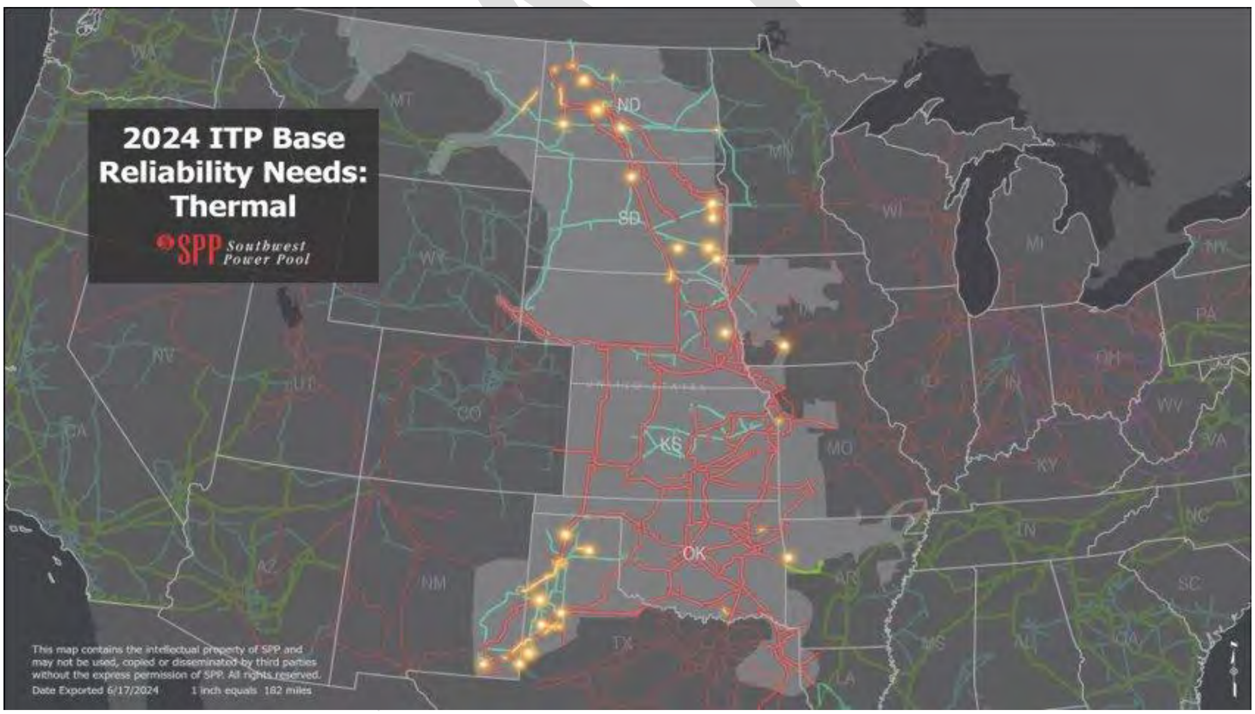

Figure 4.5: Base Reliability Needs - Thermal

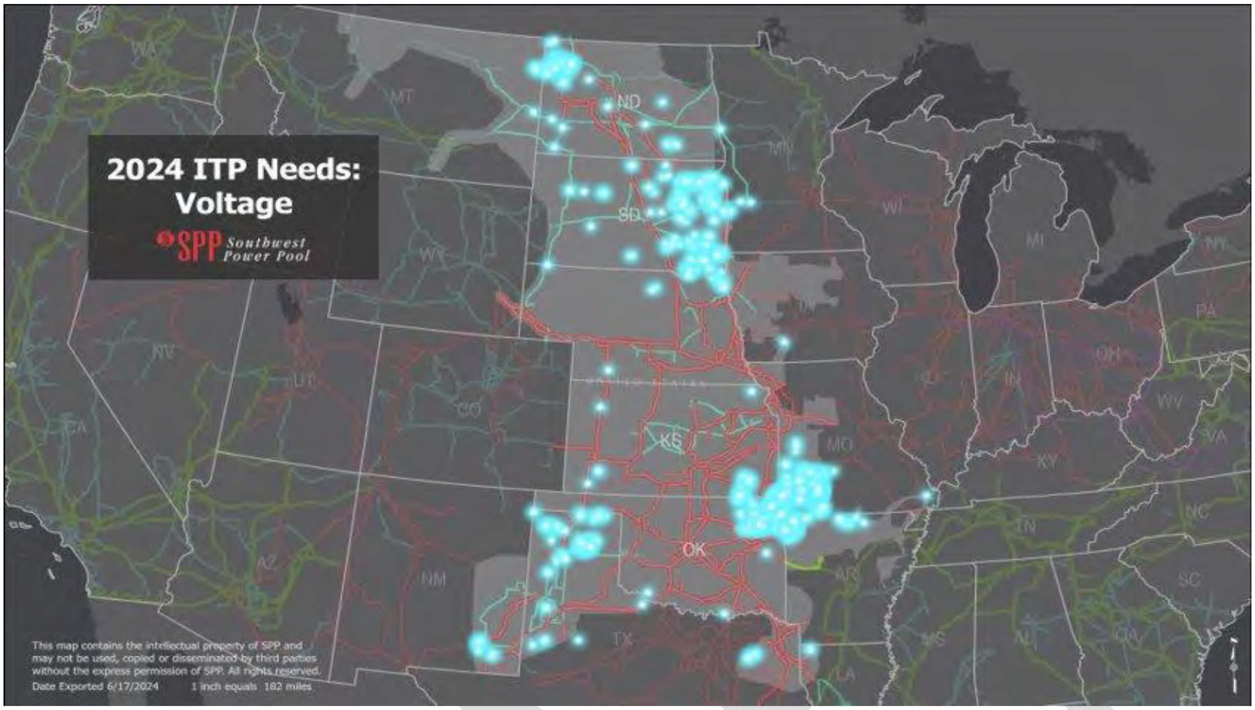

Figure 4.6: Base Reliability Needs - Voltage

4.2.2 NON-CONVERGED CONTINGENCY CASES

SPP used engineering judgment to resolve non-converged cases from the contingency analysis. All non-converged cases were resolved either through alternate powerflow solve methodologies, model corrections, or the contingencies were determined to be invalid. Nonconvergence due to voltage collapse conditions was observed in all base reliability cases. The voltage collapse cases indicated the need for additional transmission to provide voltage support in the area. The two main areas where SPP staff observed voltage collapse were southern New Mexico and North Dakota around Lake Sakakawea.

4.2.3 SHORT-CIRCUIT ASSESSMENT

SPP provided the total bus fault current study results for single-line-to-ground (SLG) and three-phase faults to Transmission Planners (TPs) for review.

TPs were required to evaluate the results and indicate if any fault-interrupting equipment would have its duty ratings exceeded by the maximum available fault current. For equipment that would have its duty ratings exceeded, the TP provided the applicable duty rating of the equipment, and SPP identified the violation as a short-circuit need.

While still abiding by the requirements of TPL-001, the TPs could have performed their own short-circuit analysis to identify corrective actions plans. However, any corrective action plans that result in the recommended issuance of an NTC are based on the SPP short-circuit analysis.

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The TPs that identified short-circuit needs were Oklahoma Gas and Electric Company and Omaha Public Power District. The needs are depicted in Figure 4.7.

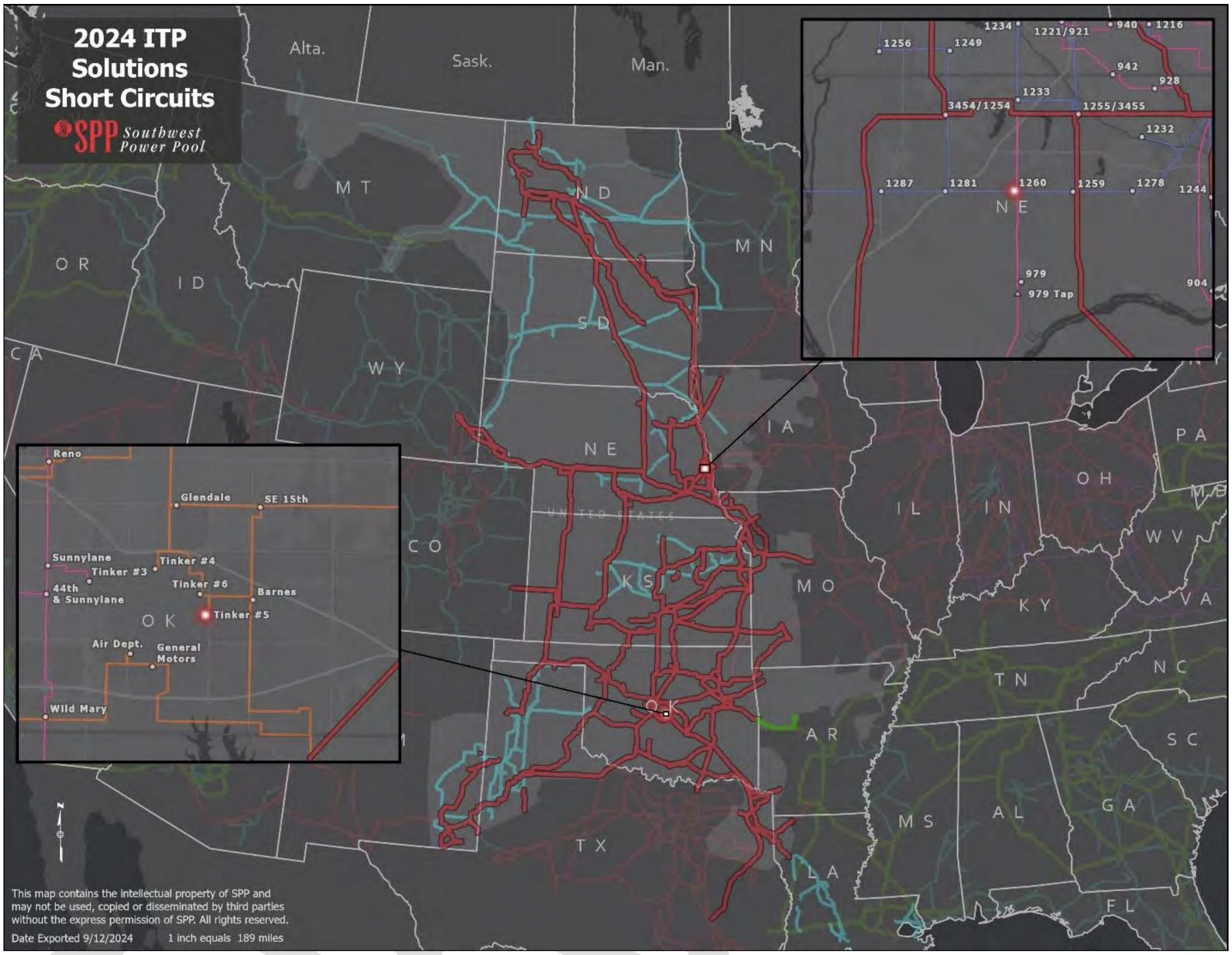

Figure 4.7: Short-Circuit Needs - Overdutied Breakers

4.3 PUBLIC POLICY NEEDS

SPP identifies policy needs by evaluating the curtailment in renewable energy generation, which may prevent utilities from meeting their energy-based renewable portfolio standards. SPP assessed each region's renewable energy targets at a utility-specific level to determine compliance with the mandates or goals. Policy needs arise from the inability to deploy renewable generation due to congestion, impacting the utilities' ability to fulfill their state-specific renewable goals or mandates. In the 2024 ITP, all utilities successfully achieved their renewable targets, resulting in no identified policy needs.

4.4 PERSISTENT OPERATIONAL NEEDS

4.4.1 ECONOMIC OPERATIONAL NEEDS

SPP can identify economic operational needs if a flowgate was congested for at least 20% of intervals or if it experienced at least $10 million in congestion costs over the previous 24 months.

SPP did not identify any economic operational needs where a flowgate was congested for at least 20% of the previous 24 months, either in a breached or binding state in the real-time balancing market.

SPP identified 12 facilities with a congestion cost totaling more than $10 million over the previous 24 months and four facilities with a congestion cost totaling more than $50 million over the previous 24 months. Some of these needs were already addressed by existing NTCs. Economic operational needs that did not already have NTCs for the 2024 ITP are listed in Table 4.2.

Monitored Element	Contingent Element	Congestion Cost Criteria
Carpenter - Hitchland 345 kV Liberal - Texas County 115 kV Jericho - Kirby SW Station 115 kV Sweetwater - Wheeler 230 kV Shamrock - Mclean South 115 kV Oklaunion - Tuco 345 kV Beaver County - Hitchland #1 345 kV Beaver County - Hitchland #2 345 kV Border - Tuco 345 kV		> $50 million
Overton 345/161 kV Transformer	Overton - McCredie 345 kV	> $50 million
Conway - Kirby 115 kV	Nichols - Grapevine 345 kV	> $50 million
Cimarron 345/138 kV XF 3	Cimarron - Draper 345 kV	> $50 million
Nashua 345/161 kV Transformer	Nashua - Hawthorn 345 kV	> $10 million
Cimarron 345/138 kV XF 3	Cimarron - Draper 345 kV	> $10 million
Monett - Aurora 161 kV	Blackberry - Jasper 345 kV	> $10 million
Smokey Hill - Summit 230 kV	Macon - Axtell 345 kV	> $10 million
County Line - Tecumseh Hill 115 kV	Sibley - Overton 345 kV	> $10 million
South Road - Roman 138 kV	Redington - Mathewson 345 kV	> $10 million
Edwardsville 115/161 kV XF	87th Street - Craig 345 kV	> $10 million
Tekamah - Sub 1226 161 kV	Ft Calhoun - Ft Calhoun 345 kV	> $10 million
Tahlequah - Highway 59 161 kV	Muskogee - Ft Smith 345 kV	> $10 million
Smokey Hill - Summit 230 kV	South Hays - Mullergren 230 kV	> $10 million
Marmaton - Neosho 161 kV	Jayhawk - Franklin 161 kV	> $10 million
Smokey Hill - Summit 230 kV	Mullergren - Circle 230 kV	> $10 million

Table 4.2: Economic Operational Needs - Congestion

SPP also identified economic operational needs based on manual commitments of uneconomic generation for local area voltage support. SPP designated manual commitments of a unit as a need if they occurred either 25% of the year or cost more than $1 million over 24 months. SPP identified two economic operational needs based on manual commitments, listed in Table .

Local Area	Unit Committed
SPS	Harrington
SPS	Tolk

Table 4.3: Economic Operational Needs - Manual Commitments

4.4.2 RELIABILITY OPERATIONAL NEEDS

SPP identified four facilities as operational reliability needs that did not already have NTCs for the 2024 ITP. All four of the needs were thermal loading issues where system reconfiguration was implemented in real-time 25% or more of the year.

Facility	Cause
Red Willow	Thermal Loading
Snyder	Thermal Loading
South Hays	Thermal Loading
Warrensburg East	Thermal Loading

Table 4.4: Reliability Operational Needs

New criteria for identifying persistent operational needs were introduced in the 2024 ITP. The new criteria were a result of a revision to the ITP Manual that aimed to align criteria with portions of the SCRIPT T3 recommendations. The objective of the recommendation was to clarify which SPP flowgates would be included in the list of flowgates and to classify facilities as economic needs or reliability needs. Facilities that experienced congestion due to planned or forced historical outages would be classified as economic needs. Facilities where pre-contingency or post-contingency facility ratings or voltage exceedances were experienced in real-time operations would be classified as reliability needs.

The identification of these real time events improves system flexibility by addressing operational issues that can enhance the flexibility of the transmission system. This is crucial in accommodating changing energy demands, integrating new generation sources, and supporting emerging technologies such as energy storage. A more flexible approach can adapt to evolving needs and reduce the need for costly infrastructure investments. It will also enhance resiliency using persistent operational events that undermine the robustness.

SPP identified 77 facilities as operational reliability needs based on System Operating Limit exceedances that have occurred in real-time operations where the total cumulative time exceeded four days over the

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previous 24 months. Of the 77 facilities, 52 were voltage exceedances and the remaining 25 were thermal exceedances.[31]

4.5 WINTER WEATHER NEEDS

Stakeholders defined winter weather needs as facilities with violations exceeding emergency ratings in the base case of the winter weather models. In this instance, base case is intended to mean the conditions of the models as built, which includes prior outage conditions. Transmission lines and transformers with thermal loading of 100% or greater of their emergency ratings were identified as needs. Buses with voltages outside of the acceptable bandwidth of 0.90 p.u. to 1.05 p.u. were also identified as needs. SPP also performed a contingency analysis on the winter weather models P1 and P2.1 planning events from Table 1 in the NERC TPL-001 standard.

SPP staff posted all thermal and voltage violations observed in the base cases as needs. Violations resulting from contingencies were included in the needs list as informational.

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[31] The thermal exceedance of Maryville – Midway 161kV and the related 161kV corridor in Northwest Missouri area are being evaluated as part of the 2024 JCSP assessment. If a solution is not reached, these issues will be addressed as part of the 2025 ITP study.

5 PORTFOLIO DEVELOPMENT AND PROJECT SELECTION

5.1 SOLUTION EVALUATION

SPP evaluated each solution in each applicable model scenario to determine their effectiveness in mitigating the needs identified in the needs assessment.

The solutions evaluated were comprised of:

- Federal Energy Regulatory Commission (FERC) Order 1000 and Order 890 solutions submitted by stakeholders
- SPP staff-developed solutions
- model adjustments and model corrections

SPP analyzed 968 DPPs and approximately 1,100 staff-developed solutions. SPP calculated a conceptual cost estimate for each solution based on a standardized conceptual cost template.[32] SPP utilized the conceptual cost during solution screening.

5.1.1 RELIABILITY SOLUTION SCREENING

SPP tested solutions to determine their ability to mitigate reliability criteria violations in the study horizon. SPP deemed solutions to be effective if they resolved system violations to a level allowed by the SPP Planning Criteria or members' more stringent local planning criteria, as applicable. Figure 5.1 illustrates the reliability project screening process.

Reliability metrics were developed by SPP and stakeholders. SPP calculated these metrics for each project and used them as a tool to develop a portfolio of projects to address all reliability needs. The first metric was a cost per loading relief (CLR) score, which relates the amount of thermal loading relief a solution provides to its engineering and construction (E&C) cost. The second metric was cost per voltage relief (CVR) score, which relates the amount of voltage support a solution provides to its E&C cost.

[32] SPP OATT Business Practices, Section 8

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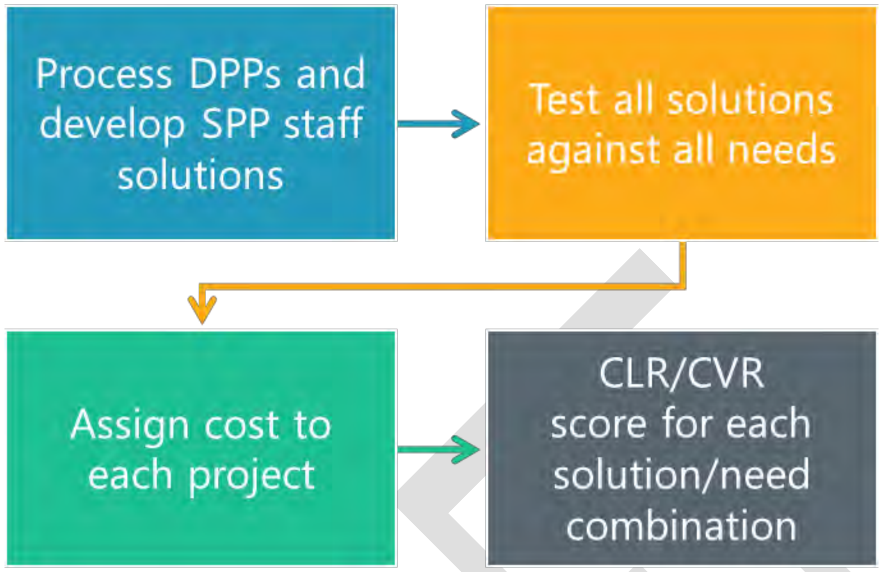

Figure 5.1: Reliability Project Screening Process

5.1.2 ECONOMIC SOLUTION SCREENING

SPP evaluated solutions to determine their effectiveness in mitigating transmission congestion in the 10-year study horizon. SPP calculated a one-year B/C ratio and a 40-year present value (PV) B/C ratio for each project based on its Adjusted Production Cost (APC) savings in each future and study year.

SPP determines the one-year benefit to the SPP region for each study year by calculating the annual change in APC for all SPP pricing. SPP calculated the one-year B/C ratio for each project by dividing the one-year benefit by the one-year cost of the project. The one-year cost, or projected Annual Transmission Revenue Requirement (ATRR), is calculated using the historical SPP median of the two-year net plant carrying charge (NPCC) for the TO multiplied by the project's conceptual cost. SPP used an SPP-average NPCC of 16.15% for projects assigned to non-SPP TOs in this assessment. SPP calculated the 40-year project cost using these NPCCs, an 8% discount rate, and a 2.0% inflation rate.

SPP used two event files during screening to reduce economic simulation run times and to obtain more accurate APC savings values in areas where emergency energy was a concern. SPP staff did this by modifying one version of the event file to have key constraints relaxed that were causing emergency energy and heavy congestion, and by removing events that were not binding. SPP did not modify the other event file.

During the economic screening process, SPP identified instances where congestion correlated across different areas of the system. These correlations indicated that the usefulness of the event files in identifying congestion more precisely would be improved by monitoring additional constraints. Improving the event files involved adding new flowgates to the screening simulations where necessary to capture potential congestion caused by new projects. Additionally, SPP paired solutions to address related congestion with a more comprehensive approach. These adjustments helped ensure that the projected benefits of the solutions were accurately represented.

5.1.3 PERSISTENT OPERATIONAL SOLUTION SCREENING

SPP provided the persistent economic operational needs for informational purposes only. However, many persistent economic operational needs were also identified as an economic need in the near-term planning horizon. SPP screened solutions addressing those needs using the economic solution screening criteria.

5.1.4 WINTER WEATHER SOLUTION SCREENING

SPP evaluated solutions that addressed winter weather needs in the target area similarly to reliability needs. SPP tested every solution against every need, assigned conceptual costs, and calculated CLR and CVR scores. The holistic approach to solving needs in the target area required evaluating how well groups of high performing projects performed together. SPP evaluated the economic benefits of each winter weather solution to aid in project selection.

SPP also evaluated solutions that increased north to south transfer capability across the Nebraska-Kansas border. The methodology included ramping up generation in the north, then ramping down generation in the south until base case voltage collapse occurred. SPP applied individual projects and groups of projects to the models and then re-evaluated the system's transfer capability. SPP then compared the transfer capability to the base case to determine the effectiveness of solutions. The following sections describe the methodology in more detail.

5.1.4.1 *WINTER WEATHER TRANSFER STUDY*

A voltage stability assessment was conducted with the generic winter weather powerflow models (based on winter storm Uri) to assess the transfer limit (GW) from SPP North to SPP South across the Nebraska-Kansas border. The purpose is to address EHV congestion observed during extreme winter weather scenarios. Following this the same transfer was conducted with individual projects applied to the model. Projects were then selected based on the transfer capability attributed to each project. More than 150 projects and project groupings were studied.

5.1.4.1.1 METHODOLOGY

To determine the amount of generation transfer that could be accommodated by each planned system, generation in the source zone (SPP North then MISO North) was increased and generation in the sink zone (SPP South) was decreased. Figure 5.2 identifies the transfer zones and boundaries.

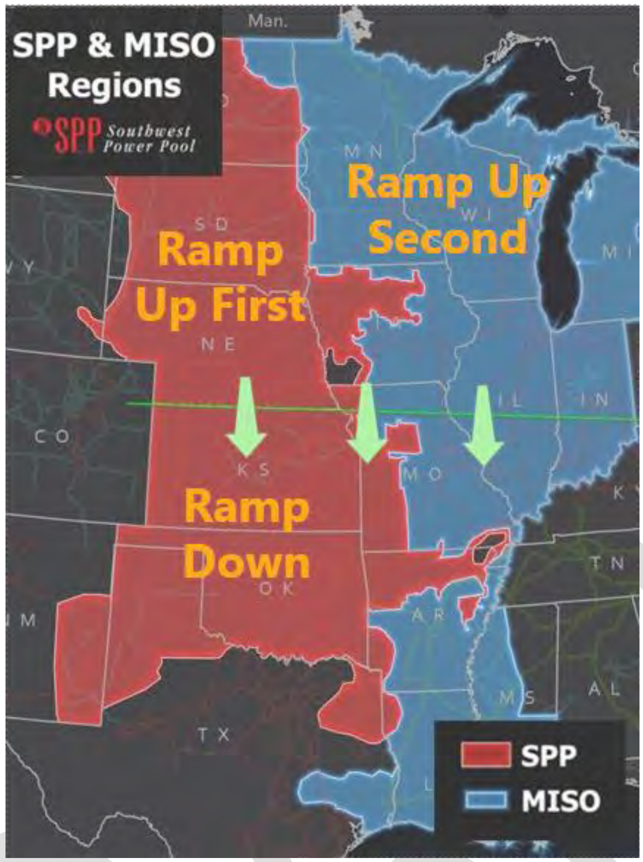

Figure 5.2: SPP & MISO Transfer Zones & Boundaries

Kansas, Nebraska, Missouri, and the surrounding areas were monitored for voltage at 1.05 to 0.95 p.u. and thermal at 100% or above for violations. Transfer capability was determined by base case transfer amount prior to voltage collapse.

Single contingencies (N-1) for all SPP branches, transformers, and ties greater than or equal to 345 kV were monitored. SPP and first-tier 100 kV and above facilities were monitored for voltage and thermal violations. The initial condition for each model was the source zone sum of real power generation output (MW). The maximum source zone transfer capability was the sum of the SPP North and MISO North's conventional real power maximum generation (Pmax). The transfer analysis was performed on the year 10 model in 50 megawatt steps until voltage collapse occurred in the pre-contingency and post-contingency (N-1, 345 kV and 500 kV facilities) conditions. Each project was evaluated for increasing generation transfer amounts to determine different voltage collapse points of the transmission system. Source and sink generation was scaled on a pro-rata basis to reach the pre-contingency maximum power transfer limit, or the voltage stability limit (VSL).

5.1.4.1.2 SUMMARY

Table 5.1 shows a summary of the transfer study limits by project. The table includes the project, transfer levels, the percentage of voltage violations from the year 10 model that were solved, conceptual cost, the F1 and F2 40-year APC benefit, and whether thermal overloads occur prior to voltage collapse.

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2033 Generic Winter Weather (Uri)							
Project	**Transfer (GW)**	**Transfer increase (GW)**	**% Voltage Violations Mitigated in the transfer area**	**Conceptual Cost**	**F1: 40 Year APC benefit**	**F2: 40 Year APC benefit**	**Thermal Overloads Prior to Voltage Collapse**
Base Case	2.98	NA	NA	NA	NA	NA	Yes
Tobias to Elm Creek 345 kV New Line	3.88	.90	92%	$285,528,922	$28,988,654	-$117,081,819	Yes
Tobias to Elm Creek + 200 MVAR SVC at Mingo	4.03	1.05	92%	$304,321,557	$28,988,654	-$117,081,819	Yes
Sidney to Holcomb 345 kV New Line	3.63	.65	78%	$494,937,438	$1,271,397,494	None	Yes
Sidney to Holcomb + 200 MVAR SVC at Mingo	3.78	.80	97%	$513,730,073	$1,271,397,494	$1,074,311,375	Yes
Tobias to Elm Creek + Sidney to Holcomb 345 kV New Lines	4.48	1.50	98%	$780,466,360	$3,525,010,894	$5,388,513,747	Yes
Tobias to Elm Creek + Sidney to Holcomb+ 200 MVAR SVC at Mingo	4.63	1.65	98%	$799,258,995	$1,334,809,954	$745,221,878	Yes

Table 5.1: Transfer Study Limits Summary by Project

Figure 5.3 and Figure 5.4 show the recommended projects.

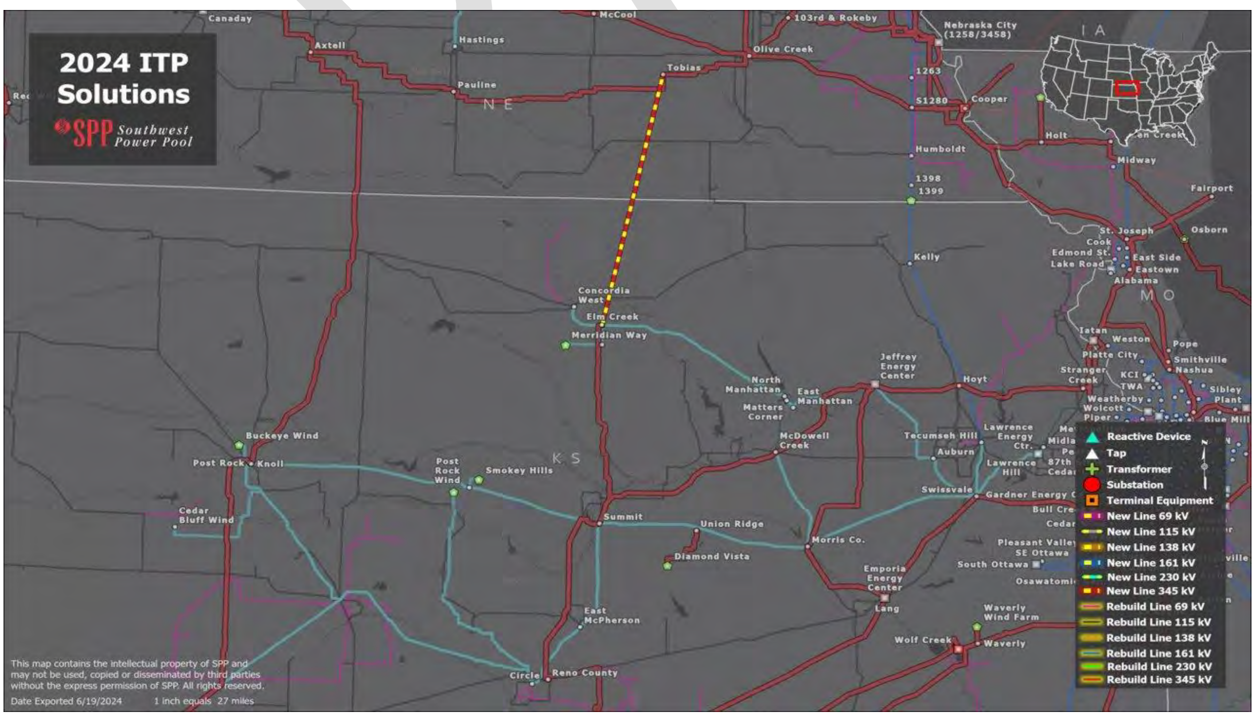

Figure 5.3: Tobias to Elm Creek 345 kV

Figure 5.4: Sidney to Holcomb 345 kV

5.1.4.1.3 CONCLUSION

The analysis demonstrates the transfer benefit for each project in the year 10 generic winter weather models. Of the evaluated projects, the best performing project group was a new 345 kV line from Tobias to Elm Creek and a new 345 kV line from Sidney to Holcomb as well as a new 200 MVAR SVC at Mingo. This project grouping provides an additional 1.65 gigawatts of transfer capability from SPP and MISO north of Kansas to SPP south of Nebraska.

Additionally, a load shed analysis was conducted on the winter weather model. The purpose of this was to determine the amount of load shed that could be reduced by the final portfolio. Two types of analysis were used: a Security Constrained Redispatch (SCRD) which sheds load based on thermal overloads, and cascading, which sheds load based on voltage levels at each monitored bus. Each of these methods show approximately a 950 MW decrease in load shed in the year 10 model.

5.1.5 OTHER SOLUTION SCREENINGS

SPP analyzed the submitted short circuit solutions to ensure that the updated fault-interrupting equipment ratings were greater than the maximum fault current identified in the needs assessment. SPP identified no public policy needs in the 2024 ITP. Therefore, no solutions were screened to address public policy needs.

5.2 PORTFOLIO DEVELOPMENT PROCESS

The purpose of the portfolio development process is to develop a consolidated list of projects that comprehensively address the system's needs. Figure 5.5 shows a high-level overview of the portfolio

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development process. The process starts with the utilization of project metrics in project grouping and continues through the development of a consolidated portfolio.

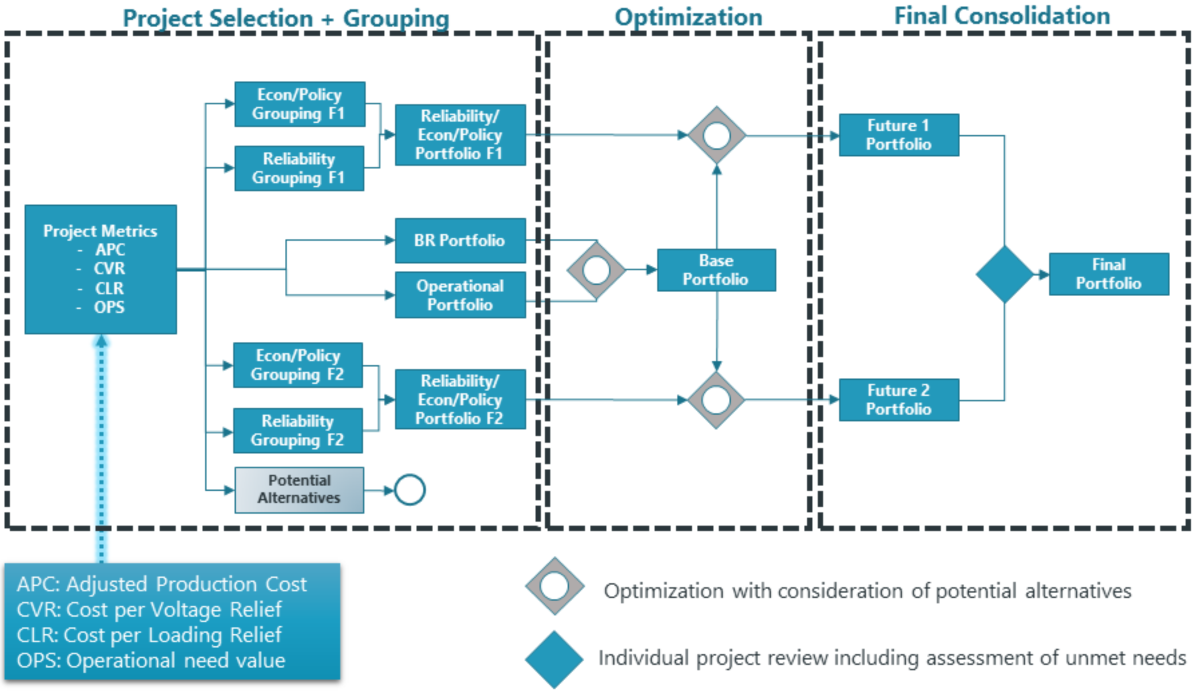

Figure 5.5: Portfolio Development Process

5.3 PROJECT SELECTION AND GROUPING

After screening all solutions, SPP drafted reliability, winter weather, operational, economic and short circuit groupings in parallel to address the different need types across the system. SPP used SCEs and stakeholder feedback from direct discussions with stakeholders, regularly scheduled working group meetings, the June 2024 SPP transmission planning summit, and SPP's Request Management System.

5.3.1 STUDY COST ESTIMATES

SPP evaluated the solutions that performed well using the screening assessments in the Solution Development and Evaluation milestone to determine if they were potentially competitive. SPP sent these solutions to TOs and a third-party estimator for the development of study cost within ±30% of the final project cost. SPP sent solutions that were not potentially competitive to the incumbent TO(s) for the development of Study Cost Estimates (SCE).[33] SPP sent solutions that were potentially competitive to a third party to develop an SCE. Once SPP received the SCEs back, SPP used them for the remainder of the portfolio development process. In cases where SPP did not receive a SCE from the incumbent TO, SPP used the previously calculated conceptual cost estimates (CCE).

[33] SPP OATT Business Practices , Section 8

5.3.2 RELIABILITY GROUPING

SPP used a programmatic method to generate a subset of solutions that addressed the reliability needs on the system. Solution selection software allowed SPP to systematically compare the performance of each solution using the metrics described in section 5.1. During this process, SPP applied engineering judgment to develop a draft list of high-performing solutions to address reliability needs.

Some areas required a more in-depth analysis of solutions to address needs. Specifically, the unprecedented load growth in North Dakota and southeast New Mexico required a holistic approach to developing the reliability grouping. SPP looked ahead to the 2025 ITP load forecast which showed continued load growth over the next 10 years in the areas. This suggested that SPP needed to plan robust solutions to get ahead of the coming load and prepare for the grid of the future. Additional information on the selected projects is given in the Project Recommendations section 6.

SPP continually refined the list of reliability solutions by incorporating stakeholder feedback and analysis results. Figure 5.6 below shows the final reliability grouping selected to address the reliability needs in the 2024 ITP.

Project	Area	Cost
15th Ave - Watertown 115 kV Rebuild	MRES/WAPA	$2,158,980
Ainsworth - Bassett 115 kV Ckt 1 New Line	NPPD	$25,100,000
Aurora - Central City 115 kV Ckt 1 New Line	NPPD	$13,700,000
Belfield 345/230 kV Transformer Ckt 2	WAPA	$17,050,000
Bismarck - Bismarck Expressway 115 kV Rebuild	WAPA	$1,209,664
Brown - Colbert 138 kV Terminal Equipment	OGE	$851,006
Channing 230 kV Capacitor	SPS	$4,467,052
Colbert 138 kV Capacitor	WFEC	$351,600
Dawson County - Lewis and Clark 115 kV Terminal Equipment	WAPA	$1,360,333
Dawson County - Williston 230 kV Ckt 1 New Line	WAPA	$157,802,000
Denver - Mid America 69 kV San Andreas - Seminole 115 kV Tap Intersection	SPS	$11,115,323
Finstad – Logan 345 kV new line, Logan - Leland Olds 345 kV Voltage Conversion	WAPA	$313,662,135
Finstad - Satterwaite 115 kV New Line	WAPA	$19,838,462
Frankford - Quaker 115 kV Rebuild	SPS	$2,753,972
Grapevine - Kingsmill 115 kV New Line	SPS	$14,337,209

Project	Area	Cost
Hanson County 115 kV System Reconfiguration	WAPA	$37,998,235
Iron House - Texaco 115 kV Ckt 1 New Line	SPS	$5,703,176
Kingsbury County 115kV Voltage Conversion	WAPA	$84,007,000
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild	WERE	$3,633,222
Logan - Magic City 230 kV Ckt 1 New Line	XEL/BEPC	$21,400,000
Lubbock East - Lubbock South 115 kV Terminal Equipment	SPS	$956,448
Lynch - Medanos 115 kV Ckt 1 New Line	SPS	$50,631,694
Madison South Dakota Area 115 kV System Reconfiguration	WAPA	$61,216,444
Marion South Dakota Area 115 kV Voltage Conversion	WAPA	$67,814,174
Moore County - XIT 230 kV Ckt 1 New Line	SPS	$52,830,105
Patent Gate - Pioneer 345 kV Ckt 1 New Line	WAPA	$163,714,033
Phantom - Crossroads - Potter 765 kV Ckt 1 New Line, Two Crossroads 765 kV Reactors	SPS	$1,690,874,827
Roadrunner 345/115 kV Ckt 2 Transformer	SPS	$19,997,839
Roadrunner 345/115 kV Ckt 3 Transformer	SPS	$19,997,839
Robinson Lake - Crane Creek 115 kV New Line	WAPA	$16,392,700
Sanderson - Pioneer 115 kV Ckt 1 New Line	WAPA	$15,299,934
Simpson - Ellisville 115 kV New Line, Zahl 115 kV Capacitor	WAPA	$18,488,763
Sioux Falls South Dakota Area 115 kV System Reconfiguration	WAPA	$25,374,827
Spring Brook - Twelve Mile 345 kV Ckt 1 New Line	WAPA	$81,116,918
Sub 1209 - Sub 1250 161 kV Rebuild	OPPD	$28,366,729
Sub 1209 - Sub 1358 161 kV Rebuild	OPPD	$1,661,726
Sub 1250 - Sub 1358 161 kV Rebuild	OPPD	$1,813,726
W Banks 345/115 kV Transformer	WAPA	$50,776,906
Wisdom 161/69 kV Transformer	WAPA	$7,641,150
	Total:	**$2,688,977,387**

Table 5.2: Reliability Project Grouping

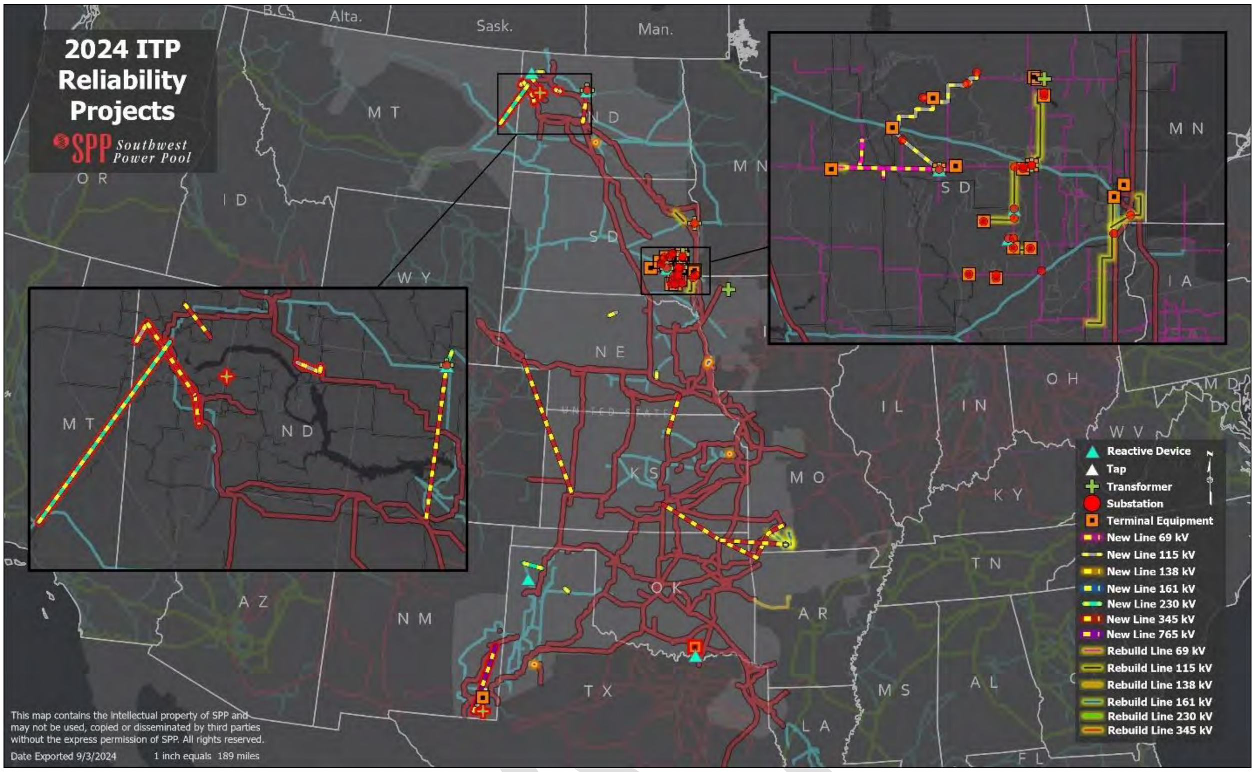

Figure 5.6: Reliability Project Grouping

5.3.3 ECONOMIC GROUPING

SPP used an iterative process to develop economic groupings. During the initial project screening phase, SPP evaluated each project to determine if it had a one-year B/C ratio of at least 0.5 or a 40-year PV B/C ratio of at least 1.0. If a project met either of the criteria, it was further evaluated and added to the applicable grouping based on one-year project cost, one-year APC benefit, 40-year project cost, 40-year PV B/C ratio, and congestion relief for the economic needs.

SPP developed three economic project groupings for each future, resulting in six total groupings:

1. Cost-Effective (CE): Projects with the lowest cost per congestion relief for a single economic need
2. Highest Net APC Benefit (HN): Projects with the highest APC benefit minus project cost, with consideration of overlap if multiple projects mitigate congestion on the same economic needs
3. Multi-variable (MV): Projects selected using data from the two other groupings; including the flexibility to use additional considerations, such as overlap with other portfolios, seams optimization and increasing energy equity across the SPP footprint

Table 5.3 identifies a comprehensive list of economic projects included in the four initial groupings. Some projects appeared in multiple groupings. The multi-variable grouping was developed later based on the results of the initial cost-effective and highest-net simulations.

Description	Future 1		Future 2	
	CE	HN	CE	HN
59th - Gill 138 kV Rebuild	X		X	
59th St - El Paso West 138 kV Terminal Equipment	X		X	
Alliance - Box Butte 115 kV Ckt 1 Rebuild	X	X	X	X
Alliance - Snake Creek 115 kV Rebuild	X	X	X	X
Alliance - Snake Creek 115 kV Terminal Upgrade	X	X	X	X
Aurora - Reeds Spring 161 kV Rebuild	X		X	
Aurora - White 115 kV Ckt 1 New Line	X		X	
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	X		X	
Bismarck - Bismarck Expressway 115 kV Rebuild	X	X	X	X
Branson North - Branson Northwest 161 kV Rebuild	X		X	
Branson North - Ozark Dam 161 kV Rebuild	X	X	X	X
Branson Northwest - Reeds Spring 161 kV Rebuild	X		X	
Brown - Colbert 138 kV Rebuild	X	X	X	X
Bull Shoals - Midway Jordan 161 kV Rebuild		X		X
Butler - Midian 138 kV Rebuild	X		X	X
Butler South - Tallgrass 138 kV Rebuild	X	X	X	X
Catoosa 161/138 kV Transformer	X	X	X	X
Centennial - Waco South 138 kV Rebuild			X	
Chisholm - Maize- Evans Energy Center North 138 kV Ckt 1 Rebuild	X		X	
Cleo Corner - Okeene 138 kV Ckt 1 New Line		X		X
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps		X		X
Dawson County - Richland- Lewis and Clark 115 kV Ckt 1 Rebuild	X		X	
Dawson County - Williston 230 kV Ckt 1 New Line		X		X
Denver City - Higgs East 115 kV New Line	X	X	X	X
Dickinson - New England - Centipede - Hettinger 115 kV Ckt 1 Rebuild		X	X	X
Evans Energy Center North- Maize 138 kV Rebuild		X		X
Fairview - Richland 115 kV Rebuild			X	
Farber - Sumner County No. 10 Belle Plain 138 kV Rebuild	X	X	X	X
Finstad - Satterwaite 115 kV New Line	X	X	X	X
Fort Randall - Spencer 115 kV Rebuild			X	
Frankford - Quaker 115 kV Rebuild	X	X	X	X
Gering - Scotts Bluff 115 kV Ckt 1 Rebuild	X	X	X	X
Gering Tap - Morrill 115 kV Ckt 1 Rebuild	X	X	X	X
Halstead - Evans Energy Center North 138 kV Ckt 1 New Line			X	
Hettinger 230/115 kV Transformer Ckt 2 (115 kV)		X	X	X
Hoskins - Stanton North 115 kV Rebuild	X	X	X	X

Description	Future 1		Future 2	
	CE	HN	CE	HN
Lamar 161/69 kV Ckt 2 Transformer		X		X
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild		X		X
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Terminal Equipment	X		X	
Logan - Magic City 230 kV Ckt 1 New Line	X		X	
Lynch - Pearl Sub 115 kV Rebuild	X	X	X	X
Magic City - Souris 115 kV Ckt 1 Rebuild		X		
Martin City (East) - Martin City (West) 161 kV Terminal Equipment	X	X	X	X
Maud Tap 138 kV Terminal Upgrade	X	X	X	X
Morrill - Snake Creek 115 kV Ckt 1 Rebuild	X	X	X	X
N Reeds Spring - S Reeds Spring 161 kV Rebuild	X	X	X	X
Pine and Peoria - Tulsa North 138 kV Terminal Upgrade	X	X	X	X
Reed Springs -North Branson - Northwest Branson - Branson North 161 kV Rebuild		X		X
Robinson Lake - Crane Creek 115 kV New Line	X	X	X	X
Sanderson - Pioneer 115 kV Ckt 1 New Line	X	X	X	X
Sub 1209 - Sub 1250 161 kV Rebuild	X	X	X	X
Tallgrass - Weaver 138 kV Rebuild	X	X	X	X
Tulsa North - CDC East 138 kV Rebuild	X	X	X	X

Table 5.3: Initial Economic Project Groupings

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5.3.3.1 *PROJECT SUBTRACTION EVALUATION*

SPP developed draft groupings using individual project screening results, which tested projects by incrementally adding projects to the base market economic models. When assessing a grouping of economic solutions, it was necessary to re-evaluate project performance within the grouping to ensure the projected APC benefit of each project in the grouping meets the required B/C ratio thresholds. SPP used subtraction evaluation to identify when multiple projects were providing congestion relief to a constraint. Subtraction analysis also showed which projects are dependent on each other to relieve overall system congestion. SPP created a new sets of base case models per grouping by adding each grouping's projects, relevant model adjustments and model corrections. SPP then removed all economic projects from the models individually to determine each project's APC impact compared to the new base case. SPP removed projects that did not meet a 1.0 B/C ratio from the subtraction evaluation from the grouping. SPP repeated this subtraction evaluation process for each grouping until all remaining projects maintained a minimum B/C ratio of 1.0 over 40 years.

5.3.3.2 *FINAL ECONOMIC GROUPINGS*

The multi-variable portfolio proved to be most advantageous in the 2024 ITP. SPP developed the multi-variable portfolio by:

APC Benefit

Using the projects identified in the highest net APC benefit as a base

Reliability

Adding projects from the reliability portfolio that had a sizable impact on system flows and provided economic benefits

Resiliency

Including projects that boost voltage support and reduce load shed observed during the recent winter storms.

Optimizing Seams

Optimizing connections along SPP seams by selecting two EHV ties that enable imports and exports to reduce the overall cost to SPP load

Energy Equity

Increasing energy equity by expanding EHV footprint to areas designated by the Department of Energy (DOE) as National Interest Electric Transmission Corridors (NIETC)

Table 5.4 identifies a comprehensive list of economic projects included in the six final economic groupings. Some projects appeared in multiple groupings.

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Alliance - Snake Creek 115 kV Rebuild	X	X	X	X	X	X
Alliance - Snake Creek 115 kV Terminal Upgrade	X	X		X	X	
Antelope - Holt County 345 kV Ckt 1 New Line	X		X	X		X
Aurora - Reeds Spring 161 kV Rebuild	X			X		
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	X			X		
Belfield - Maurine - New Underwood - Laramie River 345 kV New Line			X			X
Bismarck - Bismarck Expressway 115 kV Rebuild	X	X	X	X	X	X
Blackberry - Neosho 345 kV Rebuild		X	X		X	X
Branson North- Ozark Dam 161 kV Ckt 1 Rebuild		X			X	
Brown - Colbert 138 kV Terminal Equipment	X	X	X	X	X	X
Buffalo Flats - Delaware 345 kV New Line		X				
Bull Shoals - Midway Jordan 161 kV Rebuild		X	X		X	X
Butler - Midian 138 kV Rebuild	X		X	X	X	X
Butler South - Tallgrass 138 kV Rebuild	X	X	X	X	X	X
Catoosa 161/138 kV Transformer	X	X	X	X	X	X
Chadron - Dunlap 115 kV Ckt 1 Rebuild			X			X

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Chisholm - Maize- Evans Energy Center North 138 kV Ckt 1 Rebuild	X			X		
Chisholm - Potter 345 kV New Line			X			X
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps		X			X	
Dawson County - Williston 230 kV Ckt 1 New Line		X	X		X	X
Delaware - Monett 345 kV Ckt 1 New Line		X			X	
Maud Tap 138 kV Terminal Upgrade	X	X	X	X	X	
Farber - Sumner County No. 10 Belle Plain 138 kV Rebuild	X	X	X	X	X	X
Finstad - Satterwaite 115 kV New Line	X	X	X	X	X	X
Frankford - Quaker 115 kV Rebuild	X	X	X	X	X	X
Gering - Scotts Bluff 115 kV Ckt 1 Rebuild	X	X	X	X	X	X
Gering Tap - Morrill 115 kV Ckt 1 Rebuild	X	X	X	X	X	X
Halstead - Evans Energy Center North 138 kV Ckt 1 New Line			X	X		X
Hoskins - Stanton North 115 kV Rebuild	X	X	X	X	X	X
Lamar 161/69 kV Ckt 2 Transformer		X	X		X	X
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild		X	X		X	X
Logan - Magic City 230 kV Ckt 1 New Line	X			X		
Martin City (East) - Martin City (West) 161 kV Terminal Equipment	X	X	X	X	X	X
Monett - North Branson 345 kV Ckt 1 New Line		X			X	
Morrill - Snake Creek 115 kV Ckt 1 Rebuild	X	X	X	X	X	X
N Reeds Spring - S Reeds Spring 161 kV Rebuild	X	X	X	X	X	X
Nashua 345/161 kV Ckt 2 Transformer	X	X	X	X	X	X
Patent Gate - Pioneer 345 kV Ckt 1 New Line	X	X	X	X	X	X
Phantom - Crossroads - Potter 765 kV Ckt 1 New Line, Two Crossroads 765 kV Reactors			X			X
Reed Springs -North Branson - Northwest Branson - Branson North 161 kV Rebuild		X			X	
Roadrunner 345/115 kV Ckt 2 Transformer	X	X	X	X	X	X
Roadrunner 345/115 kV Ckt 3 Transformer	X	X	X	X	X	X
Robinson Lake - Crane Creek 115 kV New Line	X	X	X	X	X	X
S3458 - S3740 345 kV Ckt 2 New Line	X		X			X
Sanderson - Pioneer 115 kV Ckt 1 New Line	X	X	X	X	X	X
Sub 1209 - Sub 1250 161 kV Rebuild	X	X	X	X	X	X
Sub 1209 - Sub 1358 161 kV Rebuild	X	X	X	X	X	X
Sub 1250 - Sub 1358 161 kV Rebuild	X	X	X	X	X	X
Tallgrass - Weaver 138 kV Rebuild	X	X	X	X	X	X
Tulsa North - CDC East 138 kV Rebuild	X	X	X	X	X	X
Tulsa North 345/138 kV Ckt 2 Transformer	X	X	X	X	X	X
W Banks 345/115 kV Transformer	X	X	X	X	X	

Table 5.4: Final Economic Project Groupings

Table 5.5 shows a summary of benefits, costs, net APC benefit and B/C ratios. Based on the net APC benefits detailed below, SPP selected the multi-variable grouping in each future as the future's final portfolio. The multi-variable portfolio had the highest net APC benefit in Future 1. Even though it did not have the highest net APC in Future 2, SPP staff chose the multi-variable portfolio because of its synergies with other portfolio groupings, such as reliability and winter weather.

Grouping	Y5 Benefit (2024$)	Y10 Benefit (2024$)	E&C Study Cost (2024$)	40-Year PV Benefit (2024$)	40-Year PV Cost (2024$)	40 Year Net Benefit (2024$)	Y5 B/C	Y10 B/C	40-Year B/C	Selected Portfolio
F1 CE	$2.7 B	$4.5 B	$1.0 B	$79.3 B	$1.4 B	$77.9 B	18.93	31.44	56.96	
F1 HN	$2.8 B	$4.6 B	$2.4 B	$79. 6 B	$3.4 B	$76.2 B	7.94	13.05	23.59	
F1 MV	$3.8 B	$5.2 B	$4.6 B	$86.8 B	$6.4 B	**$80.4 B**	5.65	7.75	13.53	**X**
F2 CE	$2.9 B	$4.9 B	$1.0 B	$85.3 B	$1.4 B	$83.9 B	20.1	33.4	60.6	
F2 HN	$3.0 B	$4.8 B	$1.8 B	$84.1 B	$2.6 B	$81.6 B	11.3	18.3	33.0	
F2 MV	$3.9 B	$4.4 B	$4.4 B	$71.7 B	$6.2 B	**$65.5 B**	6.1	6.9	11.5	**X**

Table 5.5: Final Groupings-Benefit Cost, Net Benefits and B/C Ratios

Figure 5.7 shows the approximate location of identified projects within the SPP footprint.

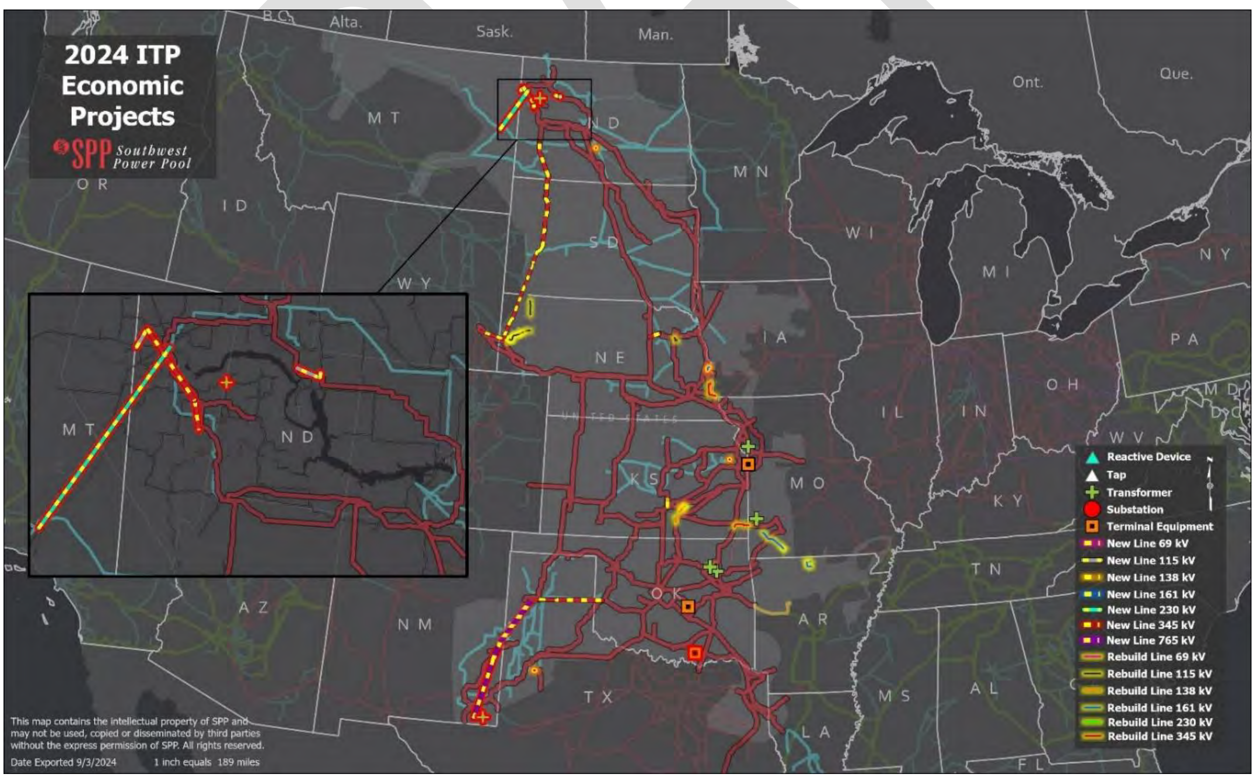

Figure 5.7: Final Economic Project Groupings

Figure 5.8 shows a 40-year B/C comparison of all the final groupings.[34]

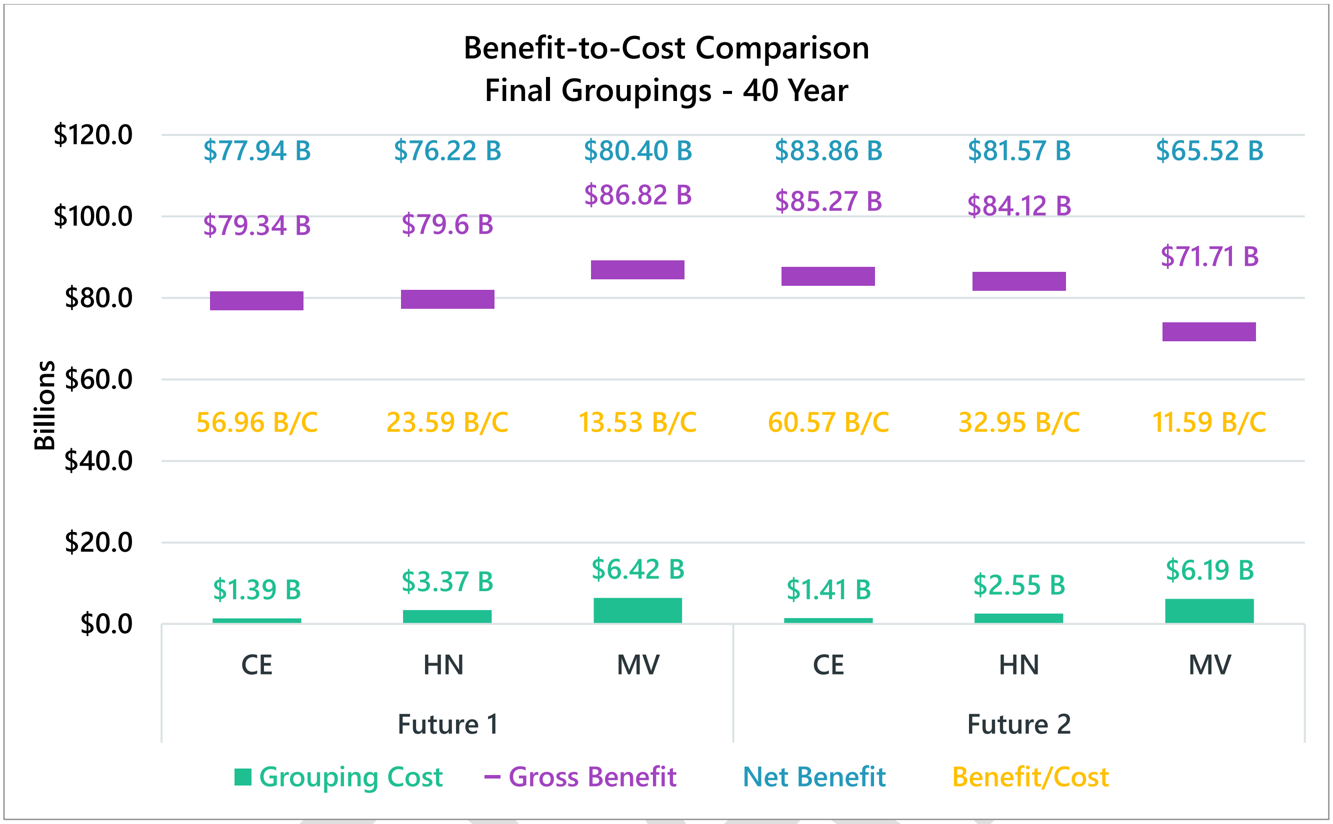

Figure 5.8: Final Groupings-Benefits and Costs Comparison

5.3.4 WINTER WEATHER GROUPING

SPP used both qualitative and quantitative approaches to develop the grouping to address needs driven by extreme winter weather. For solutions related to the target area of southwest Missouri, SPP selected a group of projects that mitigated the most voltage violations. For solutions related to increasing north to south transfer capability, SPP selected projects that offered the greatest increase in transfer capability. SPP also considered the economic benefits of the projects and groups of projects.

Table 5.6 lists the projects selected to address extreme winter weather needs.

General Description	State	Miles	Cost
Aurora - Reeds Spring 161 kV Rebuild	MO	23.7	$37,904,869
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	MO	11.5	$22,835,547
Branson North- Ozark Dam 161 kV Ckt 1 Rebuild	MO	7.1	$12,375,255
Buffalo Flats - Delaware 345 kV New Line	KS/OK	154.6	$484,090,326

[34] The 40-year costs represented in this figure are based upon the final net plant carrying charge.

General Description	State	Miles	Cost
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps	MO	2	$70,122,330
Delaware - Monett 345 kV Ckt 1 New Line	OK/MO	114.5	$342,608,905
Elm Creek - Tobias 345 kV New Line	KS/NE	85.2	$148,419,672
Holcomb - Sidney 345 kV Ckt 1 New Line	KS/NE	300	$887,460,816
Monett - North Branson 345 kV Ckt 1 New Line	MO	47.2	$165,800,962
Ozark Dam - Forsyth North - Ozark South 161 kV Voltage Conversion	MO	28.2	$38,032,729
Reed Springs - North Branson - Northwest Branson - Branson North 161 kV Rebuild	MO	9.9	$17,108,010
	Total:	**783.9**	**$2,226,759,421**

Table 5.6: Winter Weather Project Grouping

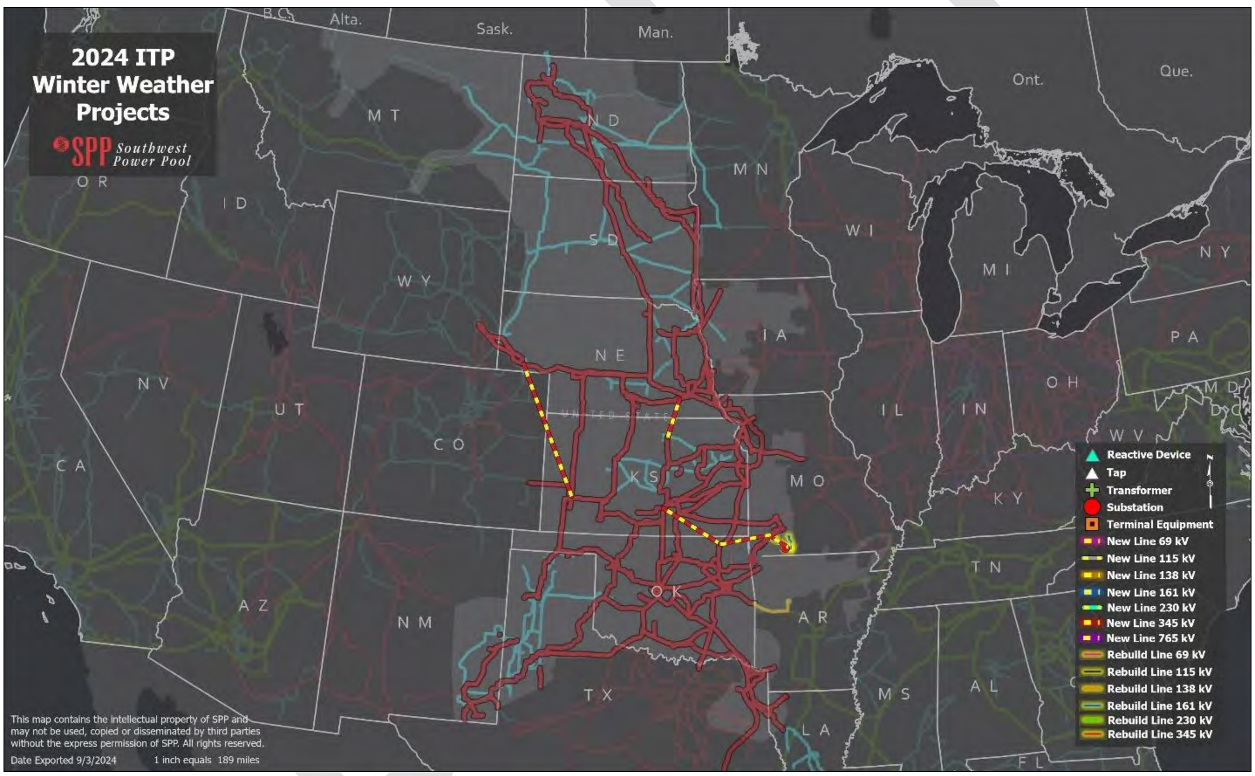

Figure 5.9: Winter Weather Project Grouping

5.3.5 SHORT-CIRCUIT GROUPING

The solutions submitted to address over-dutied fault interrupting equipment identified in the short-circuit needs assessment were grouped together to address the short-circuit needs. No testing was required for these solutions because the submitted upgrades are only required to be rated higher than the maximum fault current identified in the needs assessment. Table 5.7 summarizes the final short-circuit grouping, while Figure 5.10 shows the approximate location of identified projects within the SPP footprint.

Reliability Project	Area	Cost	Cost Source	Scenario
S1260 161 kV one breaker replacement	OPPD	$1,273,928	CCE	25S / BR
Tinker 138 kV two breaker replacements	OGE	$600,000	SCE	25S / BR
	Total	**$1,873,928**		

Table 5.7: Short-Circuit Project Grouping

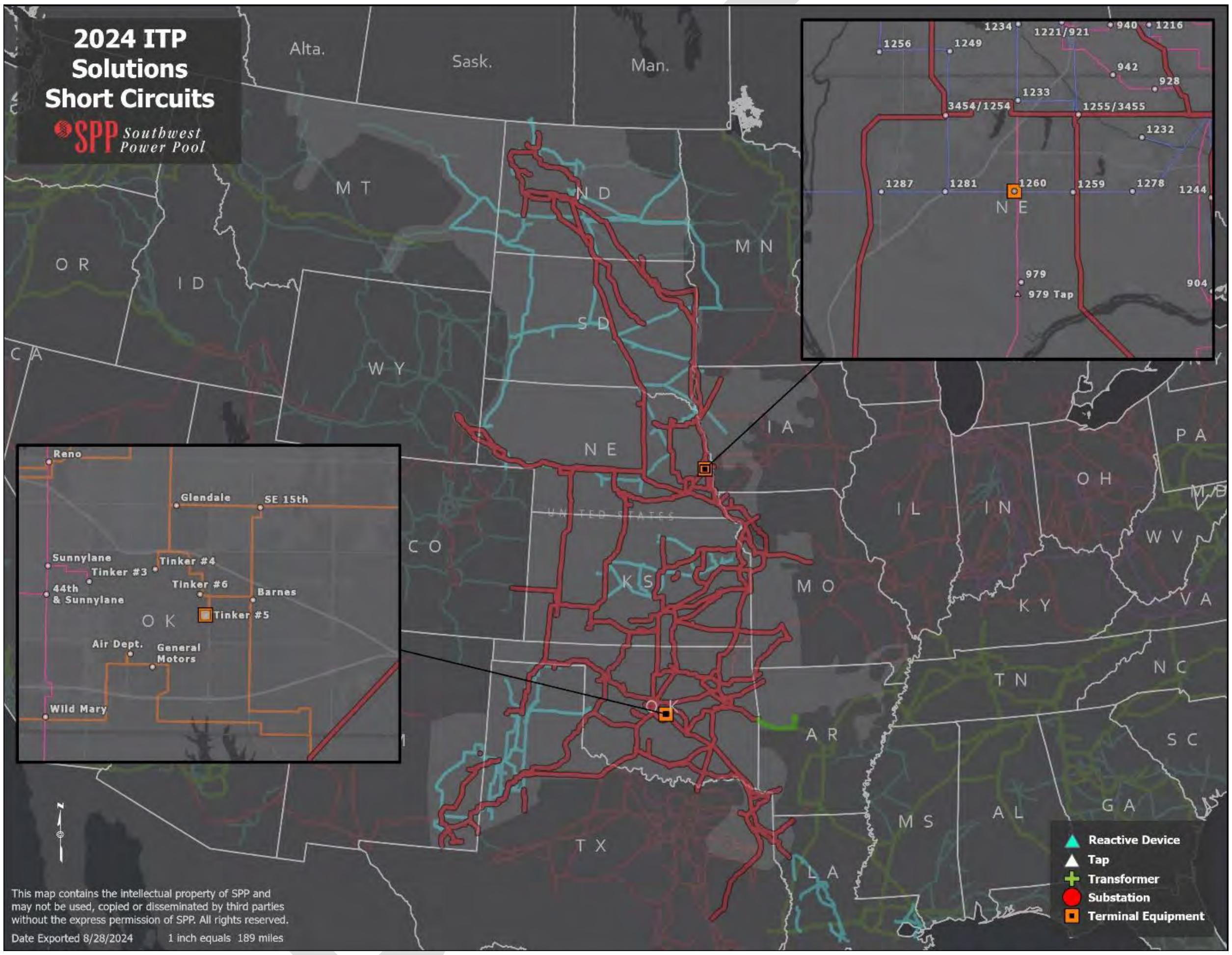

Figure 5.10: Short-Circuit Project Grouping

5.4 OPTIMIZATION

SPP selected projects for the reliability portfolio based on their ability to be cost-effective, maintain reliability, and meet the system's compliance needs. SPP selected economic projects for the economic groupings based on their ability to provide ratepayer benefits from lower-cost energy by mitigating system congestion and improving markets for both buyers and sellers. Projects were selected based on criteria specific to their need and model type. SPP evaluated the reliability portfolio to determine its impact on each economic grouping. Once SPP had developed comprehensive future specific portfolios, SPP assessed the impact of the base reliability portfolio. Due to the synergies between economic and reliability portfolios, economic portfolio optimization was deferred to the staging process. In the final optimized portfolio, the Dawson to Williston 230 kV New Line was selected over the reliability projects Dawson to Lewis 115 kV Rebuild. No additional overlap of economic and reliability projects was identified. Therefore, the remainder of reliability and economic projects were included in the final optimized portfolios.

5.5 PORTFOLIO CONSOLIDATION

To develop a single portfolio for recommendation to stakeholders, the final future-specific portfolios must be consolidated. To help guide decision-making to determine project inclusion in the single portfolio, SPP utilized a systematic scoring methodology to evaluate project performance. Under this approach, three scenarios can occur during the consolidation of the future-specific portfolios into a single portfolio:

1. The same project is addressing the same or similar needs in both futures.
2. Different projects are addressing the same or similar needs in both futures.
3. A project addresses certain needs in only one future.

Projects applicable to scenario 1 are automatically considered for inclusion in the consolidated portfolio. Projects applicable to scenarios 2 or 3 require additional assessment to determine portfolio eligibility.

To evaluate projects meeting scenario 2 or 3 conditions, SPP and its stakeholders developed a systematic scoring rubric considering both quantitative and qualitative metrics. Quantitative metrics included APC B/C ratios and the percentage of congestion relieved. Qualitative metrics include crediting projects able to address operational congestion or non-thermal issues. Table 5.8 details the scoring rubric, as well as some of the minimum criteria projects must meet to receive points.

No.	Consideration	Possible Points
1	APC net benefit and B/C ratio in selected future APC net benefit and B/C ratio in opposite future 40-year (1-year) APC net benefit in selected future ($M) 40-year (1-year) APC net benefit in opposite future ($M)	50
2	Congestion relieved in selected future (by need(s), all years)	10
	Congestion relieved in opposite future (by need(s), all years)	10
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10
4	New EHV	7.5
5	Mitigate non-thermal issues	7.5
6	Long-term viability (*e.g.*, 2013 ITP, 2022 20 Year-Assessment) or improved ARR feasibility	5
	Total Score (minimum 70 threshold)	

Table 5.8: Consolidation Considerations Scoring Table

For the 2024 ITP, stakeholders agreed the two futures would be treated equally to determine the consolidated portfolio. SPP staff included all short-circuit and reliability projects in the consolidated portfolio; therefore, consolidation considerations in this assessment applied to economic projects only. A detailed description of the consolidation methodology and scoring rubric can be found in the 2024 ITP Scope.

5.5.1 CONSOLIDATION SCENARIO ONE

Twenty-nine economic projects were included in both the Future 1 and Future 2 final portfolios and were also included in the consolidated portfolio. These projects are:

- S3458 - S3740 345 kV Ckt 2 New Line
- Farber - Sumner County No. 10 Belle Plain 138 kV Rebuild
- Martin City (East) - Martin City (West) 161 kV Terminal Equipment
- Lamar 161/69 kV Ckt 2 Transformer
- Butler - Midian 138 kV Rebuild
- Belfield - Maurine - New Underwood - Laramie River 345 kV New Line
- Bull Shoals - Midway Jordan 161 kV Rebuild
- Antelope - Holt County 345 kV Ckt 1 New Line
- Hoskins - Stanton North 115 kV Rebuild
- Buffalo Flats - Delaware 345 kV New Line
- Branson North - Ozark Dam 161 kV Ckt 1 Rebuild
- N Reeds Spring - S Reeds Spring 161 kV Rebuild
- Butler South - Tallgrass 138 kV Rebuild
- Tallgrass - Weaver 138 kV Rebuild
- Gering - Scotts Bluff 115 kV Ckt 1 Rebuild
- Morrill - Snake Creek 115 kV Ckt 1 Rebuild
- Gering Tap - Morrill 115 kV Ckt 1 Rebuild
- Alliance - Snake Creek 115 kV Rebuild
- Monett - North Branson 345 kV Ckt 1 New Line
- Delaware - Monett 345 kV Ckt 1 New Line
- Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps
- Catoosa 161/138 kV Transformer
- Chadron - Dunlap 115 kV Ckt 1 Rebuild
- Blackberry - Neosho 345 kV Rebuild
- Chisholm - Potter 345 kV New Line
- Halstead - Evans Energy Center North 138 kV Ckt 1 New Line
- Reed Springs -North Branson - Northwest Branson - Branson North 161 kV Rebuild
- Tulsa North 345/138 kV Ckt 2 Transformer
- Tulsa North - CDC East 138 kV Rebuild

5.5.2 CONSOLIDATION SCENARIO TWO

For two projects applicable to scenario two, the project achieving the higher score will be considered favorable for consolidation. Scoring parameters are detailed in Table 5.8.

In the 2024 ITP, no projects met the criteria for consolidation under scenario two.

5.5.3 CONSOLIDATION SCENARIO THREE

Projects applicable to scenario three must achieve a minimum score of 70 points to be considered by SPP for consolidation. Scoring parameters are detailed in Table 5.8. For the 2024 ITP, seven projects were assessed under scenario three scoring conditions. Only one project met the minimum score requirement for inclusion in the final consolidated portfolio.

5.5.3.1 *Axtell 345/115 kV Transformer Ckt 2*

The Axtell 345/115 kV Transformer Ckt 2 originated from the Future 1 portfolio. The project performed well in the congestion-relieved metrics, but it did not meet the B/C ratio criteria, resulting in a zero score for both net benefit and B/C ratio criteria. Consequently, the project did not meet the minimum scoring threshold for inclusion in the consolidated portfolio.

<table>
<tr><th>No.</th><th>Consideration</th><th>Possible Points</th><th>Project Score</th></tr>
<tr><td rowspan="2">1</td><td>APC net benefit and B/C ratio in selected future</td><td rowspan="2">50</td><td rowspan="2">0</td></tr>
<tr><td>APC net benefit and B/C ratio in opposite future</td></tr>
<tr><td rowspan="2">2</td><td>Congestion relieved in selected future (by need(s), all years)</td><td>10</td><td rowspan="2">20</td></tr>
<tr><td>Congestion relieved in opposite future (by need(s), all years)</td><td>10</td></tr>
<tr><td>3</td><td>Operational congestion costs or reconfiguration ($M/yr or hrs/yr)</td><td>10</td><td>0</td></tr>
<tr><td>4</td><td>New EHV</td><td>7.5</td><td>0</td></tr>
<tr><td>5</td><td>Mitigate non-thermal issues</td><td>7.5</td><td>0</td></tr>
<tr><td>6</td><td>Long-term viability (e.g., 2013 ITP, 2022 20 Year-Assessment) or improved ARR feasibility</td><td>5</td><td>0</td></tr>
<tr><td colspan="3">Total Score (minimum 70 threshold)</td><td>20</td></tr>
</table>

Table 5.9: Axtell 345/115 kV Transformer Ckt 2 Consolidation Scoring

5.5.3.2 *Cleo Corner - Okeene 138 kV Ckt 1 New Line*

The Cleo Corner - Okeene 138 kV Ckt 1 New Line originated from the Future 1 portfolio. The project performed well in the congestion-relieved metrics, but it did not meet the B/C ratio criteria, resulting in a zero score for both net benefit and B/C ratio criteria. Consequently, the project did not meet the minimum scoring threshold for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	0
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP, 2022 20 Year-Assessment) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**20**

Table 5.10: Cleo Corner - Okeene 138 kV Ckt 1 New Line Consolidation Scoring

5.5.3.3 *Maize - Evans Energy Center North 138 kV Ckt 1 Rebuild*

The Maize - Evans Energy Center North 138 kV Ckt 1 Rebuild originated from the Future 1 portfolio. The Project performed well in the net benefit and B/C ratio, as well in the congestion-relieved criteria. Therefore, the project was included in the final portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	20
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP, 2022 20 Year-Assessment) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**70**

Table 5.11: Maize - Evans Energy Center North 138 kV Ckt 1 Rebuild Consolidation Scoring

5.5.3.4 *Magic City - Souris 115 kV Ckt 1 Rebuild*

The Magic City - Souris 115 kV Ckt 1 Rebuild originated from the Future 1 portfolio. The project performed well using the net benefit and B/C ratio. However, it did not perform well enough with the other considerations to meet the minimum scoring threshold.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	0
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP, 2022 20 Year-Assessment) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**50**

Table 5.12: Magic City - Souris 115 kV Ckt 1 Rebuild Consolidation Scoring

5.5.3.5 *Belfield 345/230 kV Transformer Ckt 1 & 2*

The Belfield 345/230 kV Transformer Ckt 1 & 2 originated from the Future 1 portfolio. The project performed well using the net benefit and B/C ratio. However, it did not perform well enough with the other considerations to meet the minimum scoring threshold.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future	50	50
	APC net benefit and B/C ratio in opposite future		
2	Congestion relieved in selected future (by need(s), all years)	10	0
	Congestion relieved in opposite future (by need(s), all years)	10	
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP, 2022 20 Year-Assessment) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**50**

Table 5.13: Belfield 345/230 kV Transformer Ckt 1 & Ckt 2 Consolidation Scoring

5.5.3.6 *Hettinger 345/115 kV Transformer Ckt 2*

The Hettinger 345/115 kV Transformer Ckt 2 originated from the Future 1 portfolio. The project performed well using the net benefit, and B/C ratio. However, it did not perform well enough with the other considerations to meet the minimum scoring threshold.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future APC net benefit and B/C ratio in opposite future	50	50
2	Congestion relieved in selected future (by need(s), all years) Congestion relieved in opposite future (by need(s), all years)	10 10	0
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP, 2022 20 Year-Assessment) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**50**

Table 5.14: Hettinger 345/115 kV Transformer Ckt 2 Consolidation Scoring

5.5.3.7 *Oakland - West Point - Beemer - Stanton - Stanton North 115 kV Ckt 1 Rebuild*

The Oakland - West Point - Beemer - Stanton - Stanton North 115 kV Ckt 1 Rebuild originated from the Future 1 portfolio. Although it performed well in congestion-relieved criteria, it did not meet the B/C ratio criteria, resulting in a zero score for both net benefit and B/C ratio criteria. Consequently, the project did not meet the minimum scoring threshold for inclusion in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	APC net benefit and B/C ratio in selected future APC net benefit and B/C ratio in opposite future	50	0
2	Congestion relieved in selected future (by need(s), all years) Congestion relieved in opposite future (by need(s), all years)	10 10	20
3	Operational congestion costs or reconfiguration ($M/yr or hrs/yr)	10	0
4	New EHV	7.5	0
5	Mitigate non-thermal issues	7.5	0
6	Long-term viability (*e.g.*, 2013 ITP, 2022 20 Year-Assessment) or improved ARR feasibility	5	0
		Total Score (minimum 70 threshold)	**20**

Table 5.15: Oakland - West Point - Beemer - Stanton - Stanton North 115 kV Ckt 1 Rebuild Consolidation Scoring

5.6 FINAL CONSOLIDATED PORTFOLIO

The consolidated portfolio includes the reliability projects addressing both steady state and short-circuit needs, as well as the consolidated set of economic projects that met the consolidation criteria. The consolidated portfolio totals $7.01 billion and is projected to create $87.48 billion to $94.13 billion in APC savings under Future 1 or Future 2 assumptions, respectively. Table 5.16 lists the projects included in the final consolidated portfolio along with their classifications and costs. Benefit data reported in this section includes only APC savings.

Description	Classification	Area	Project Cost (2024$)
15th Ave - Watertown 115 kV Rebuild	R	MRES/WAPA	$2,158,980
Ainsworth - Bassett 115 kV Ckt 1 New Line	R	NPPD	$25,100,000
Alliance - Snake Creek 115 kV Rebuild	E	WAPA-RMR	$12,055,000
Alliance - Snake Creek 115 kV Terminal Upgrade	O	WAPA-RMR	$770,666
Antelope - Holt County 345 kV Ckt 1 New Line	E	NPPD	$67,100,000
Aurora - Central City 115 kV Ckt 1 New Line	R	NPPD	$13,700,000
Aurora - Reeds Spring 161 kV Rebuild	WW	EMDE	$37,904,869
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	O/WW	EMDE	$22,835,547
Belfield - Maurine - New Underwood - Laramie River 345 kV New Line	E	BEPC/WAPA	$1,114,609,566
Bismarck - East Bismarck 115 kV Rebuild	E/R	WAPA/CPEC	$1,209,664
Blackberry - Neosho 345 kV Rebuild	E	KAMO/WERE	$46,612,099
Branson North - Branson Northwest -North Branson - Reed Springs 161 kV Rebuild	WW	EMDE	$16,704,792
Branson North - Ozark Dam 161 kV Ckt 1 Rebuild	WW	EMDE	$12,375,255
Brown - Colbert 138 kV Terminal Equipment	E/R	OGE/SWPA	$851,006
Buffalo Flats - Delaware 345 kV New Line	WW	AEP	$484,090,326
Bull Shoals - Midway Jordan 161 kV Rebuild	E	SWPA/EEA	$12,785,321
Butler - Midian 138 kV Rebuild	E	WERE	$10,906,736
Butler South - Tallgrass 138 kV Rebuild	E	WERE	$19,571,986
Catoosa 161/138 kV Transformer	E	GRDA/AEP	$7,641,150
CDC East - Tulsa North 138 kV Rebuild	E	AEP	$5,804,960
Chadron - Dunlap 115 kV Ckt 1 Rebuild	E	NPPD/WAPA-RMR	$19,314,577
Channing 230 kV Capacitor	R	SPS	$4,467,052
Chisholm - Maize - Evans Energy Center North 138 kV Ckt 1 Rebuild	E	WERE	$22,687,706
Chisholm - Potter 345 kV New Line	E	AEPW/SPS	$442,665,905
Colbert 138 kV Capacitor	R	WFEC	$351,600
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps	WW	KAMO (AECI)/ EMDE/SWPA	$70,122,330
Conway - Kirby 115 kV Terminal Upgrade	O	SPS	$770,666

Description	Classification	Area	Project Cost (2024$)
Crane Creek - Robinson Lake 115 kV New Line	E/R	BEPC	$16,392,701
Dawson County - Williston 230 kV Ckt 1 New Line	R	WAPA	$157,802,000
Delaware - Monett 345 kV Ckt 1 New Line	WW	AEP/EMDE	$342,608,905
Denver - Mid America 69 kV San Andreas - Seminole 115 kV Tap Intersection	R	SPS	$11,115,323
Edwardsville 161/115 kV Transformer	O	WERE	$6,345,206
Ellisville - Simpson 115 kV New Line, Zahl 115 kV Capacitor	R	MWEC	$18,488,763
Elm Creek - Tobias 345 kV New Line	WW	ITC GP/NPPD	$148,419,672
Evans Energy Center North - Halstead 138 kV Ckt 1 New Line	E	WERE	$39,683,130
Farber - Sumner County No. 10 Belle Plain 138 kV Rebuild	E	WERE	$21,841,037
Finstad - Logan 345 kV New Line, Leland Olds - Logan 345 kV Voltage Conversion	R	BEPC	$313,662,135
Finstad - Satterwaite 115 kV New Line	E/R	MWEC	$19,838,462
Frankford - Quaker 115 kV Rebuild	R	SPS	$2,753,972
Gering Tap - Morrill 115 kV Ckt 1 Rebuild	E	WAPA-RMR	$24,272,842
Gering Tap - Scotts Bluff 115 kV Ckt 1 Rebuild	E	NPPD/ WAPA-RMR	$3,385,333
Grapevine - Kingsmill 115 kV New Line	R	SPS	$14,337,209
Hanson County 115 kV System Reconfiguration	R	EREC	$37,998,235
Holcomb - Sidney 345 kV Ckt 1 New Line	O/WW	BEPC/SUNC	$887,460,816
Hoskins - Stanton North 115 kV Rebuild	E	NPPD	$4,000,000
Iron House - Texaco 115 kV Ckt 1 New Line	R	LE-REC/SPS	$5,703,176
Kingsbury County 115kV Voltage Conversion	R	EREC	$84,007,000
Lamar 161/69 kV Ckt 2 Transformer	E	AECI	$7,641,150
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild	E/R	WERE	$3,633,222
Logan - Magic City 230 kV Ckt 1 New Line	R	XEL/BEPC	$21,400,000
Lynch - Medanos 115 kV Ckt 1 New Line	R	SPS	$50,631,694
Madison South Dakota Area 115 kV System Reconfiguration	R	EREC	$61,216,444
Marion South Dakota Area 115 kV Voltage Conversion	R	EREC	$67,814,174
Martin City (East) - Martin City (West) 161 kV Terminal Equipment	E	GMO	$3,060,219

Description	Classification	Area	Project Cost (2024$)
Maud Tap 138 kV Terminal Upgrade	E	AEP/OGE	$425,503
Monett - North Branson 345 kV Ckt 1 New Line	WW	EMDE	$165,800,962
Moore County - XIT 230 kV Ckt 1 New Line	R	SPS	$52,830,105
Morrill - Snake Creek 115 kV Ckt 1 Rebuild	E	WAPA-RMR	$9,596,378
N Reeds Spring - S Reeds Spring 161 kV Rebuild	WW	EMDE	$3,266,430
Nashua 345/161 kV Ckt 2 Transformer	E/O	EM	$24,750,244
Ozark Dam - Forsyth North - Ozark South 161 kV Voltage Conversion	WW	EMDE	$38,032,729
Patent Gate - Pioneer 345 kV Ckt 1 New Line	R	BEPC	$163,714,033
Phantom - Crossroads - Potter 765 kV Ckt 1 New Line	E/R	SPS	$1,690,874,827
Pioneer - Sanderson 115 kV Ckt 1 New Line	E/R	MWEC	$15,299,934
Roadrunner 345/115 kV Ckt 2 Transformer	R	SPS	$19,997,839
Roadrunner 345/115 kV Ckt 3 Transformer	R	SPS	$19,997,839
S1260 161 kV Breaker Replacement	SC	OPPD	$1,273,928
S3458 - S3740 345 kV Ckt 2 New Line	E/R	OPPD	$98,650,000
Sioux Falls South Dakota Area 115 kV System Reconfiguration	R	EREC/WAPA	$25,374,827
Spring Brook - Twelve Mile 345 kV Ckt 1 New Line	R	BEPC	$81,116,918
Sub 1209 - Sub 1250 161 kV Rebuild	R	OPPD	$28,366,729
Sub 1209 - Sub 1358 161 kV Rebuild	R	OPPD	$1,661,726
Sub 1250 - Sub 1358 161 kV Rebuild	R	OPPD	$1,813,726
Tallgrass - Weaver 138 kV Rebuild	E	EKC	$11,986,623
Tulsa North 345/138 kV Ckt 2 Transformer	E	AEP	$13,022,086
W Banks 345/115 kV Transformer	E/R	BEPC	$50,776,906
Wisdom 161/69 kV Transformer	R	WAPA	$7,641,150
		Total	$6,952,463,257

Table 5.16: Final Consolidated Portfolio

Table 5.17 provides the Future 1 and Future 2 40-year B/C ratios and net benefits for all economic projects included in the consolidated portfolio using the same process described in the Section 5.3.3.1 for project subtraction evaluation.

Project	E&C Project Cost (2024$ M)	40-Year PV Cost (2024$ M)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 40-year Benefit (2024$ M)	F1 40-year Net Benefit (2024$ M)	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C	F2 40-year Benefit (2024$ M)	F2 40-year Net Benefit (2024$ M)
Alliance - Snake Creek 115 kV Rebuild	$12.06	$16.91	7.08	2.32	1.25	$21.10	$4.20	8.08	3.53	3.31	$56.04	$39.13
Alliance - Snake Creek 115 kV Terminal Upgrade	$0.77	$1.08	2.96	(1.87)	(5.52)	($5.96)	($7.04)	2.68	11.41	22.85	$24.69	$23.61
Antelope - Holt County 345 kV Ckt 1 New Line	$67.10	$94.10	2.06	1.60	2.32	$218.61	$124.51	3.32	2.67	3.95	$371.85	$277.75
Aurora - Reeds Spring 161 kV Rebuild	$37.90	$53.16	0.03	(0.33)	(0.73)	($38.67)	($91.83)	(0.48)	0.15	0.58	$30.74	($22.41)
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	$22.84	$32.02	0.78	(0.36)	(1.16)	($37.29)	($69.32)	0.19	(0.01)	(0.12)	($3.98)	($36.01)
Belfield - Maurine - New Underwood - Laramie River 345 kV New Line	$1,114.61	$1,563.11	0.96	0.46	0.49	$765.82	($797.29)	1.11	0.71	0.92	$1,442.03	($121.08)
Bismarck - East Bismarck 115 kV Rebuild	$1.21	$1.70	98.13	10.08	(29.51)	($50.05)	($51.75)	219.31	7.38	(98.10)	($166.42)	($168.12)
Blackberry - Neosho 345 kV Rebuild	$46.61	$65.37	0.38	0.86	1.62	$106.09	$40.72	0.53	0.48	0.75	$49.14	($16.23)
Brown - Colbert 138 kV Terminal Equipment	$0.85	$1.19	0.00	96.70	205.38	$245.11	$243.92	0.00	122.05	259.21	$309.35	$308.16
Butler - Midian 138 kV Rebuild	$10.91	$15.30	2.03	1.01	1.09	$16.72	$1.43	(0.87)	2.09	4.88	$74.71	$59.41
Butler South - Tallgrass 138 kV Rebuild	$19.57	$27.45	13.70	16.49	27.90	$765.86	$738.41	14.21	21.86	39.05	$1,071.79	$1,044.34
Catoosa 161/138 kV Transformer	$7.64	$10.72	26.89	22.34	33.49	$358.91	$348.19	25.34	27.03	44.26	$474.25	$463.54
Chadron - Dunlap 115 kV Ckt 1 Rebuild	$19.31	$27.09	0.06	(0.40)	(0.88)	($23.88)	($50.96)	0.58	(1.10)	(2.64)	($71.60)	($98.68)
Chisholm - Maize- Evans Energy Center North 138 kV Ckt 1 Rebuild	$22.69	$31.82	0.24	0.00	(0.11)	($3.63)	($35.45)	0.49	(0.65)	(1.64)	($52.16)	($83.98)

Project	E&C Project Cost (2024$ M)	40-Year PV Cost (2024$ M)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 40-year Benefit (2024$ M)	F1 40-year Net Benefit (2024$ M)	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C	F2 40-year Benefit (2024$ M)	F2 40-year Net Benefit (2024$ M)
Chisholm - Potter 345 kV New Line	$442.67	$620.79	0.49	0.95	1.76	$1,092.72	$471.94	0.75	0.60	0.89	$550.09	($70.69)
Conway - Kirby 115 kV Terminal Upgrade	$0.77	$1.08	2.96	(1.87)	(5.52)	($5.96)	($7.04)	2.68	11.40	22.83	$24.68	$23.59
Dawson County - Williston 230 kV Ckt 1 New Line	$157.80	$221.30	1.86	3.31	6.06	$1,340.11	$1,118.81	1.44	3.96	7.68	$1,698.64	$1,477.34
Edwardsville 161/115 kV Transformer	$6.35	$8.90	(27.80)	(16.83)	(21.32)	($189.72)	($198.62)	(28.27)	(14.06)	(15.20)	($135.29)	($144.18)
Elm Creek - Tobias 345 kV New Line	$148.42	$208.14	0.45	0.04	(0.16)	($32.84)	($240.98)	0.10	0.13	0.23	$48.23	($159.91)
Farber - Sumner County No. 10 Belle Plain 138 kV Rebuild	$21.84	$30.63	4.55	3.16	4.35	$133.38	$102.75	3.39	3.39	5.44	$166.65	$136.02
Finstad - Satterwaite 115 kV New Line	$19.84	$27.82	1.04	569.13	1,208.20	$33,613.31	$33,585.49	1.46	668.88	1,419.84	$39,501.45	$39,473.63
Frankford - Quaker 115 kV Rebuild	$2.75	$3.86	1.63	28.83	60.38	$233.20	$229.33	4.35	23.51	47.69	$184.17	$180.31
Gering Tap - Morrill 115 kV Ckt 1 Rebuild	$24.27	$34.04	0.31	(0.26)	(0.71)	($24.01)	($58.04)	0.65	0.23	0.16	$5.34	($28.70)
Gering Tap - Scotts Bluff 115 kV Ckt 1 Rebuild	$3.39	$4.75	4.54	(2.42)	(7.50)	($35.60)	($40.35)	9.97	11.21	18.64	$88.49	$83.74
Halstead - Evans Energy Center North 138 kV Ckt 1 New Line	$39.68	$55.65	0.67	(0.01)	(0.37)	($20.68)	($76.33)	0.62	0.47	0.68	$37.98	($17.67)
Holcomb - Sidney 345 kV Ckt 1 New Line	$887.46	$1,244.56	0.15	0.04	0.02	$19.32	($1,225.24)	0.14	0.04	0.01	$13.59	($1,230.97)
Hoskins - Stanton North 115 kV Rebuild	$4.00	$5.61	3.03	8.24	15.92	$89.28	$83.68	7.60	19.39	37.23	$208.84	$203.23
Lamar 161/69 kV Ckt 2 Transformer	$7.64	$10.72	(3.91)	(6.64)	(12.08)	($129.44)	($140.15)	(2.78)	(11.89)	(23.82)	($255.26)	($265.98)
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild	$3.63	$5.10	2.94	16.20	32.88	$167.53	$162.44	8.97	15.97	29.26	$149.10	$144.01

Project	E&C Project Cost (2024$ M)	40-Year PV Cost (2024$ M)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 40-year Benefit (2024$ M)	F1 40-year Net Benefit (2024$ M)	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C	F2 40-year Benefit (2024$ M)	F2 40-year Net Benefit (2024$ M)
Martin City (East) - Martin City (West) 161 kV Terminal Equipment	$3.06	$4.29	14.77	10.45	14.54	$62.41	$58.11	2.60	3.54	6.16	$26.44	$22.14
Maud Tap 138 kV Terminal Upgrade	$0.43	$0.60	(8.36)	9.78	25.11	$14.98	$14.39	27.21	7.86	2.57	$1.54	$0.94
Morrill - Snake Creek 115 kV Ckt 1 Rebuild	$9.60	$13.46	0.79	(1.44)	(3.47)	($46.66)	($60.12)	1.11	0.98	1.51	$20.26	$6.80
Nashua 345/161 kV Ckt 2 Transformer	$24.75	$34.71	2.16	1.46	1.98	$68.59	$33.88	4.10	4.28	6.96	$241.43	$206.72
Ozark Dam - Forsyth North - Ozark South 161 kV Voltage Conversion	$38.03	$53.34	0.33	(0.10)	(0.40)	($21.07)	($74.41)	0.20	0.16	0.24	$12.55	($40.79)
Patent Gate - Pioneer 345 kV Ckt 1 New Line	$163.71	$229.59	0.90	2.75	5.38	$1,234.79	$1,005.20	1.02	5.90	12.01	$2,756.53	$2,526.94
Phantom - Crossroads - Potter 765 kV Ckt 1 New Line, Two Crossroads 765 kV Reactors	$1,266.39	$1,775.96	4.31	2.53	3.13	$5,565.88	$3,789.93	3.81	2.06	2.39	$4,244.03	$2,468.08
Roadrunner 345/115 kV Ckt 2 Transformer	$20.00	$28.04	0.31	(0.49)	(1.20)	($33.76)	($61.80)	0.42	(0.21)	(0.67)	($18.71)	($46.75)
Roadrunner 345/115 kV Ckt 3 Transformer	$20.00	$28.04	168.36	152.05	235.58	$6,606.78	$6,578.74	209.32	196.25	308.21	$8,643.54	$8,615.49
Robinson Lake - Crane Creek 115 kV New Line	$16.39	$22.99	1.61	1,057.79	2,245.74	$51,626.79	$51,603.80	1.53	1,253.85	2,662.17	$61,200.25	$61,177.26
S3458 - S3740 345 kV Ckt 2 New Line	$98.65	$138.34	1.94	0.91	0.92	$126.83	($11.52)	1.34	0.10	(0.47)	($65.67)	($204.02)
Sanderson - Pioneer 115 kV Ckt 1 New Line	$15.30	$21.46	1,081.60	1,308.40	2,217.71	$47,584.02	$47,562.57	1,156.06	1,369.31	2,308.44	$49,530.64	$49,509.19
Sub 1209 - Sub 1250 - Sub 1358 - Sub 1209 161 kV Rebuild	$31.84	$44.65	0.17	0.21	0.36	$16.27	($28.38)	0.38	0.45	0.76	$34.12	($10.53)
Tallgrass - Weaver 138 kV Rebuild	$11.99	$16.81	29.34	36.31	61.89	$1,040.31	$1,023.50	34.75	43.41	74.17	$1,246.75	$1,229.94

Project	E&C Project Cost (2024$ M)	40-Year PV Cost (2024$ M)	F1 Y5 B/C	F1 Y10 B/C	F1 40-year B/C	F1 40-year Benefit (2024$ M)	F1 40-year Net Benefit (2024$ M)	F2 Y5 B/C	F2 Y10 B/C	F2 40-year B/C	F2 40-year Benefit (2024$ M)	F2 40-year Net Benefit (2024$ M)
Tulsa North - CDC East 138 kV Rebuild	$5.80	$8.14	14.27	9.30	12.35	$100.56	$92.42	14.34	10.98	15.88	$129.30	$121.16
Tulsa North 345/138 kV Ckt 2 Transformer	$13.02	$18.26	5.65	3.59	4.70	$85.82	$67.56	2.53	2.92	4.90	$89.39	$71.13
W Banks 345/115 kV Transformer	$50.78	$71.21	0.72	1.34	2.47	$175.97	$104.76	0.49	1.44	2.81	$200.20	$128.99

Table 5.17: Consolidated Portfolio - APC benefit only[35]

[35] These project-specific APC benefits are calculated on the consolidated portfolio only, and do not include the addition of the Muskogee - Tahlequah 161 kV rebuild and Muskogee - Fort Smith 345 kV Conversion/New Line project, as well as the change of project from Chisholm – Potter 345 kV to Beckham County - Potter 345 kV. Calculations are based off of the original consolidated portfolio costs.

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Figure 5.11 shows the B/C ratio of the economic portfolio of project included in the consolidated portfolio.

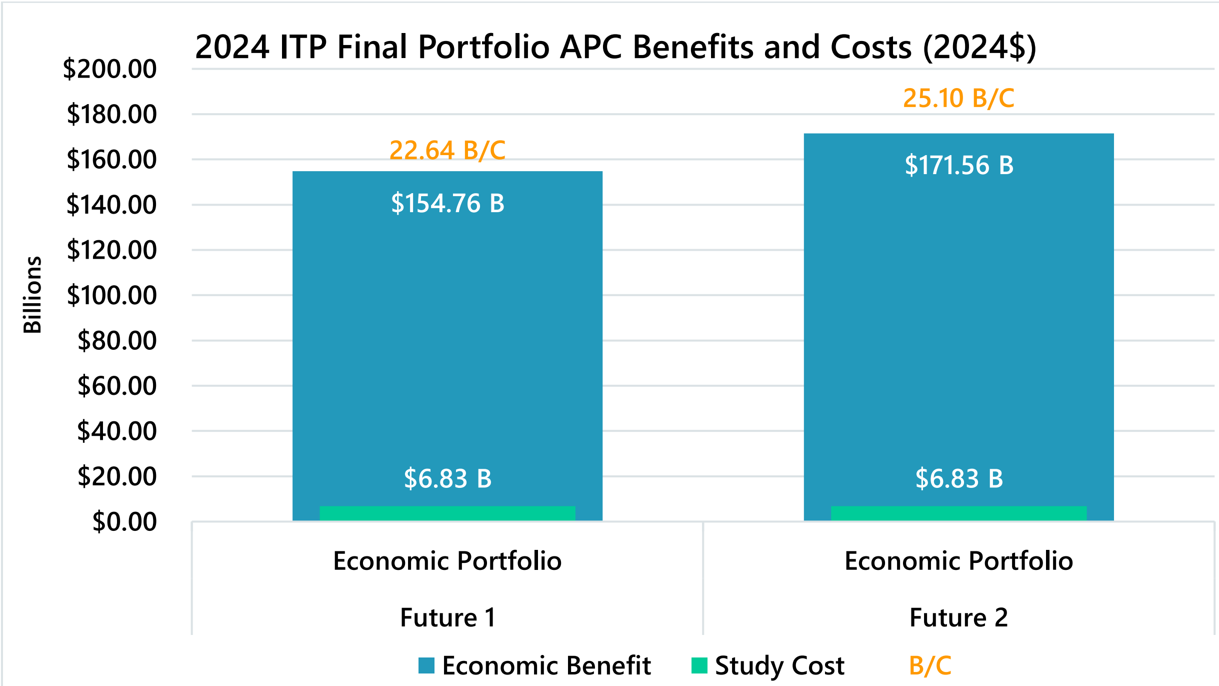

Figure 5.11: Economic Portfolio APC Benefits and Costs

Figure 5.12 shows B/C ratio of the entire consolidated portfolio. As expected, the overall B/C ratio is reduced with the inclusion of the reliability projects, but the consolidated portfolio is still expected to produce benefits well over the cost of the projects.

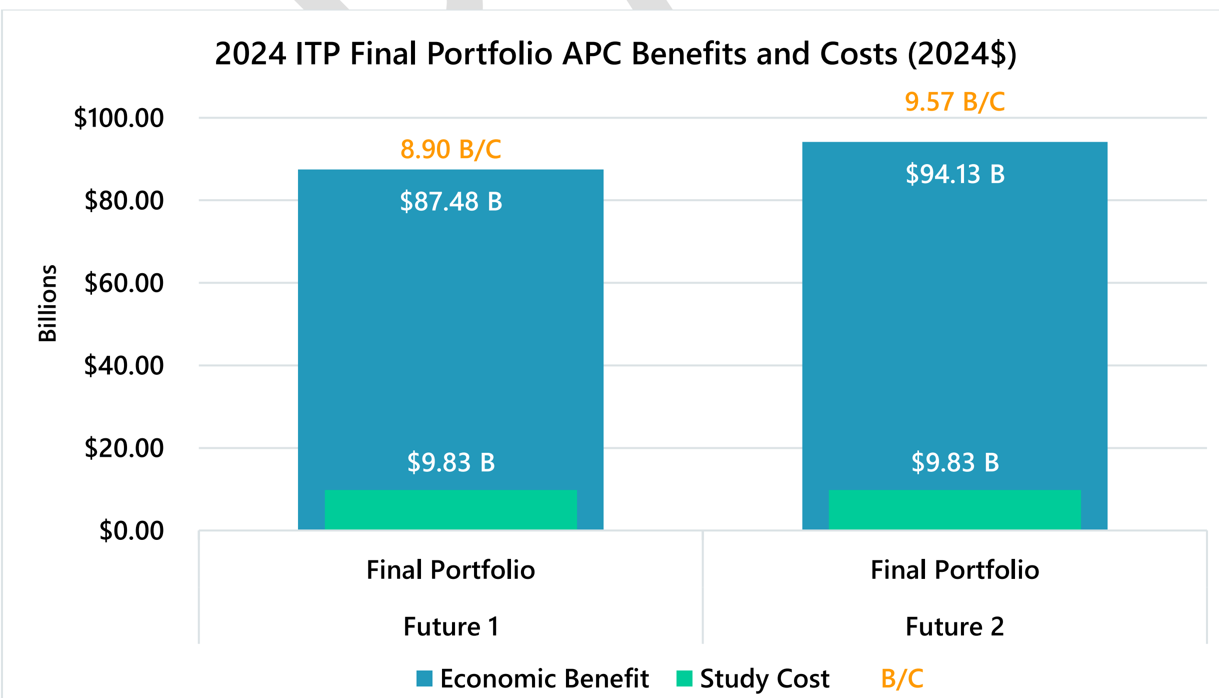

Figure 5.12: Consolidated Portfolio APC Benefits and Costs

Figure 5.13 below shows the break-even and payback dates of the consolidated portfolio assuming all projects are placed in-service by 1/1/2028. The break-even year is reflective of the first year that the one-year APC benefits are expected to outweigh the portfolio ATRR. The payback year is reflective of the year that the cumulative APC benefits are expected to exceed the 40-year PV costs of the portfolio. The consolidated portfolio is expected to break even within the first year of being placed in service and expected to pay back total investment within the first two years. This calculation provides a measure of comfort that SPP's members will see a quick return on investment in the recommended portfolio. Realistically, this payback period will not occur because not all projects in the consolidated portfolio will receive an NTC, nor will they be in-service by 2028.

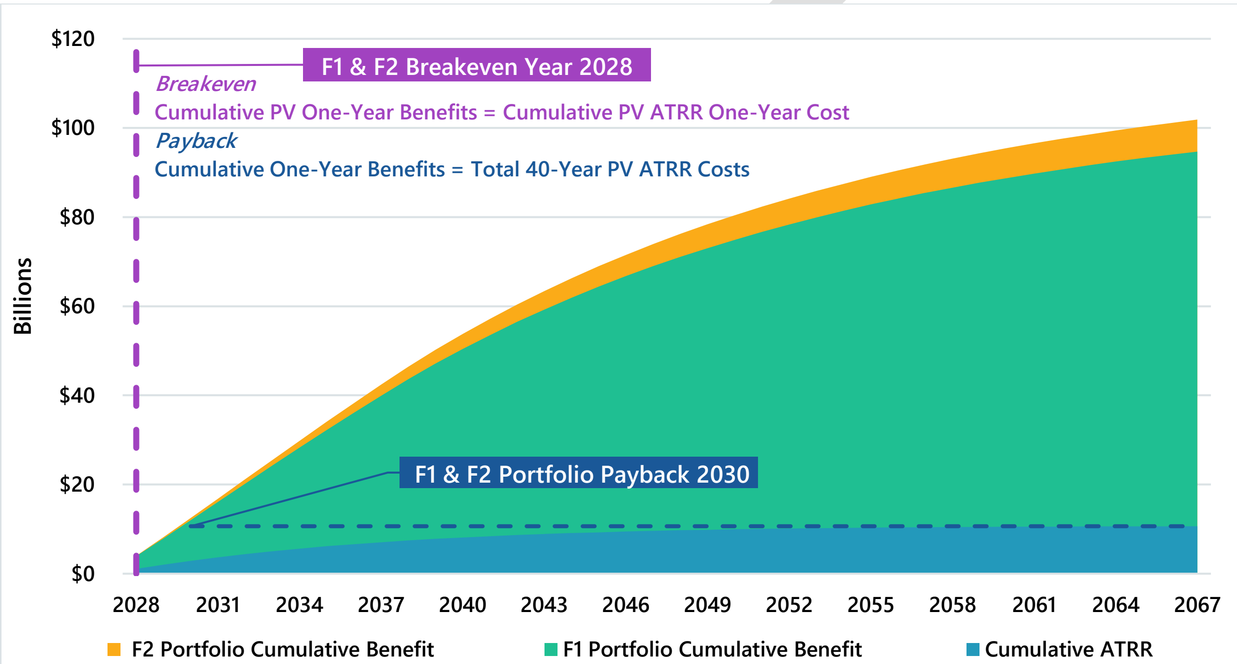

Figure 5.13: Consolidated Portfolio Break-even and Payback Dates

5.7 STAGING

Staging is the process by which the need date for each project is determined. The staging methodology can be found in the ITP Manual section 6.3.

Through stakeholder collaboration, SPP adjusted the project lead times from 48 months to 60 months for EHV projects spanning more than 100 miles. Supply chain complications prompted the stakeholders to move for SPP to collaborate with all TOs to confirm feasible lead times were included in staging analysis. By incorporating more realistic in-service dates, SPP improved the accuracy of the projects in future model cycles. The Transmission Working Group (TWG) and Economic Studies Working Group (ESWG) also moved to assign a need date of Nov. 12, 2024, to all projects addressing winter weather needs. This assignment reflects that SPP has already observed these needs in real time, and projects need to be in service as soon as possible.

SPP staff staged reliability, short circuit, and persistent operational projects to the earliest model season for the needs each project solves. Economic projects were staged to the year when the benefit to cost ratio is greater than one.

SPP staff staged the final reliability projects to share the projected in-service date of the project that was driving the final reliability need. For the Wisdom 161/69 kV transformer project, an additional project was needed to solve final reliability needs. The selected project, Spencer to Wisdom 69 kV rebuild, also solves the same needs as the new transformer, so no NTC will be given for the transformer.

The results of the staging milestone are shown in the NTC recommendation Table 8.1 at the end of this report.

5.7.1 RELIABILITY STAGING

SPP staff staged the reliability projects to the earliest season of the needs solved by that project. The staging dates for all reliability projects are shown below in Table 5.18.

PROJECT DESCRIPTION	RELIABILITY NEED DATE	LEAD TIME (MONTHS)	PROJECTED IN-SERVICE DATE	NTC/ NTC-C
15th Ave - Watertown 115 kV Rebuild	6/1/2031	48	6/1/2031	NTC
Ainsworth - Bassett 115 kV Ckt 1 New Line	6/1/2029	42	6/1/2029	NTC-C
Aurora - Central City 115 kV Ckt 1 New Line	6/1/2026	42	5/12/2028	NTC
Bismarck - East Bismarck 115 kV Rebuild	6/1/2030	30	5/12/2027	NTC
Brown - Colbert 138 kV Terminal Equipment	6/1/2033	18	1/1/2030	NTC
Channing 230 kV Capacitor	6/1/2025	24	11/12/2026	NTC
Colbert 138 kV Capacitor	6/1/2029	24	6/1/2029	NTC
Crane Creek - Robinson Lake 115 kV New Line	4/1/2032	42	5/12/2028	NTC
Dawson County - Williston 230 kV Ckt 1 New Line	6/1/2025	42	5/12/2028	NTC-C
Denver - Mid America 69 kV San Andreas - Seminole 115 kV Tap Intersection	6/1/2025	24	11/12/2026	NTC
Ellisville - Simpson 115 kV New Line, Zahl 115 kV Capacitor	6/1/2025	42	5/12/2028	NTC
Finstad - Logan 345 kV New Line, Leland Olds - Logan 345 kV Voltage Conversion	12/1/2032	60	12/1/2032	NTC-C
Finstad - Satterwaite 115 kV New Line	6/1/2033	42	5/12/2028	NTC
Frankford - Quaker 115 kV Rebuild	6/1/2025	30	5/12/2027	NTC
Gaines – Riley - Mid America - Mid-Denver Tap 69 kV Rebuild*	11/12/2026	30	11/12/2026	NTC
Grapevine - Kingsmill 115 kV New Line	6/1/2025	42	5/12/2028	NTC
Hanson County 115 kV System Reconfiguration	6/1/2025	36	11/12/2027	NTC-C
Harrisburg – Lincoln 115 kV Rebuild*	5/12/2027	30	5/12/2027	NTC
Hutchinson 115 kV Capacitor*	11/12/2027	24	11/12/2027	NTC
Iron House - Texaco 115 kV Ckt 1 New Line	6/1/2025	42	5/12/2028	NTC
Kingsbury County 115kV Voltage Conversion	6/1/2025	30	5/12/2027	NTC-C
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild	6/1/2031	30	5/12/2027	NTC
Lincoln – Sioux Falls 115 kV Terminal Equipment*	5/12/2027	18	5/12/2027	NTC
Logan - Magic City 230 kV Ckt 1 New Line	12/1/2032	60	12/1/2032	NTC-C / TBD
Lubbock East - Lubbock South 115 kV Terminal Equipment*	6/1/2025	18	5/12/2026	NTC
Lynch - Medanos 115 kV Ckt 1 New Line	12/1/2028	42	12/1/2028	NTC-C

PROJECT DESCRIPTION	RELIABILITY NEED DATE	LEAD TIME (MONTHS)	PROJECTED IN-SERVICE DATE	NTC/ NTC-C
Maddox - Pearle 115 kV Rebuild*	12/1/2028	36	12/1/2028	NTC
Madison South Dakota Area 115 kV System Reconfiguration	12/31/2025	36	12/31/2025	NTC
Marion South Dakota Area 115 kV Voltage Conversion	6/1/2025	36	11/12/2027	NTC-C
Moore County - Xit 230 kV Ckt 1 New Line	6/1/2025	42	5/12/2028	NTC-C
Moore County 230/115 kV Ckt 2 Transformer*	5/12/2028	24	5/12/2028	NTC-C
Mount Vernon 115 kV Capacitor*	11/12/2027	24	11/12/2027	NTC
Patent Gate - Pioneer 345 kV Ckt 1 New Line	4/1/2025	48	11/12/2028	NTC-C
Phantom - Crossroads - Potter 765 kV Ckt 1 New Line	4/1/2025	60	11/12/2029	NTC-C
Pioneer - Sanderson 115 kV Ckt 1 New Line	6/1/2028	42	5/12/2028	NTC
Ren - Williston 115 kV Rebuild*	5/12/2028	30	5/12/2028	NTC
Roadrunner 345/115 kV Ckt 2 Transformer	6/1/2025	24	11/12/2026	NTC
Roadrunner 345/115 kV Ckt 3 Transformer	6/1/2025	24	11/12/2026	NTC
Sioux Falls South Dakota Area 115 kV System Reconfiguration	6/1/2025	30	5/12/2027	NTC-C
Spencer - Wisdom 69 kV Rebuild*	12/1/2025	30	5/12/2027	NTC
Spring Brook - Twelve Mile 345 kV Ckt 1 New Line	4/1/2032	48	4/1/2032	NTC-C
Sub 1209 - Sub 1250 161 kV Rebuild	6/1/2028	30	6/1/2028	NTC-C
Sub 1209 - Sub 1358 161 kV Rebuild	6/1/2028	30	6/1/2028	NTC
Sub 1250 - Sub 1358 161 kV Rebuild	6/1/2028	30	6/1/2028	NTC
W Banks 345/115 kV Transformer	4/1/2033	60	1/1/2032	NTC-C
Wisdom 161/69 kV Transformer	12/1/2025	24	11/12/2026	

Table 5.18: Reliability Staging Dates

5.7.2 ECONOMIC STAGING

SPP staff staged the economic projects to the year when the benefit to cost ratio is above 1. The staging dates for all economic projects are shown below in Table 5.19.

PROJECT DESCRIPTION	ECONOMIC NEED DATE	LEAD TIME (MONTHS)	PROJECTED IN-SERVICE DATE	NTC/ NTC-C
Alliance - Snake Creek 115 kV Rebuild	1/1/2025	30	5/12/2027	TBD
Antelope - Holt County 345 kV Ckt 1 New Line	1/1/2025	48	11/12/2028	NTC-C
Belfield - Maurine - New Underwood - Laramie River 345 kV New Line	1/1/2025	60	11/12/2029	NTC-C
Bismarck - East Bismarck 115 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Blackberry - Neosho 345 kV Rebuild	1/1/2036	48	1/1/2036	
Brown - Colbert 138 kV Terminal Equipment	1/1/2030	18	1/1/2030	NTC
Bull Shoals - Midway Jordan 161 kV Rebuild	1/1/2030	30	5/12/2027	TBD
Butler - Midian 138 kV Rebuild	1/1/2028	30	1/1/2028	NTC
Butler South - Tallgrass 138 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Catoosa 161/138 kV Transformer	1/1/2025	24	11/12/2026	NTC
CDC East - Tulsa North 138 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Chadron - Dunlap 115 kV Ckt 1 Rebuild	1/1/2034	36	1/1/2034	
Chisholm - Maize - Evans Energy Center North 138 kV Ckt 1 Rebuild	1/1/2032	42	1/1/2032	NTC-C
Chisholm - Potter 345 kV New Line	1/1/2035	60	11/12/2029	NTC-C

PROJECT DESCRIPTION	ECONOMIC NEED DATE	LEAD TIME (MONTHS)	PROJECTED IN-SERVICE DATE	NTC/ NTC-C
Crane Creek - Robinson Lake 115 kV New Line	1/1/2028	42	5/12/2028	NTC
Evans Energy Center North - Halstead 138 kV Ckt 1 New Line	1/1/2045	48	1/1/2045	
Farber - Sumner County No. 10 Belle Plain 138 kV Rebuild	1/1/2025	30	5/12/2027	NTC-C
Finstad - Satterwaite 115 kV New Line	1/1/2028	42	5/12/2028	NTC
Gering Tap - Morrill 115 kV Ckt 1 Rebuild	1/1/2036	30	1/1/2036	
Gering Tap - Scotts Bluff 115 kV Ckt 1 Rebuild	1/1/2025	36	5/12/2027	TBD
Hoskins - Stanton North 115 kV Rebuild	1/1/2026	30	5/12/2027	NTC
Lamar 161/69 kV Ckt 2 Transformer	1/1/2036	30	1/1/2036	
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Martin City (East) - Martin City (West) 161 kV Terminal Equipment	1/1/2025	18	5/12/2026	NTC
Maud Tap 138 kV Terminal Upgrade	1/1/2025	18	5/12/2026	NTC
Morrill - Snake Creek 115 kV Ckt 1 Rebuild	1/1/2025	30	5/12/2027	TBD
Nashua 345/161 kV Ckt 2 Transformer	1/1/2025	24	11/12/2026	NTC-C
Phantom - Crossroads - Potter 765 kV Ckt 1 New Line	1/1/2025	60	11/12/2029	NTC-C
Pioneer - Sanderson 115 kV Ckt 1 New Line	1/1/2028	42	5/12/2028	NTC
Roadrunner 345/115 kV Ckt 3 Transformer	1/1/2025	24	11/12/2026	NTC
S3458 - S3740 345 kV Ckt 2 New Line	1/1/2025	48	11/12/2028	NTC-C
Tallgrass - Weaver 138 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Tulsa North 345/138 kV Ckt 2 Transformer	1/1/2025	24	11/12/2026	NTC
W Banks 345/115 kV Transformer	1/1/2032	60	1/1/2032	NTC-C

Table 5.19: Economic Staging Dates

5.7.3 OPERATIONAL STAGING

SPP staff staged the operational projects to 11/12/2024. This is the date of NTC issuance following approval by the board of directors. Staging dates for all operational projects are shown below in Table 5.20.

PROJECT DESCRIPTION	OPERATIONAL NEED DATE	LEAD TIME (MONTHS)	PROJECTED IN-SERVICE DATE	NTC/ NTC-C
Alliance - Snake Creek 115 kV Terminal Upgrade	Date of NTC Issuance	18	5/12/2026	TBD
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	Date of NTC Issuance	30	5/12/2027	NTC-C
Conway - Kirby 115 kV Terminal Upgrade	Date of NTC Issuance	18	5/12/2026	NTC
Edwardsville 161/115 kV Transformer	Date of NTC Issuance	24	11/12/2026	NTC
Nashua 345/161 kV Ckt 2 Transformer	Date of NTC Issuance	24	11/12/2026	NTC-C
Sidney – Holcomb 345 kV New Line	Date of NTC Issuance	60	11/12/2029	NTC-C

Table 5.20: Operational Staging Dates

5.7.4 SHORT CIRCUIT STAGING

SPP staff staged the short circuit projects to the earliest season of the needs solved by that project. The staging dates for all short circuit projects are shown below in Table 5.21.

PROJECT DESCRIPTION	NEED DATE	LEAD TIME (MONTHS)	PROJECTED IN-SERVICE DATE	NTC/ NTC-C
S1260 161 kV Breaker Replacement	6/1/2025	18	5/12/2026	
Tinker 138 kV Two Breaker Replacements	6/1/2025	18	5/12/2026	NTC

Table 5.21: Short Circuit Staging Dates

5.7.5 WINTER WEATHER STAGING

SPP staff staged the winter weather projects to the earliest season of the needs solved by that project. The staging dates for all winter weather projects are shown below in Table 5.22.

PROJECT DESCRIPTION	NEED DATE	LEAD TIME (MONTHS)	PROJECTED IN-SERVICE DATE	NTC/ NTC-C
Aurora - Reeds Spring 161 kV Rebuild	12/1/2025	36	11/12/2027	NTC-C
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	12/1/2025	30	5/12/2027	NTC-C
Branson North - Branson Northwest -North Branson - Reed Springs 161 kV Rebuild	12/1/2025	30	5/12/2027	NTC
Branson North - Ozark Dam 161 kV Ckt 1 Rebuild	12/1/2025	30	5/12/2027	NTC
Buffalo Flats - Delaware 345 kV New Line	12/1/2028	60	11/12/2029	NTC-C
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps	12/1/2025	24	11/12/2026	NTC-C / TBD[36]
Delaware - Monett 345 kV Ckt 1 New Line	12/1/2025	60	11/12/2029	NTC-C
Elm Creek - Tobias 345 kV New Line	12/1/2028	48	12/1/2028	NTC-C
Holcomb - Sidney 345 kV Ckt 1 New Line	12/1/2028	60	11/12/2029	NTC-C
Monett - North Branson 345 kV Ckt 1 New Line	12/1/2025	48	11/12/2028	NTC-C
N Reeds Spring - S Reeds Spring 161 kV Rebuild	12/1/2025	30	5/12/2027	NTC
Ozark Dam - Forsyth North - Ozark South 161 kV Voltage Conversion	12/1/2025	30	5/12/2027	NTC-C

Table 5.22: SPP Staff Recommended Winter Weather Staging Dates

The TWG and ESWG moved to consider all winter weather projects the same as persistent operational projects and stage them at the NTC issuance date. The staging dates from TWG/ESWG for all winter weather projects are shown below in Table 5.23.

PROJECT DESCRIPTION	NEED DATE[37]	LEAD TIME (MONTHS)	PROJECTED IN-SERVICE DATE	NTC/ NTC-C
Aurora - Reeds Spring 161 kV Rebuild	11/12/2024	36	11/12/2027	NTC-C
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	11/12/2024	30	5/12/2027	NTC-C
Branson North - Branson Northwest -North Branson - Reed Springs 161 kV Rebuild	11/12/2024	30	5/12/2027	NTC
Branson North - Ozark Dam 161 kV Ckt 1 Rebuild	11/12/2024	30	5/12/2027	NTC
Buffalo Flats - Delaware 345 kV New Line	11/12/2024	60	11/12/2029	NTC-C

[36] SPP facilities included in this upgrade will receive an NTC-C

[37] The TWG/ESWG are assuming 11/12/2024 is the expected NTC issuance date

PROJECT DESCRIPTION	NEED DATE[37]	LEAD TIME (MONTHS)	PROJECTED IN-SERVICE DATE	NTC/ NTC-C
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps	11/12/2024	24	11/12/2026	NTC-C / TBD[38]
Delaware - Monett 345 kV Ckt 1 New Line	11/12/2024	60	11/12/2029	NTC-C
Elm Creek - Tobias 345 kV New Line	11/12/2024	48	11/12/2028	NTC-C
Holcomb - Sidney 345 kV Ckt 1 New Line	11/12/2024	60	11/12/2029	NTC-C
Monett - North Branson 345 kV Ckt 1 New Line	11/12/2024	48	11/12/2028	NTC-C
N Reeds Spring - S Reeds Spring 161 kV Rebuild	11/12/2024	30	5/12/2027	NTC
Ozark Dam - Forsyth North - Ozark South 161 kV Voltage Conversion	11/12/2024	30	5/12/2027	NTC-C

Table 5.23: TWG-ESWG Recommended Winter Weather Staging Dates

5.7.6 STAGING ADJUSTMENTS

The Chisholm to Potter 345 kV New Line project supports the 765 kV line between Phantom to Crossroads to Potter (as detailed in section 6.1.12.2). The economic need date for Chisholm to Potter was 2035, but the need date was changed to the in-service date of Phantom to Crossroads to Potter.

Staff also reached out to TO's for lead times on the projects that did not get NTC recommendations from the portfolio. The feedback received is listed below in Table 5.24.

PROJECT DESCRIPTION	STANDARD LEAD TIME	NEW LEAD TIME	NTC/ NTC-C
15th Ave - Watertown 115 kV Rebuild	30	48	NTC
Blackberry - Neosho 345 kV Rebuild	36	48	
Chisholm - Maize- Evans Energy Center North 138 kV Ckt 1 Rebuild	30	42	NTC-C
Evans Energy Center North - Halstead 138 kV Ckt 1 New Line	42	48	
Lamar 161/69 kV Ckt 2 Transformer	24	30	
Logan - Magic City 230 kV Ckt 1 New Line	42	60	NTC-C /TBD
W Banks 345/115 kV transformer	24	60	NTC-C

Table 5.24: Staging Adjustments to Lead Time

5.7.7 DUAL PORTFOLIO PROJECTS

Projects that solved needs in multiple portfolios must be staged in both portfolios to determine which has the earliest need date. Table 5.25 gives the need dates for each portfolio and which portfolio was selected to drive the in-service date for that project.

[38] SPP facilities included in this upgrade will receive an NTC-C

Project Description	Reliability Need Date	Economic Need Date	Winter Weather or Ops Need Date
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild			WW: 12/1/2025 Ops: Date of NTC Issuance
Bismarck - East Bismarck 115 kV Rebuild	6/1/2030	1/1/2025	
Brown - Colbert 138 kV Terminal Equipment	6/1/2033	1/1/2030	
Crane Creek - Robinson Lake 115 kV New Line	4/1/2032	1/1/2028	
Finstad - Satterwaite 115 kV New Line	6/1/2033	1/1/2028	
Holcomb - Sidney 345 kV Ckt 1 New Line			WW: 12/1/2028 Ops: Date of NTC Issuance
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild	6/1/2031	1/1/2025	
Nashua 345/161 kV Ckt 2 Transformer		1/1/2025	11/12/2024
Phantom - Crossroads - Potter 765 kV Ckt 1 New Line	4/1/2025	1/1/2025	
Pioneer - Sanderson 115 kV Ckt 1 New Line	6/1/2028	1/1/2028	
Roadrunner 345/115 kV Ckt 3 Transformer	6/1/2025	1/1/2025	
W Banks 345/115 kV Transformer	4/1/2033	1/1/2032	

Table 5.25: Multi-Portfolio Staging

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6 PROJECT RECOMMENDATIONS

6.1 RELIABILITY, ECONOMIC, WINTER WEATHER, AND PERSISTENT OPERATIONAL PROJECTS

6.1.1 ASSOCIATED ELECTRIC COOPERATIVE INCORPORATED (AECI)

6.1.1.1 *LAMAR 161/69 KV CIRCUIT 2 TRANSFORMER (ECONOMIC)*

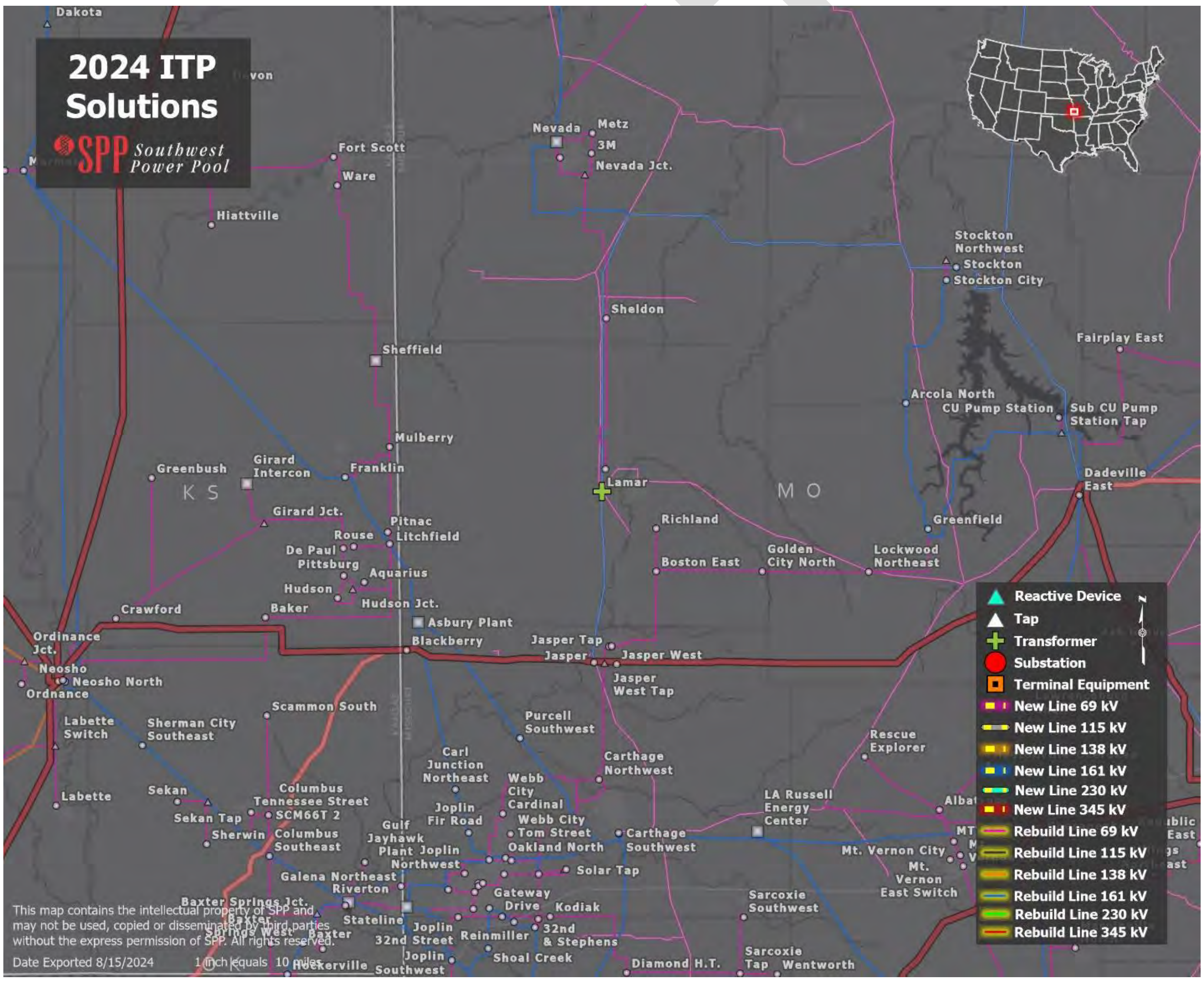

Figure 6.1: AECI: Lamar 161/69 kV Circuit 2 Transformer

The southwest Missouri region is the recipient of significant transmission buildout in the 2024 ITP due to the conditions observed during winter storm Elliott. With these projects solving multiple congestion points on SPP's eastern seam, more power is allowed to flow east and begins to congest the 161/69 kV Lamar transformer upon loss of the 345kV line from Blackberry to Jasper. This transformer also becomes congested when relaxing elements on the 161kV north-to-south corridor. Adding a second 161/69 kV transformer at Lamar would relieve the congestion and increase the economic potential in this area. This project includes potential cost sharing opportunities with AECI through the 2024 Joint & Coordinated System Planning assessment (JCSP).

6.1.2 AMERICAN ELECTRIC POWER (AEP)

6.1.2.1 *TULSA NORTH – CDC EAST 138 KV REBUILD & NEW TULSA NORTH 345/138 KV TRANSFORMER (ECONOMIC)*

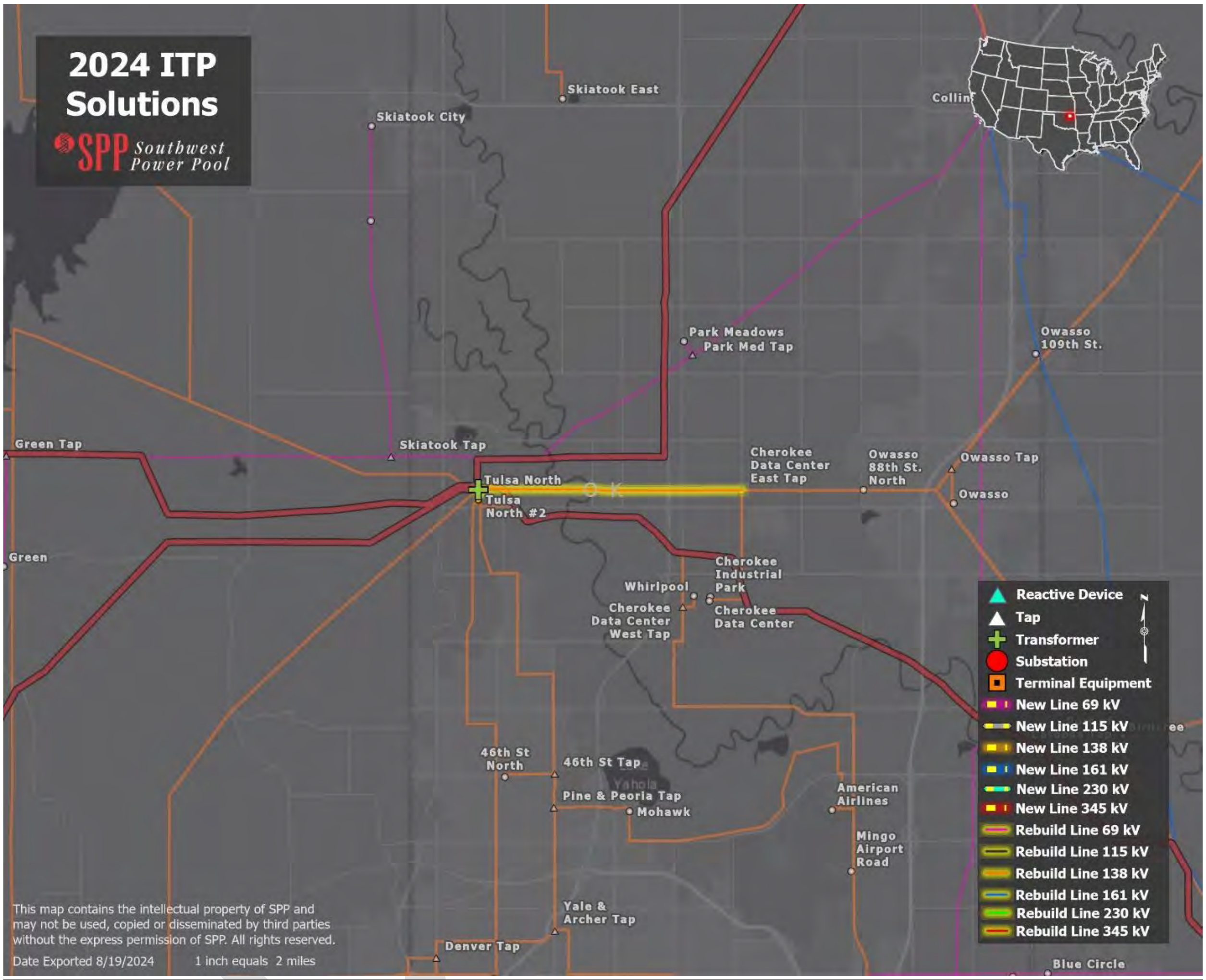

Figure 6.2: AEP: Tulsa North – CDC East 138 kV Rebuild & New Tulsa North 345/138 kV XFR

Two projects were selected in the Tulsa, Oklahoma area to work together to provide economic benefit by relieving congestion. The first project is rebuilding the Tulsa North to Cherokee Data Center East 138 kV line and the second is adding a 345/138 kV transformer at the Tulsa North substation. The most severe economic congestion addressed by this project set occurs when the existing 138 kV Tulsa North bus tie or transformer is lost. This contingency congests the Tulsa North to Pine and Peoria Tap 138 kV line due to the power having to reach the Tulsa North 138 kV bus from the south. This project set adds a redundant transformer on the main bus, mitigating both continencies. It also allows more power to flow into the city of Tulsa from the Tulsa North 138 kV substation.

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6.1.3 EMPIRE DISTRICT ELECTRIC COMPANY (EMDE)

6.1.3.1 *BRANSON 345 KV OVERLAY AND 161 KV UNDERLAY (WINTER WEATHER/PERSISTENT OPERATIONAL)*

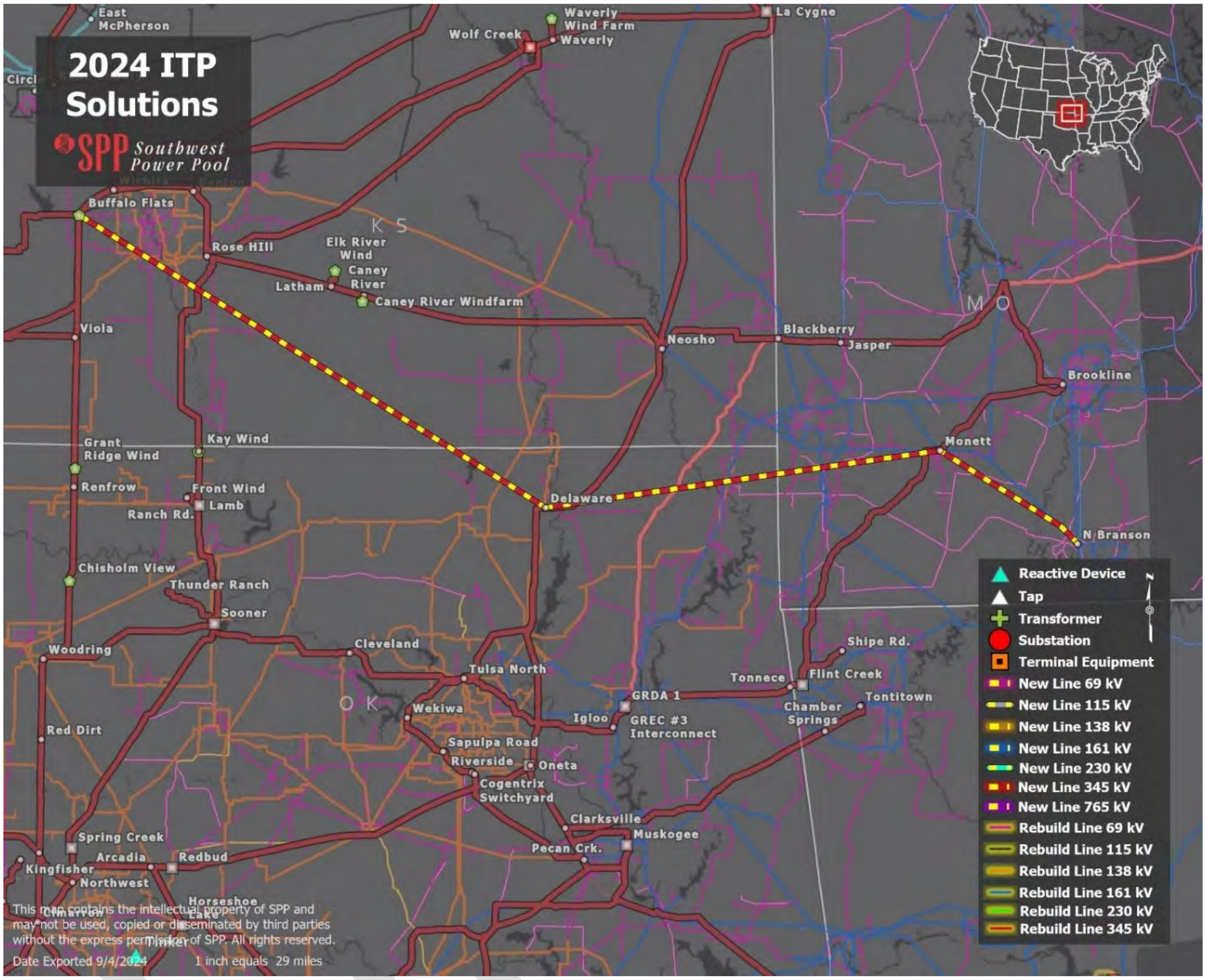

Figure 6.3: EMDE: Branson 345 kV EHV Overlay

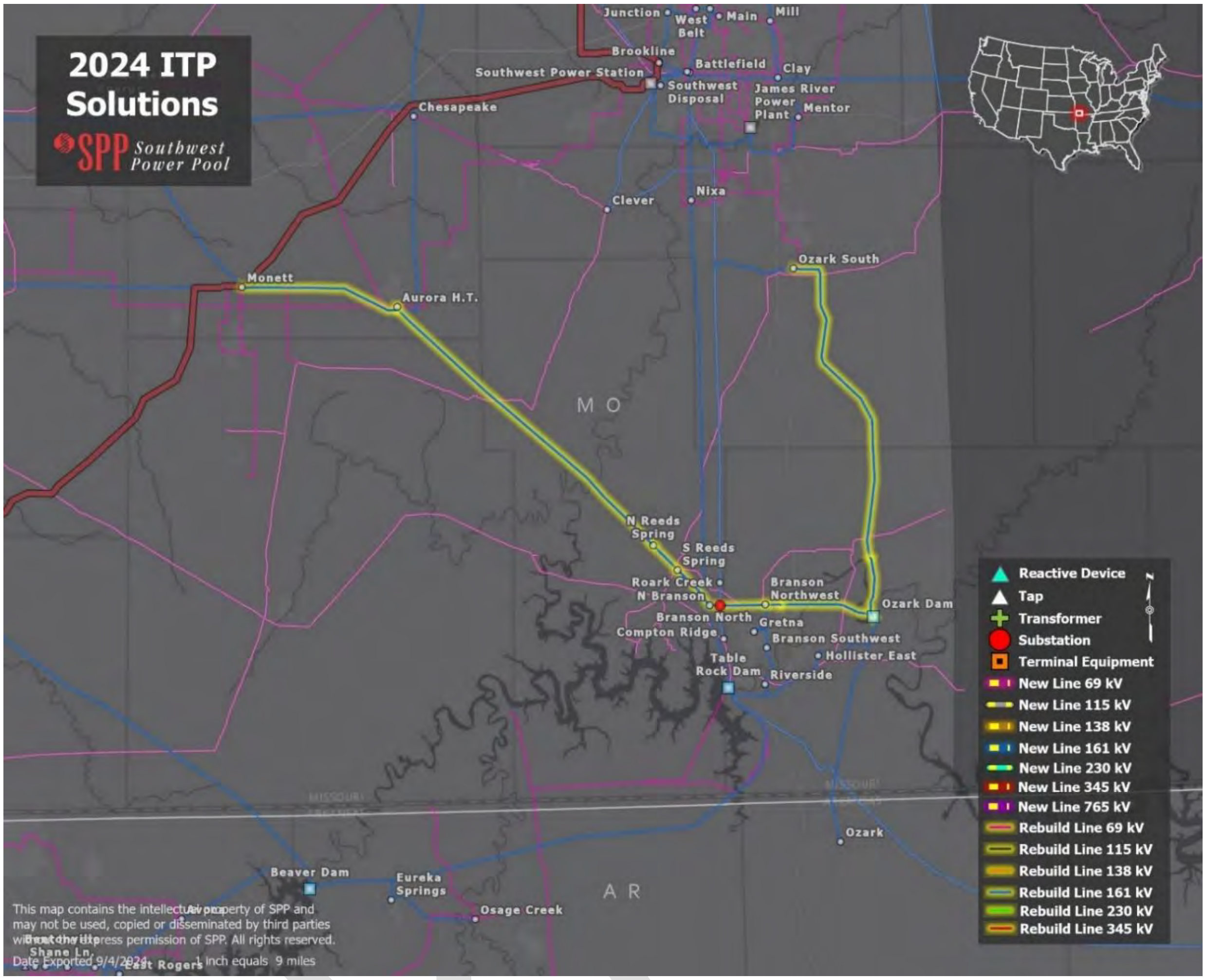

Figure 6.4: EMDE: Branson 161 kV Underlay

SPP staff selected the 345 kV overlay project from Buffalo Flats to Delaware to Monett to North Branson to enhance robustness and resiliency of the transmission system in the southern Missouri area near Branson to address recent extreme winter weather events. Many of the needs identified in this area were low voltage that were driven by a lack of supporting EHV transmission and generation deliverability to the region during Winter Storm Elliott. This project showed substantial reliability benefits and mitigated 93% of the voltage violations in the area.

The 345 kV overlay project involves the construction of approximately 316 miles of 345 kV transmission line, extending from southern Kansas to northeastern Oklahoma and into southwestern Missouri. This project offers significant advantages by enhancing the transmission of low-cost energy to eastern areas of the SPP footprint. Additionally, it boosts power transfer capacity and improves reactive power support in the region, delivering substantial benefits in terms of reliability and resiliency.

The synergy this project brings to reliability under extreme winter conditions, as well as reducing cost to load in southwest Missouri, was a large driver for why it was chosen from our MV portfolios. The project has also shown to release bottlenecked generation by eliminating market constraints in the target area. Ultimately, the project contributes to a more robust transmission system, better equipped to handle increased load growth and withstand extreme weather conditions.

In addition to the EHV overlay, SPP identified multiple winter weather needs on the HV system near Branson. As a result, SPP selected a series of 161 kV upgrades to further enhance the benefits of the 345 kV project (shown in Figure 6.3). These projects were selected to strengthen the 161 kV system in the area and to facilitate the connection of the 345 kV projects nearby to ensure adequate transfer capability is available.

To facilitate the 345 kV to 161 kV connection, SPP recommends that the Compton Ridge to Roark Creek, Table Rock to Nixa, and Reeds Spring to Branson Northwest 161 kV lines be tapped near the point at which they intersect to serve as the point of interconnection for the 345 kV overlay project.

Along with the winter weather needs, persistent operational congestion has appeared in recent years throughout the 161 kV corridor from Monett to Ozark Dam. To relieve this congestion the corridor would be rebuilt to allow for adequate powerflow to occur in real time.

Finally, the 69 kV line from Ozark South to Forsyth to Ozark Dam, which is out of service due to environmental and safety concerns, would be rebuilt to 161 kV to support voltage and complement the rebuilds of the remaining 161 kV projects in the corridor.

Merging the benefit of the EHV and HV projects, shown in Table 6.1, in the Branson area is required to equip the Southeastern Missouri area considering the extreme weather conditions that have been experienced. The 345 kV line would allow for increased transfer into the area while the HV rebuilds would adequately distribute the newfound power while avoiding congestion.

In conjunction with the ITP Assessment, both overlay and underlay projects include potential cost sharing opportunities with AECI through the 2024 Joint & Coordinated System Planning (JCSP) assessment.

Upgrade Type	Upgrade	Approximate Mileage
New Line	Buffalo Flats – Delaware 345 kV	154.6
	Delaware – Monett 345 kV	114.5
	Monett – North Branson 345 kV	47.2
Rebuild	Monett – Aurora 161 kV	11.5
	Aurora – North Reed Springs 161 kV	23.7
	North Reed Springs – South Reed Springs 161 kV	1.5
	South Reed Springs – Branson Northwest 161 kV	8.3
	Branson Northwest – Branson North 161 kV	0.85
	Branson North – Ozark Dam 161 kV	7
Voltage Conversion (69 kV to 161 kV)	Ozark Dam – Forsyth North	3.8
	Forsyth North – Ozark South	24.4

Table 6.1: Branson 345 kV Overlay and 161 kV Underlay

Figure 6.5 below shows the change in load LMP as a result of the full 2024 ITP portfolio. The LMP change indicates the change in cost for each zone to serve their load. Zones EMDEALL, SPCIUT, and SWPAALL are zones experiencing a significantly reduced cost to serve load due to the Branson 345 kV Overlay and 161 kV Underlay projects

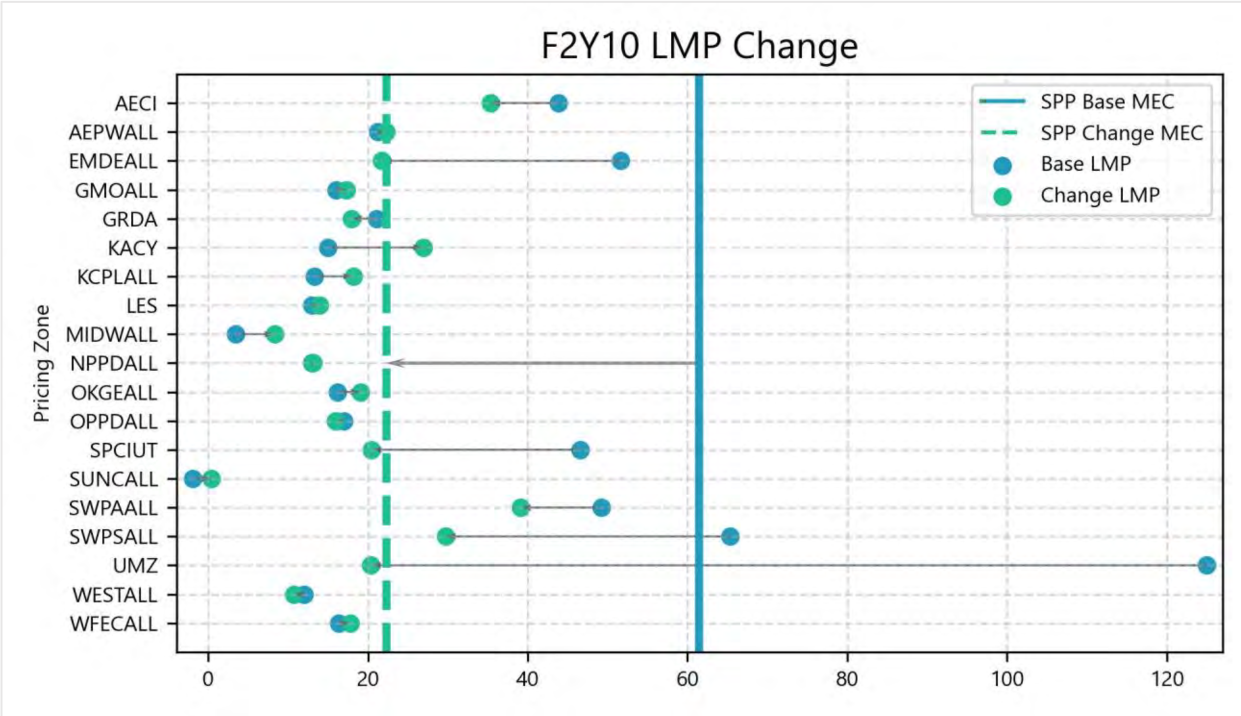

Figure 6.5: Future 2 year 10 LMP Change

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6.1.4 EVERGY-GREATER MISSOURI OPERATIONS (GMO)

6.1.4.1 *MARTIN CITY (EAST) – MARTIN CITY (WEST) 161 KV TERMINAL EQUIPMENT (ECONOMIC)*

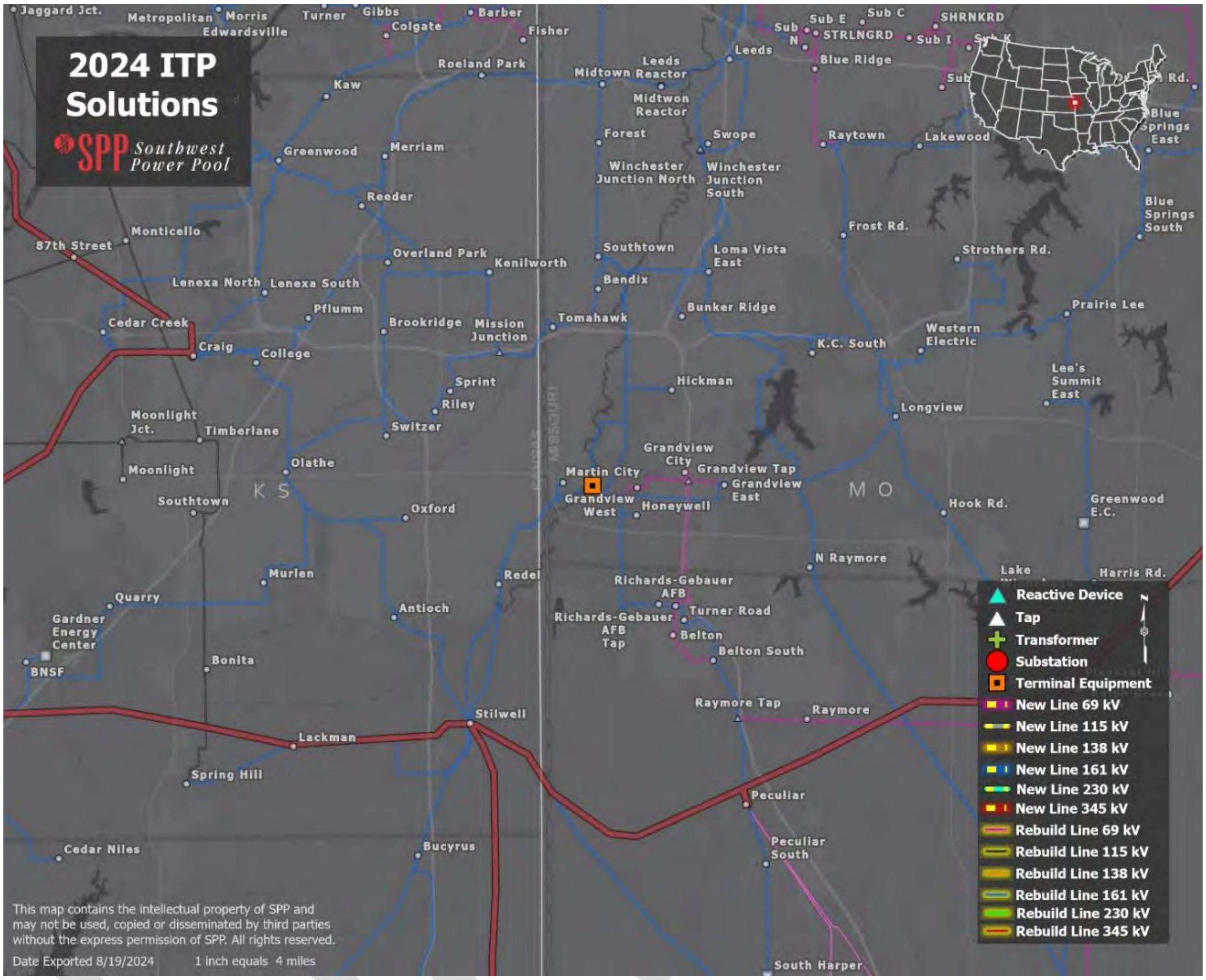

Figure 6.6: GMO: Martin City (East) – Martin City (West) 161 kV Terminal Equipment

Along the western edge of Missouri, the Martin City (East) to Martin City (West) 161 kV line experiences congestion for the loss of the 345 kV line from Peculiar to Stilwell. This congestion increases in later models and is more severe in Future 2 than in Future 1. To resolve this congestion, SPP staff recommends upgrading the terminal equipment along the line to increase the branch's rating to that of the conductor.

6.1.5 EVERGY-KANSAS CENTRAL, INC. (EKC)

6.1.5.1 *AQUARIUS – LITCHFIELD NORTH – PITNAC TAP – MULBERRY 69 KV REBUILD (ASSET MANAGEMENT)*

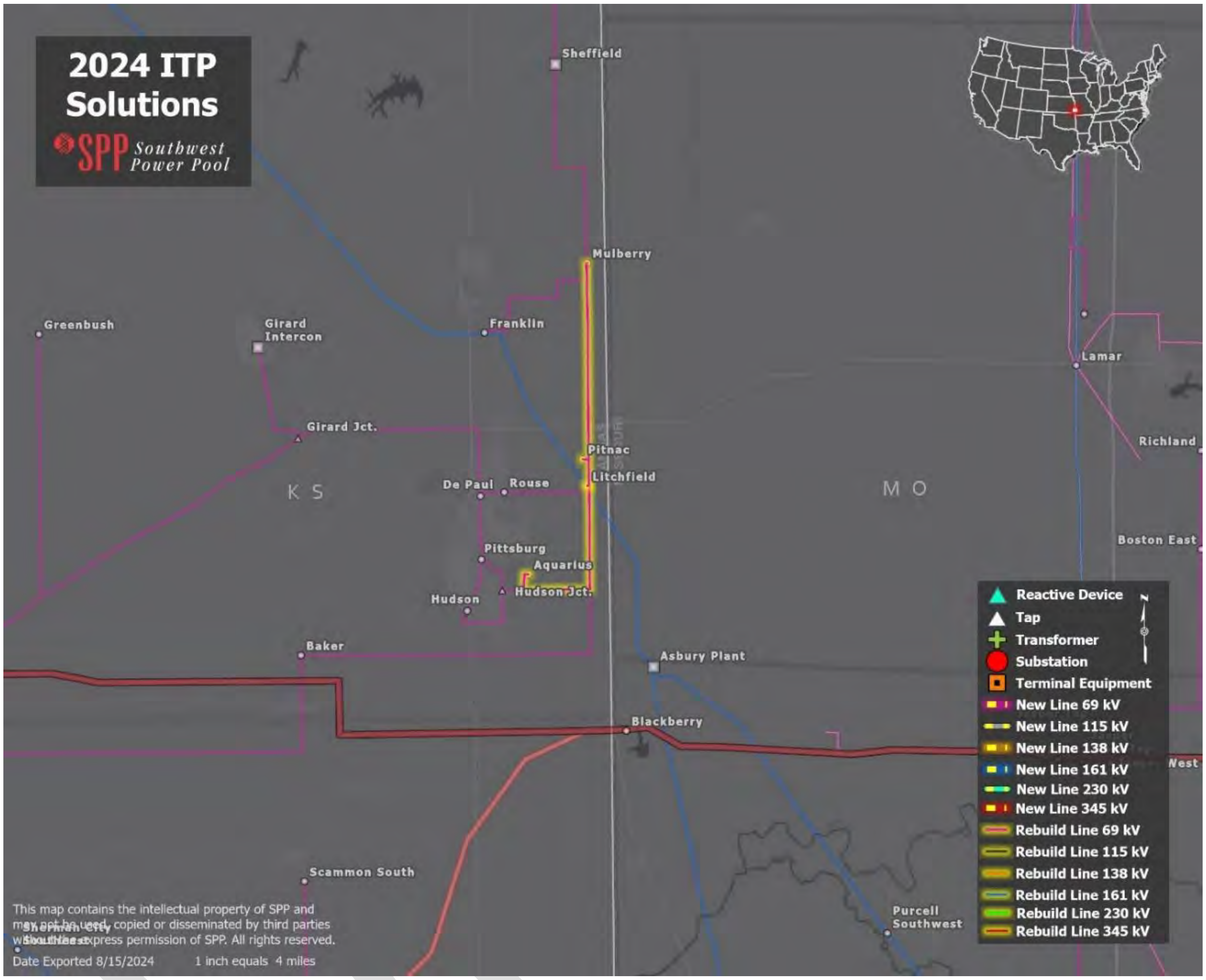

Figure 6.7: EKC: Aquarius – Litchfield North – Pitnac Tap – Mulberry 69 kV Rebuild

In southeast Kansas, the local TO identified the 69 kV lines from Aquarius to Litchfield North to Pintac Tap to Mulberry as a necessary rebuild due to its age and condition. Portions of the existing line are more than 65 years old. SPP staff confirmed that rebuilding these lines does not introduce any new violations. The final portfolio cost does not include the costs associated with these projects, as the local TO will fund these projects.

6.1.5.2 *MIDIAN – BUTLER – TALLGRASS – WEAVER 138 KV REBUILD (ECONOMIC)*

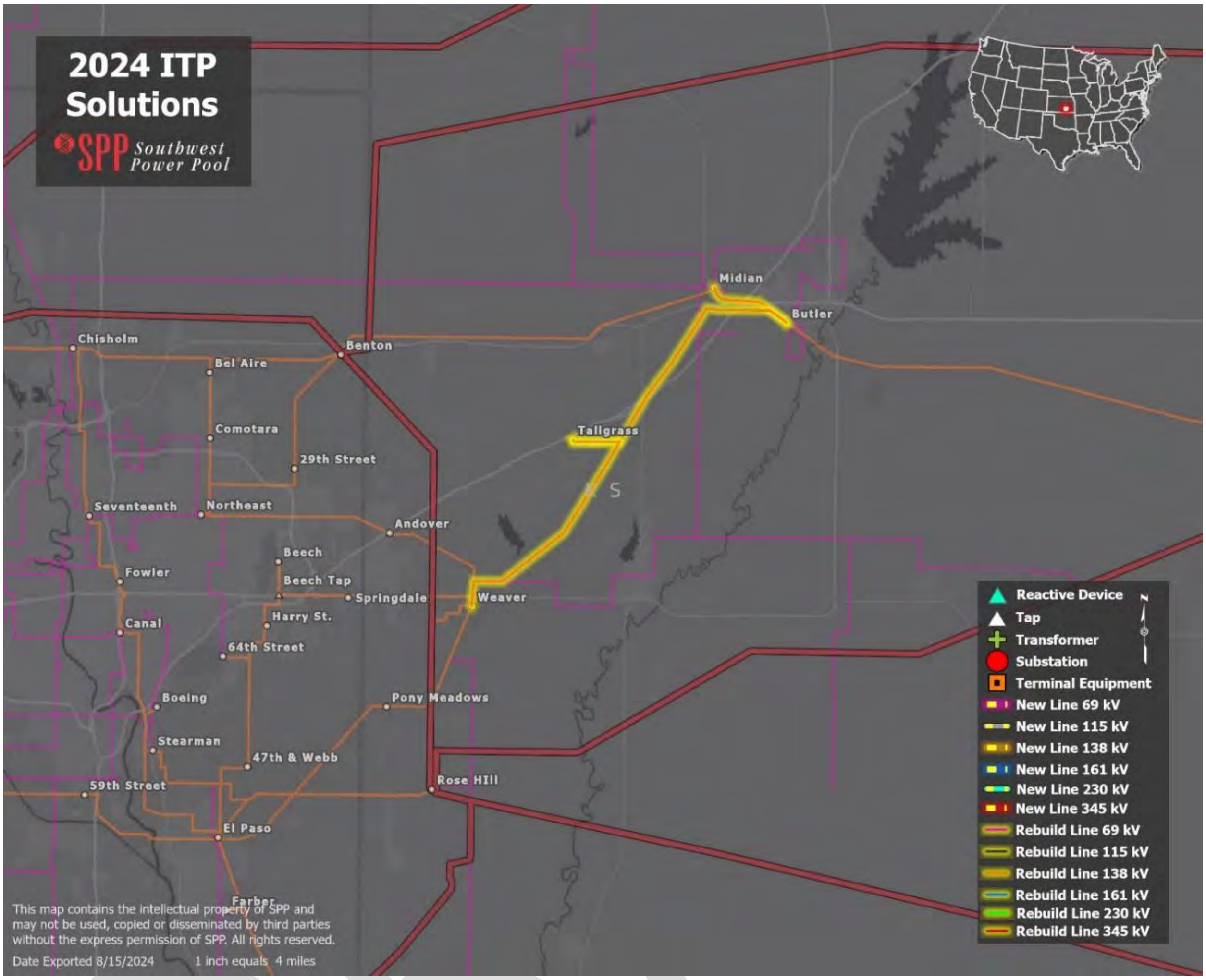

Figure 6.8: EKC: Midian – Butler – Tallgrass – Weaver 138 kV Rebuild

On the east side of Wichita, Kansas, SPP observed substantial congestion on the 138 kV lines from Midian to Butler and Tallgrass to Weaver when other nearby 138 kV branches were out of service. When the congestion on Tallgrass to Weaver 138 kV was resolved, the congestion shifted to the 138 kV line from Butler to Tallgrass. To resolve all the congestion on these constraints, SPP staff recommends rebuilding the 138 kV lines from Midian to Butler to Tallgrass to Weaver. The 2022 20-Year Assessment also identified rebuilds of these facilities as the optimal solution.

6.1.5.3 CHISHOLM – MAIZE – EVANS ENERGY CENTER NORTH 138 KV REBUILD (ECONOMIC)

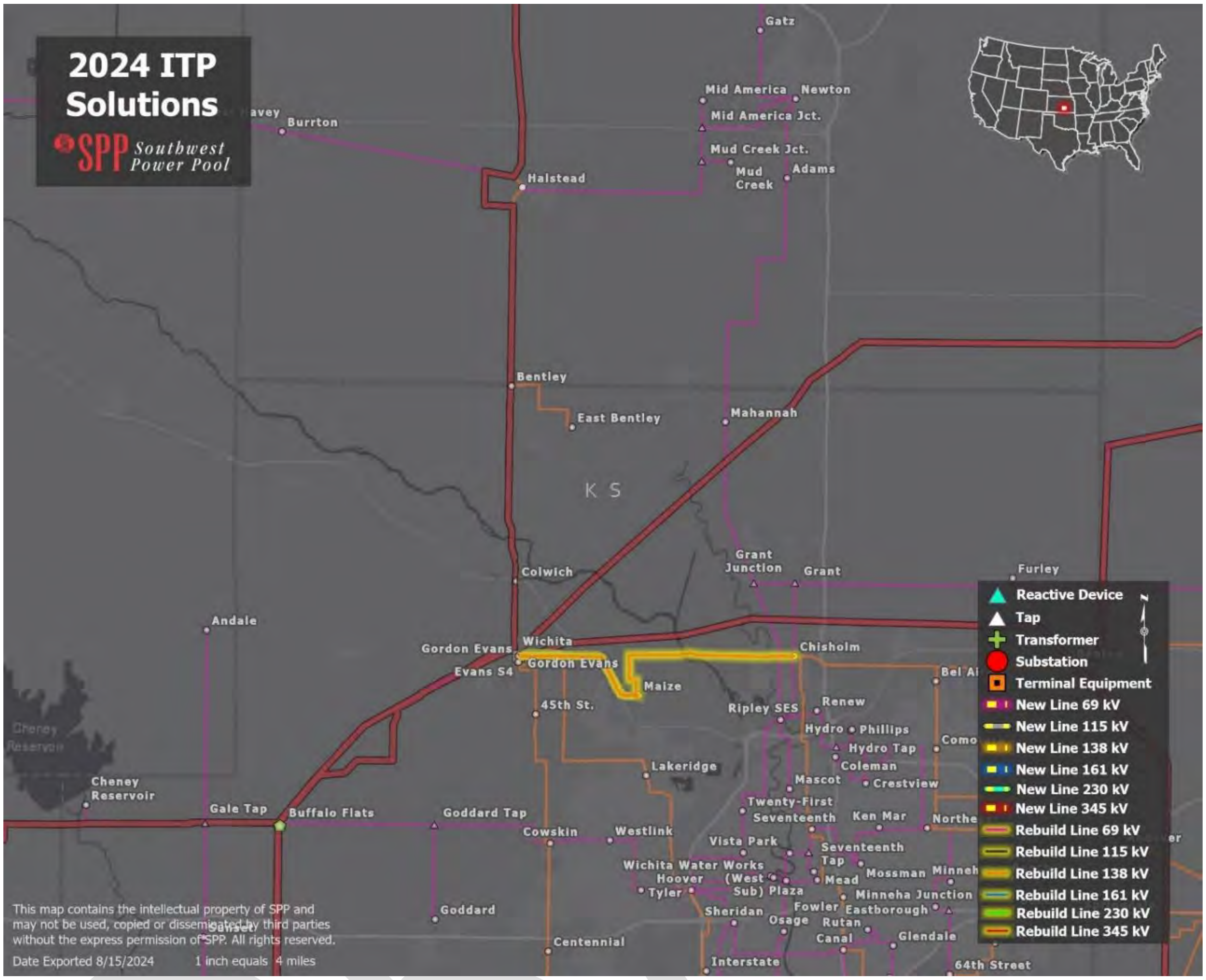

Figure 6.9: EKC: Chisholm – Maize – Evans Energy Center North 138 kV Rebuild

In Wichita, Kansas, the 138 kV line from Evans Energy Center North to Maize experiences congestion when the 345 kV line from Benton to Wichita is out of service. When the congestion on Evans Energy Center North to Maize 138 kV is relieved, it shifts the congestion to the Maize to Chisholm 138 kV line. SPP observed significant congestion in year five, and further escalated congestion in year 10, affirming the need to address this congestion. The projects SPP staff selected to address this congestion are a rebuild of Chisholm to Maize to Evans Energy Center North 138 kV. This project would resolve all congestion on Evans Energy Center North to Maize for the loss of the Benton to Wichita 345 kV line.

6.1.5.4 *EVANS ENERGY CENTER NORTH – HALSTEAD 138 KV NEW LINE (ECONOMIC)*

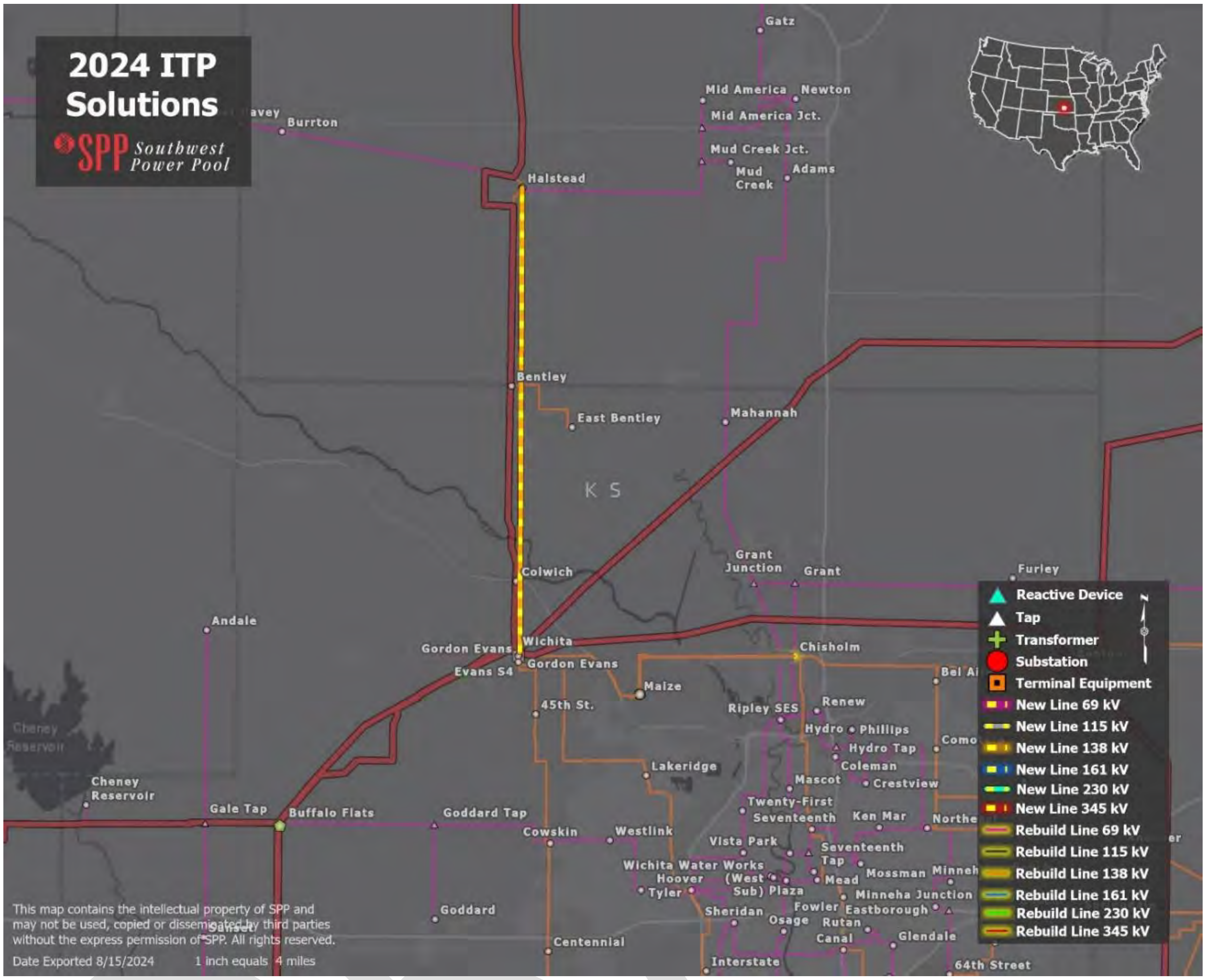

Figure 6.10: EKC: Evans Energy Center North – Halstead 138 kV New Line

In Wichita, Kansas, SPP staff observed congestion on the 138 kV line from Evans Energy Center to Colwich for the loss of the 345 kV line from Reno to Wichita. The observed congestion remains steady in year five and year 10, validating the need to resolve the congestion. SPP staff recommends resolving this congestion by building a new 138 kV line from Evans Energy Center to Halstead to provide an additional 138 kV north to south path parallel to the congested branch.

6.1.5.5 EDWARDSVILLE 161/115 KV TRANSFORMER (PERSISTENT OPERATIONAL)

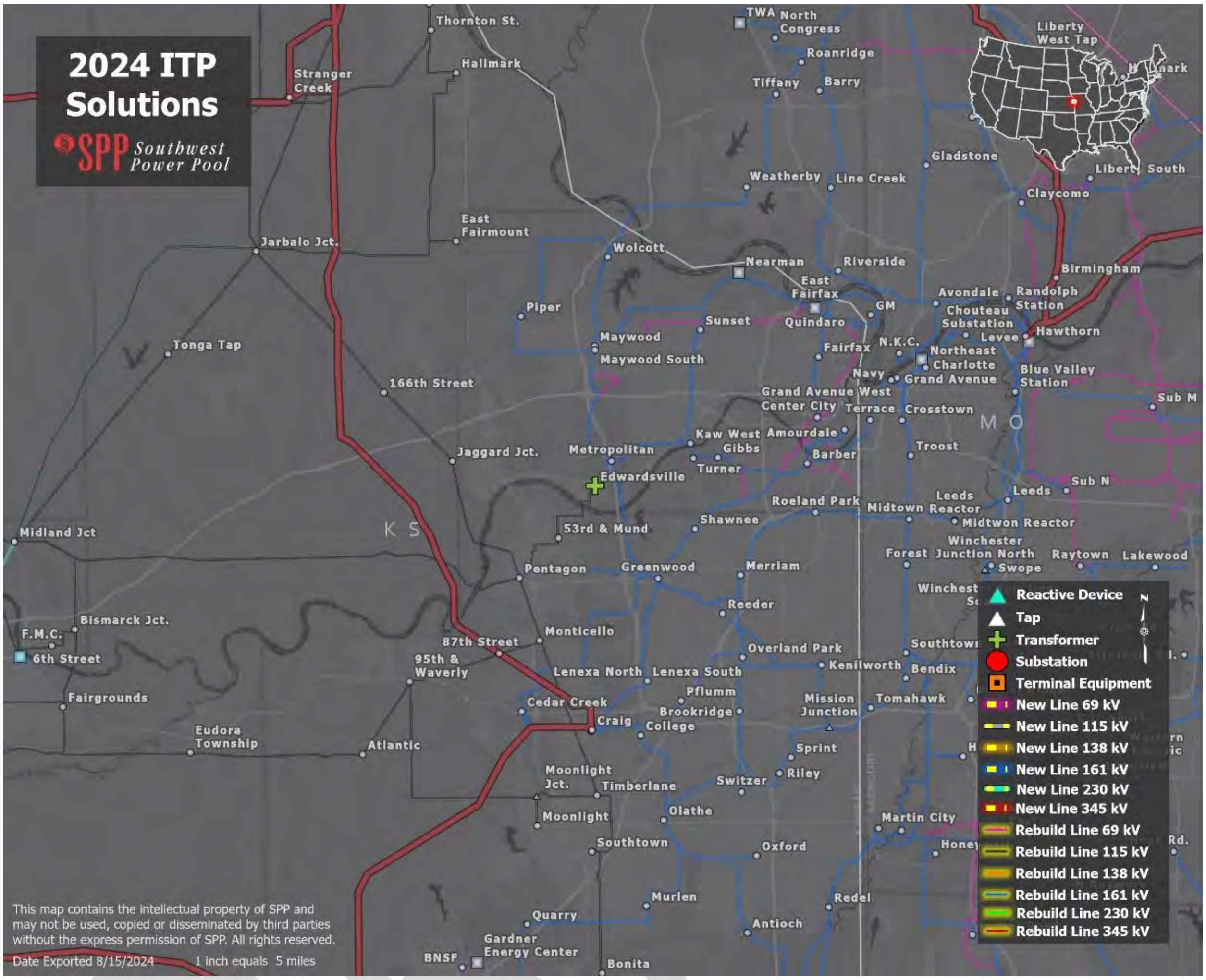

Figure 6.11: EKC: Edwardsville 161/115 kV Transformer

On the west side of Kansas City, SPP has observed congestion in real time on the Edwardsville 161/115 kV transformer for the loss of the 345 kV line from 87th Street to Craig. Congestion costs have reached $17,979,962 over a two-year period, exceeding the $10 million in congestion costs operational need threshold. SPP recommends installing an additional 161/115 kV transformer at Edwardsville to relieve the post contingent congestion.

6.1.5.6 FARBER – SUMNER COUNTY NO. 10 BELLE PLAIN 138 KV REBUILD (ECONOMIC)

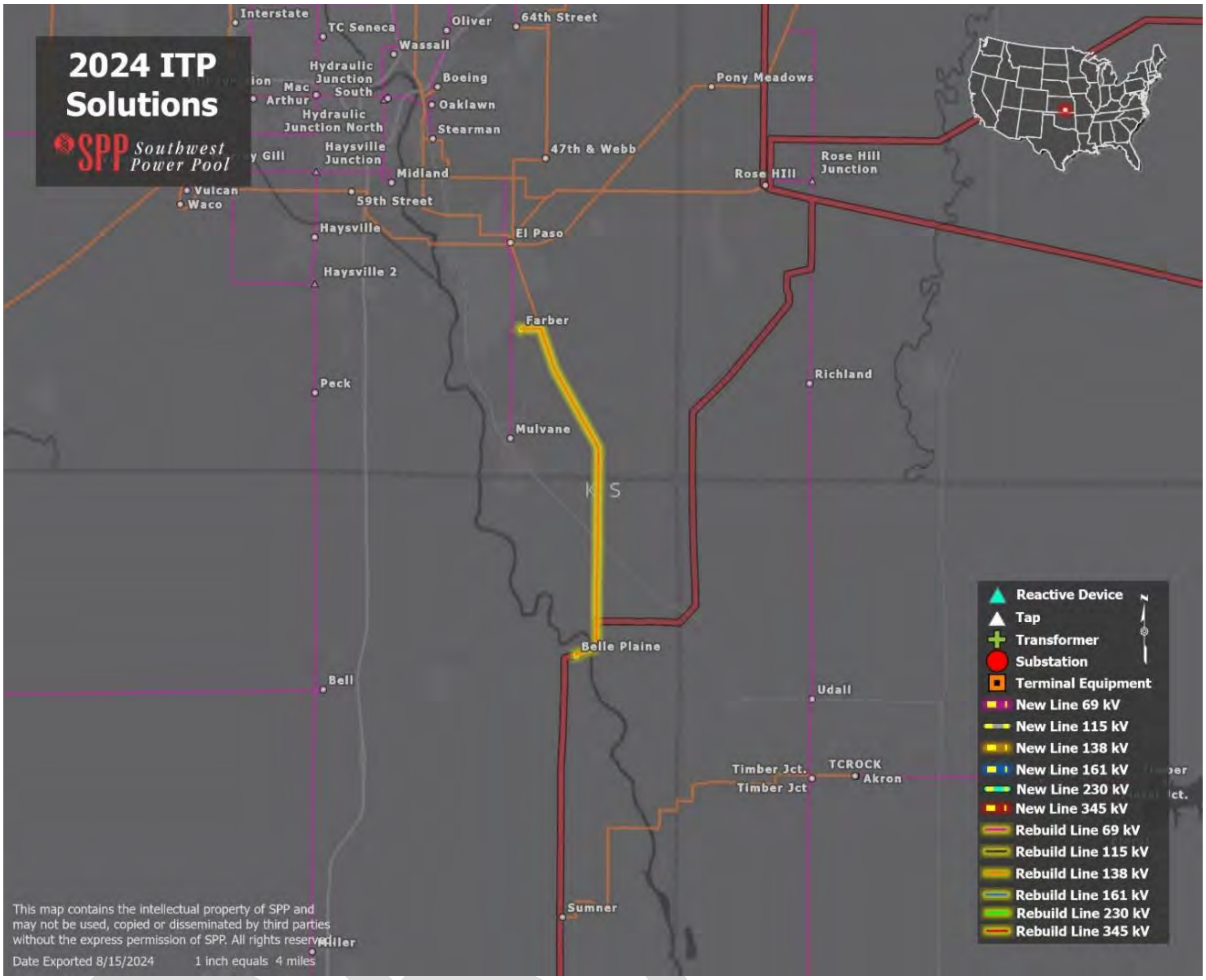

Figure 6.12: EKC: Farber – Sumner County No. 10 Belle Plain 138 kV Rebuild

Just south of Wichita, Kansas, the 138 kV line from Farber to Sumner County No. 10 Belle Plain experiences congestion for the loss of the 345 kV line from Wichita to Viola and for the loss of the 138 kV line from Middleton Tap to Peckham Tap. SPP observed that congestion that worsened from year five to year 10 and that was higher in Future 1 than in Future 2. To relieve this congestion, SPP recommends rebuilding the 138 kV line from Farber to Sumner County No. 10 Belle Plain.

6.1.5.7 LAWRENCE ENERGY CENTER UNIT 3 – LAWRENCE HILL 115 KV REBUILD (RELIABILITY/ECONOMIC)

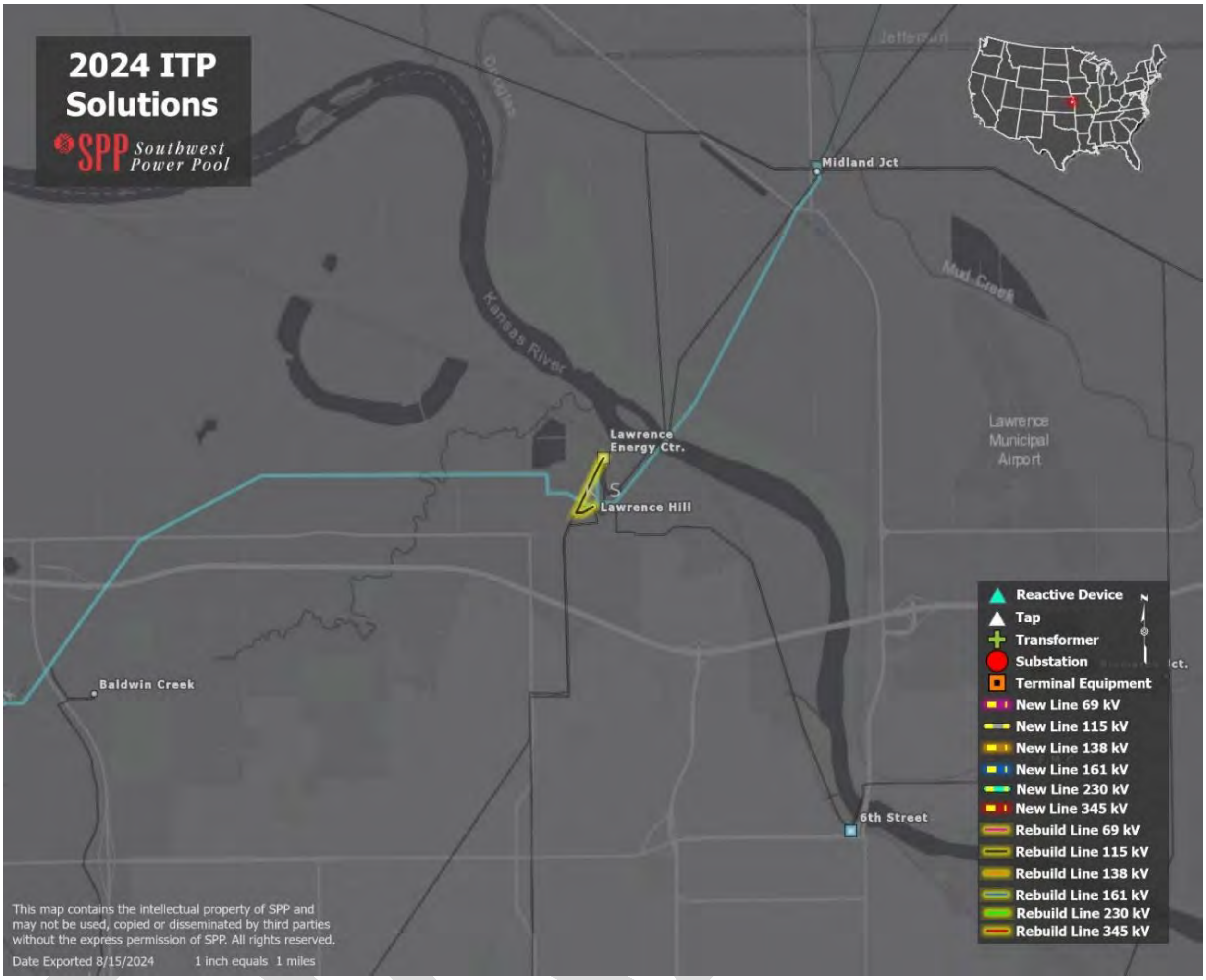

Figure 6.13: EKC: Lawrence Energy Center Unit 3 – Lawrence Hill 115 kV Rebuild

Along the eastern border of Kansas, just east of Topeka, the 115 kV line from Lawrence Energy Center to Lawrence Hill experiences congestion for the loss of the 230/115 kV transformer at Lawrence Hill. This congestion escalates in year 10 in both futures. Under the same contingency, SPP also observed a 120% thermal overload on the 115 kV line from Lawrence Energy Center to Lawrence Hill in year 10. To address this thermal overload and resolve all congestion on the 115 kV line from Lawrence Energy Center to Lawrence Hill, SPP recommends rebuilding the 115 kV line from Lawrence Energy Center to Lawrence Hill. This would increase the capacity beyond what the existing line is able to provide.

6.1.5.8 *BLACKBERRY – NEOSHO 345 KV REBUILD (ECONOMIC)*

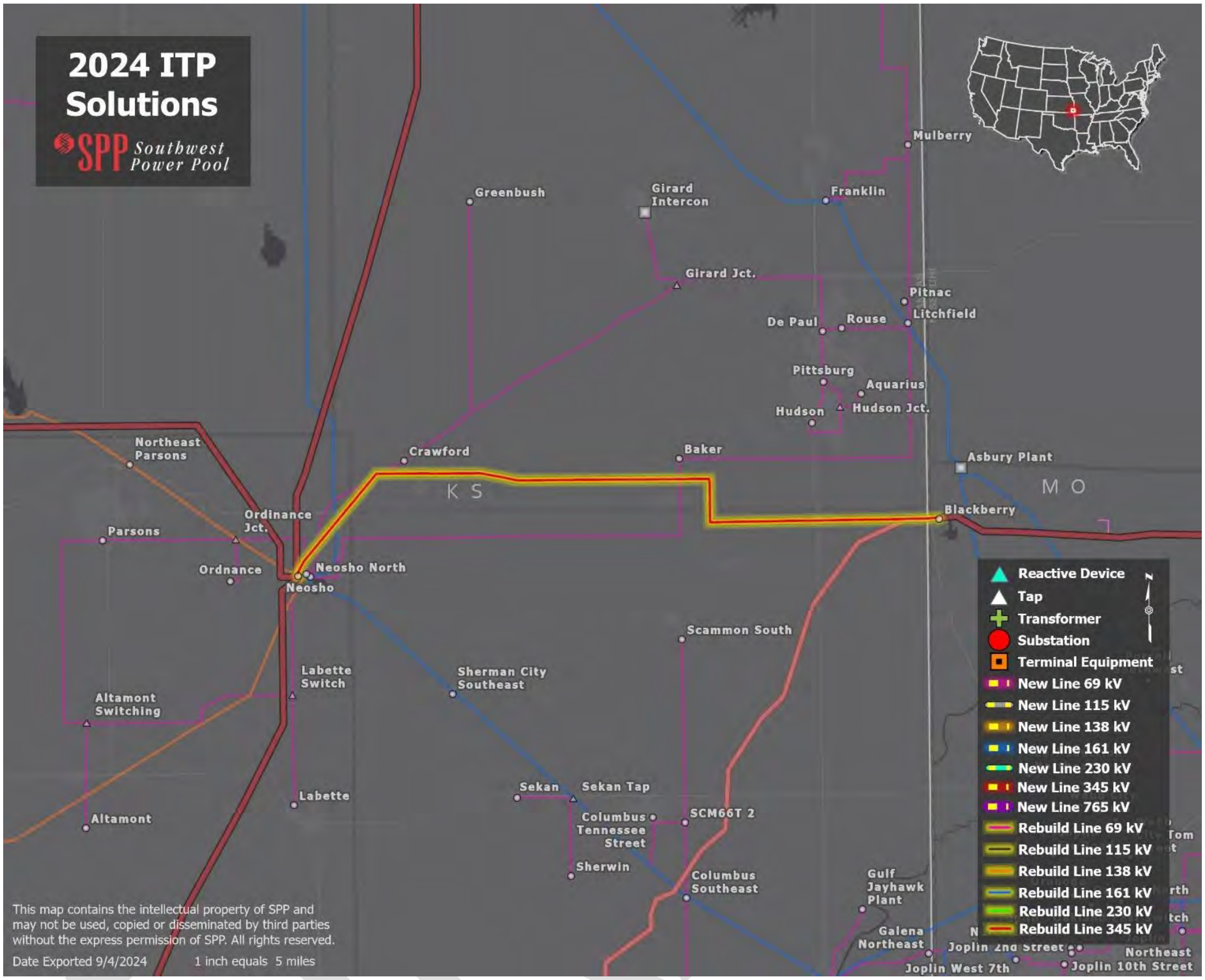

Figure 6.14: EKC: Blackberry – Neosho 345 kV Rebuild

In the southeast corner of Kansas, the 345 kV line from Blackberry to Neosho experiences west to east congestion for the loss of the 345 kV line from Blackberry to Wolf Creek. To address this congestion, SPP recommends rebuilding the 345 kV line from Blackberry to Neosho to a higher capacity. In addition to resolving post-contingent congestion, this project works together with SPP's recommendation to install a second 161/69 kV transformer at Lamar to support and facilitate increased west to east system flows. Rebuilding the 345 kV line from Blackberry to Wolf Creek also contributes to system resiliency in Missouri by supporting downstream flows that can increase during extreme winter weather events.

6.1.6 EVERGY METRO (EM)

6.1.6.1 *NASHUA 345/161 KV CKT 2 TRANSFORMER (ECONOMIC/PERSISTENT OPERATIONAL)*

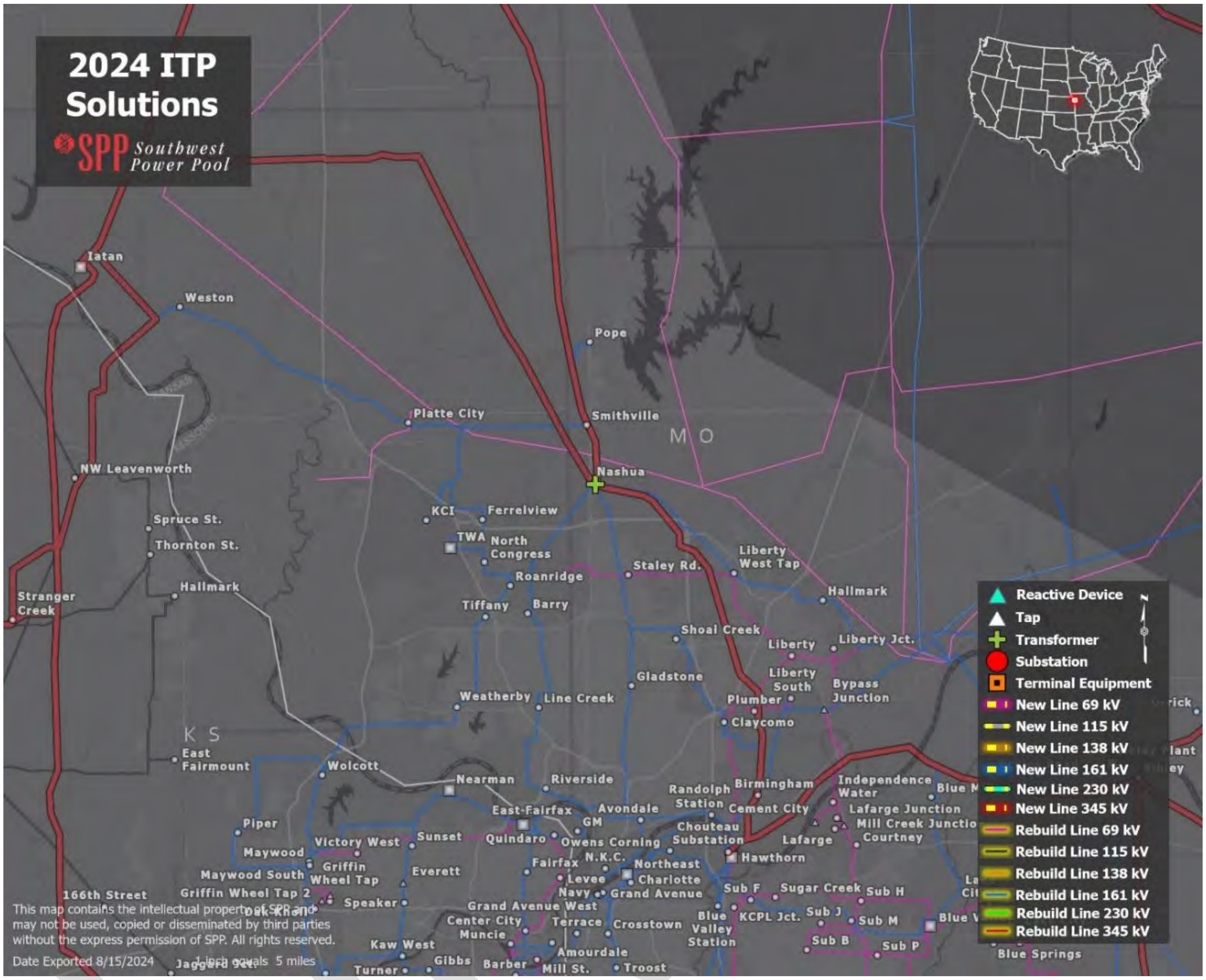

Figure 6.15: EM: Nashua 345/161 kV Transformer Ckt 2

On the north side of Kansas City, Missouri, the Nashua 345/161 kV transformer becomes congested for the loss of the 345 kV line from Hawthorne to Nashua to accommodate the additional flows that result from this contingency. This transformer was identified as a persistent operational need because of the high economic cost seen in real-time. SPP recommends installing a second Nashua 345/161 kV transformer to serve the growing load in Kansas City. The congestion was also very high in the year five and year 10 economic models, confirming the value added by SPP's recommendation to address this need.

6.1.7 GRAND RIVER DAM AUTHORITY (GRDA)

6.1.7.1 *CATOOSA 161/138 KV TRANSFORMER (ECONOMIC)*

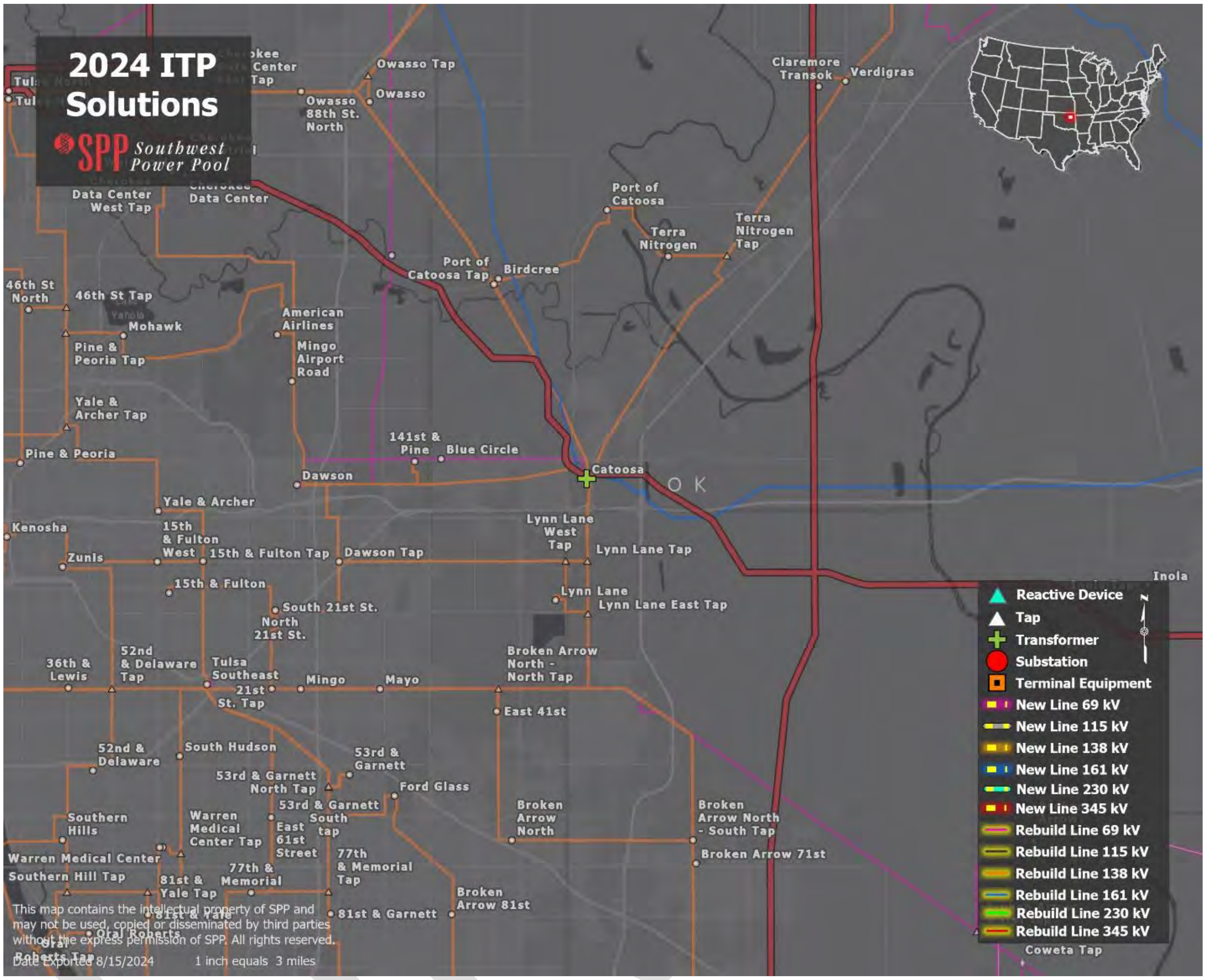

Figure 6.16: GRDA/AEP: Catoosa 161/138 kV Transformer

On the east side of Tulsa, Oklahoma, SPP observed substantial congestion on the 161/138 kV transformers at Catoosa when either of the two transformers is out of service. There is already a third transformer that is normally open. SPP requested to switch in the third transformer, but further discussion with GRDA determined the best solution would be a small rebuild of the substation to add a new bus tie to the AEP side of Catoosa to support the third transformer.

6.1.8 NEBRASKA PUBLIC POWER DISTRICT (NPPD)

6.1.8.1 *ANTELOPE – HOLT COUNTY 345 KV NEW LINE (ECONOMIC)*

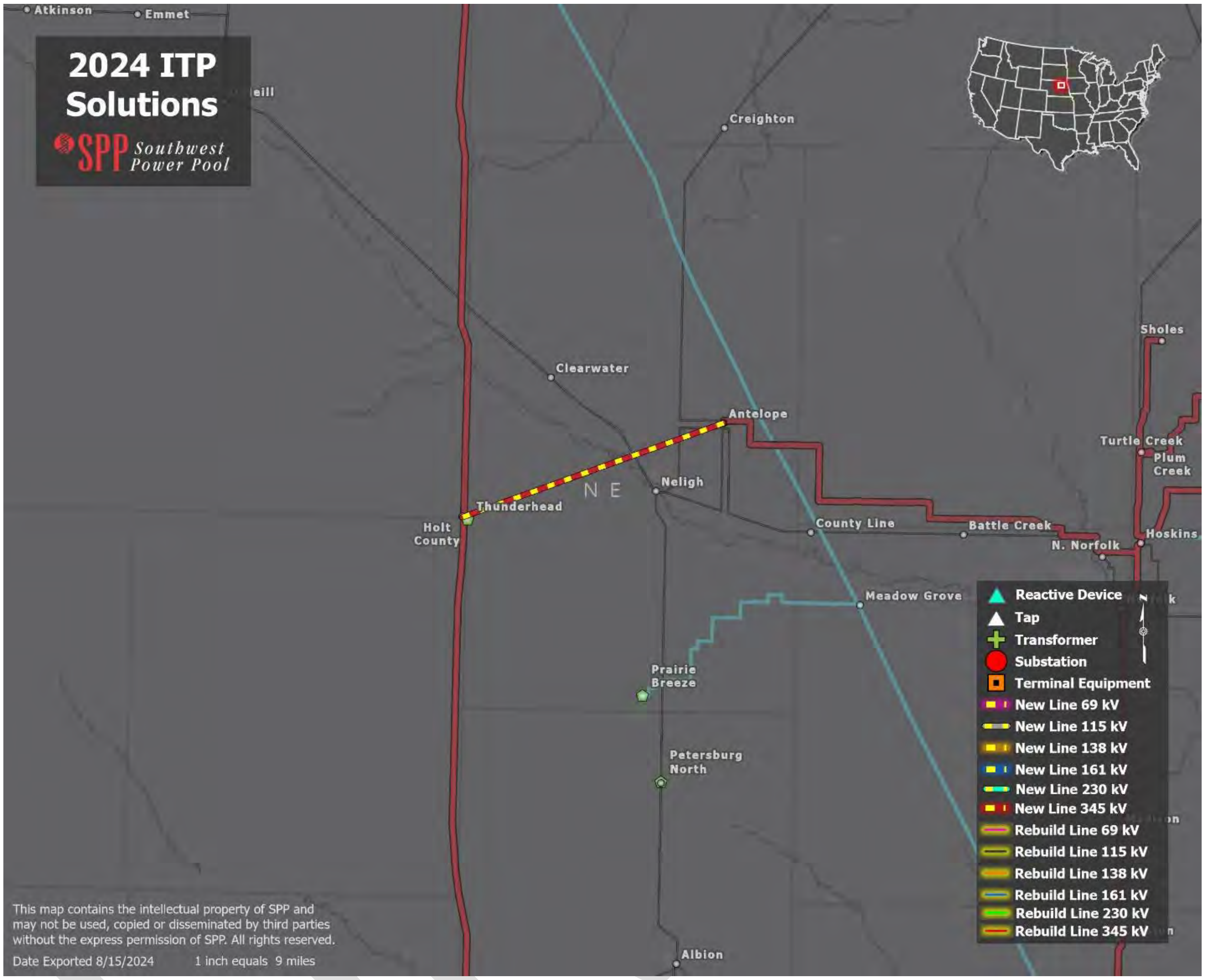

Figure 6.17: NPPD: Antelope – Holt County 345 kV New Line

In northeast Nebraska, the loss of the Ainsworth to Bassett 115 kV line causes congestion on the O'Neil to Spencer to Ft. Randall 115 kV circuit. The loss of the Hoskins to Shell Creek 345 kV line causes congestion on the Columbus to Creston 345 kV line. A new 24-mile 345 kV line from Holt County to Antelope facilitates west to east flows and relieves both cases of congestion. It has a 2.32 and 3.95 40-year benefit to cost ratio in Futures 1 and 2, respectively.

6.1.8.2 HOSKINS – STANTON NORTH 115 KV REBUILD (ECONOMIC)

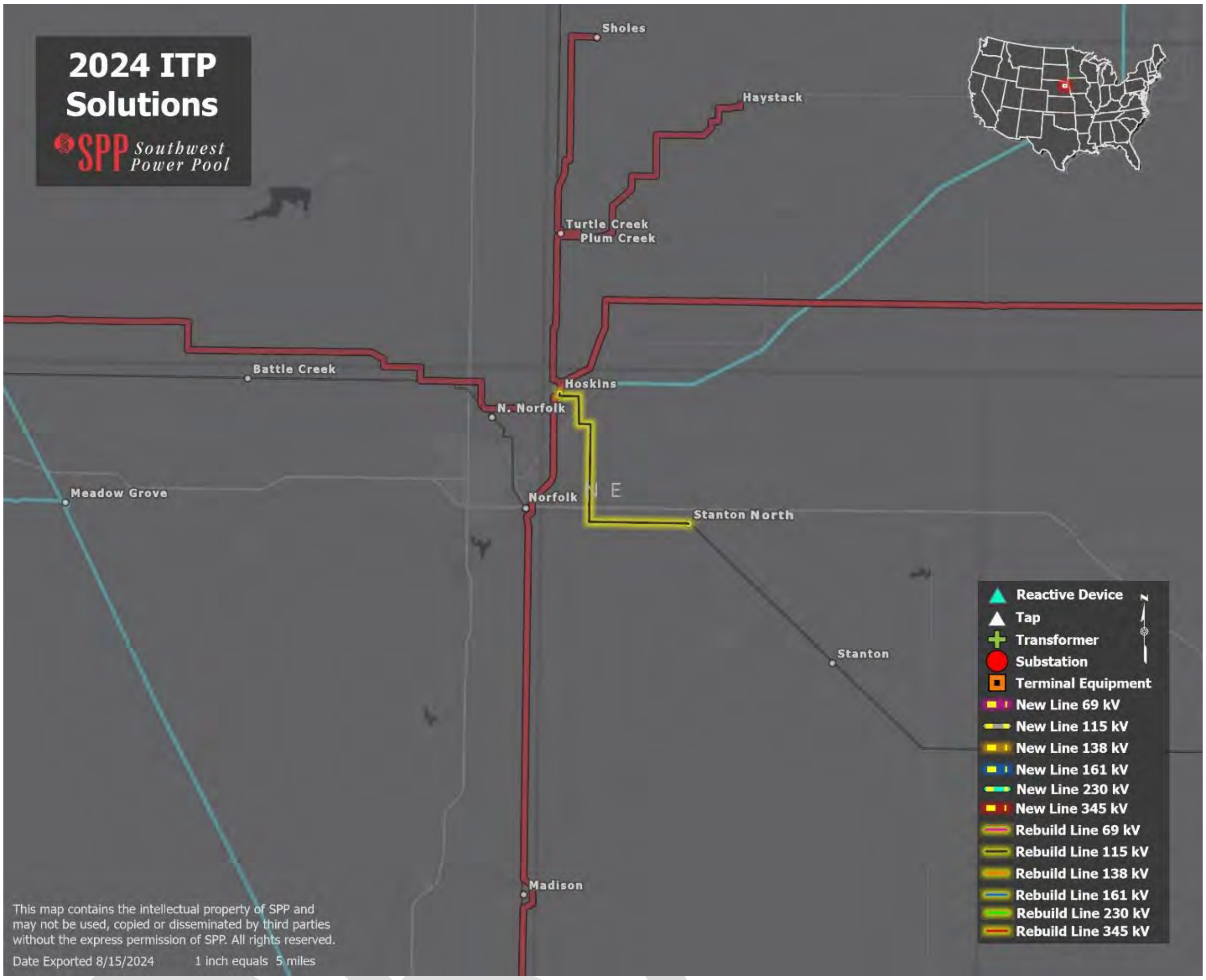

Figure 6.18: NPPD: Hoskins – Stanton North 115 kV Rebuild

In northeast Nebraska, the loss of the Raun to Hoskins 345 kV line causes congestion on the Hoskins to Stanton North 115 kV line. In both Future 1 and Future 2, the congestion score is more than eight times higher in year 10 than in year five. A rebuild of the Hoskins to Stanton North 345 kV line would resolve the congestion completely in both futures.

6.1.8.3 *AINSWORTH WIND – BASSETT 115 CKT 1 KV NEW LINE (RELIABILITY)*

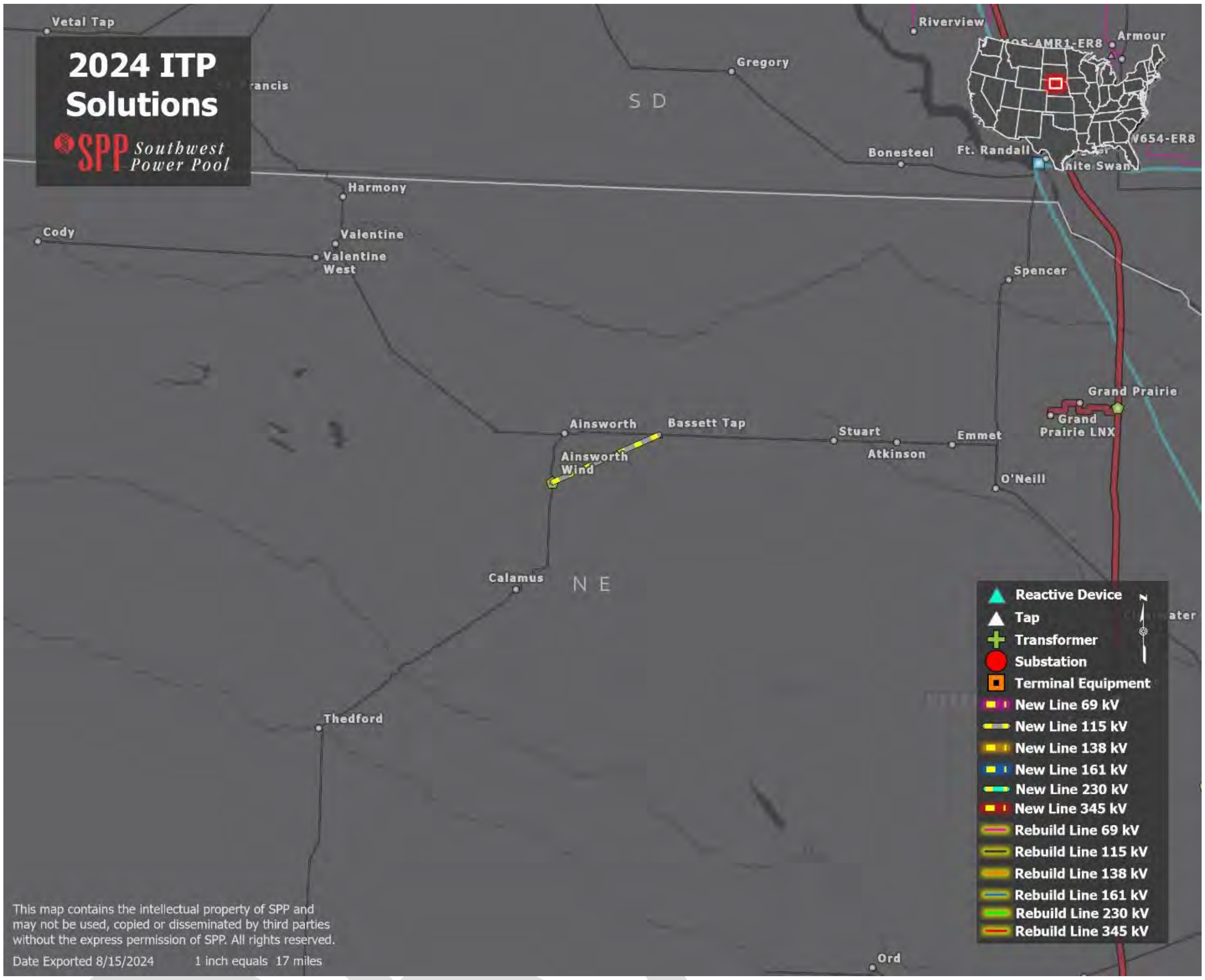

Figure 6.19: NPPD: Ainsworth – Bassett 115 kV New Line

In north-central Nebraska, the loss of the Ainsworth Wind to Ainsworth 115 kV line causes low voltage on the 115 kV branch from Ainsworth to Stuart. SPP staff recommends a new 115 kV line from Ainsworth Wind to Basset Tap, as it would provide an alternate path for support voltage in the event of an outage of the Ainsworth Wind to Ainsworth 115 kV line.

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6.1.8.4 AURORA – CENTRAL CITY 115 KV NEW LINE (RELIABILITY)

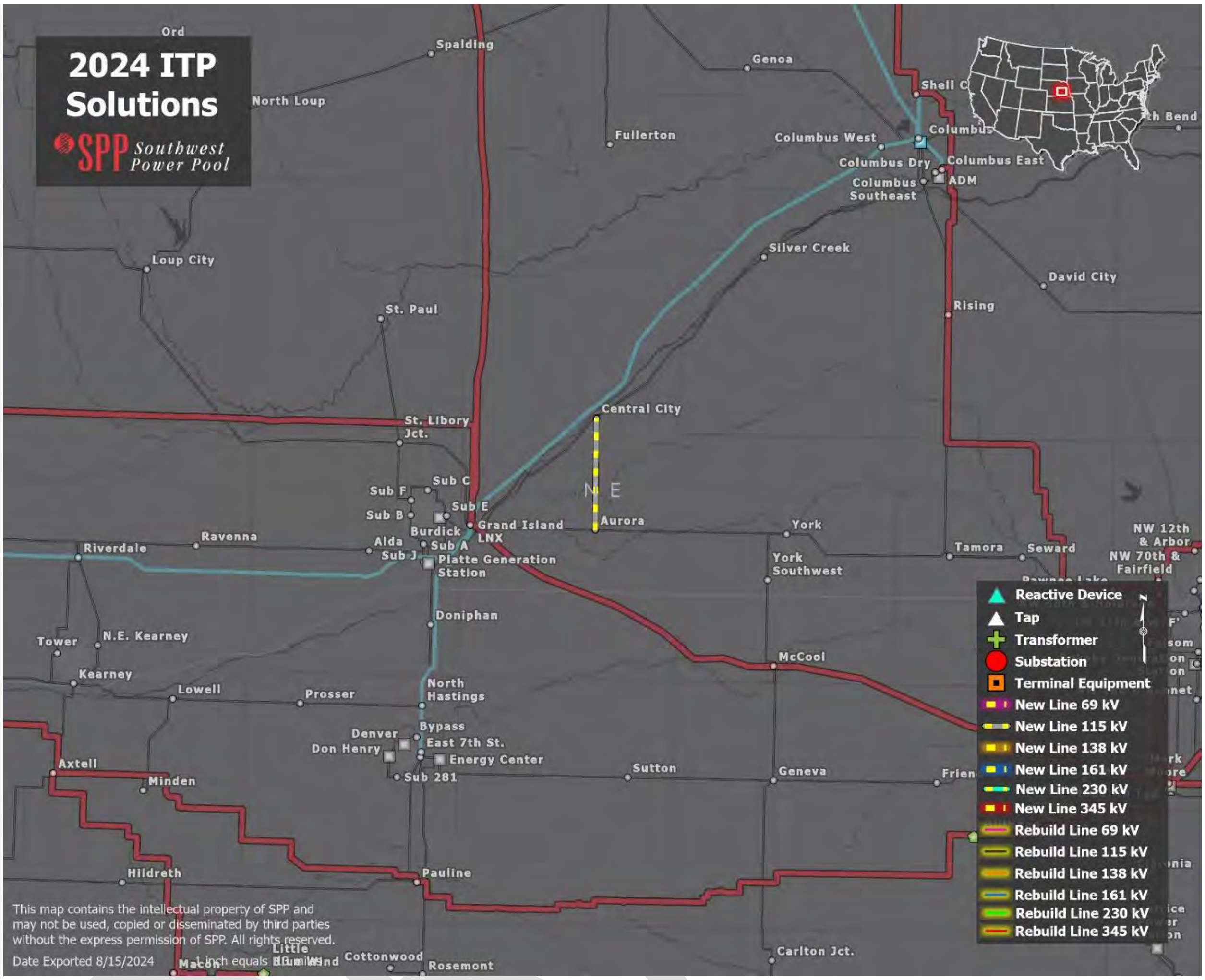

Figure 6.20: NPPD: Aurora – Central City 115 kV New Line

Northeast of Grand Island, Nebraska, the loss of the Grand Island to Central City 115 kV line causes low voltage at Central City. A new 115 kV line from Aurora to Central City provides another source of voltage support to both substations. Above-average load growth at both substations contributes to the low voltage. The load grew by roughly 18% at Central City in the summer models from year two to year 10. The new line helps support the recent load growth at both substations as well as the anticipated future load growth.

6.1.9 OKLAHOMA GAS AND ELECTRIC (OGE)

6.1.9.1 *BROWN – COLBERT 138 KV TERMINAL UPGRADE (RELIABILITY)*

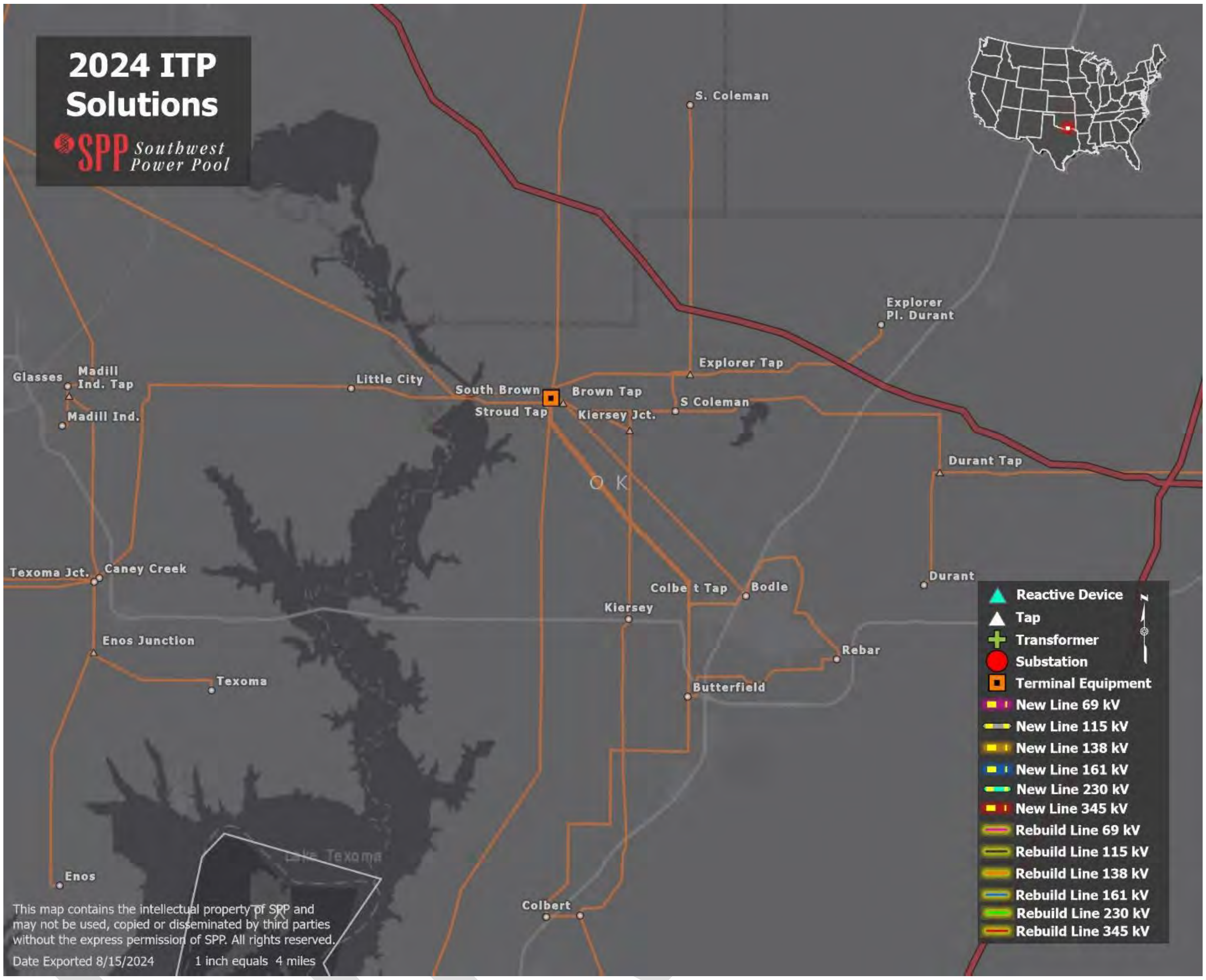

Figure 6.21: OGE: Brown - Colbert 138 kV Terminal Upgrade

The South Brown to Colbert 138 kV line is in southern Oklahoma just 20 miles north of the Texas border near Lake Texoma. The line becomes thermally overloaded in the year 10 summer model for the loss of Brown Tap to Bodle 138 kV line. The loss of the parallel lines causes a significant increase in loading on the monitored element. To resolve the overload, staff selected a terminal equipment upgrade at the Brown 138 kV substation. The terminal upgrade was selected for its low cost and ability to resolve the thermal overload by substantially increasing the rating of the monitored line capacity.

6.1.9.2 *MAUD TAP 138 KV TERMINAL UPGRADE (ECONOMIC)*

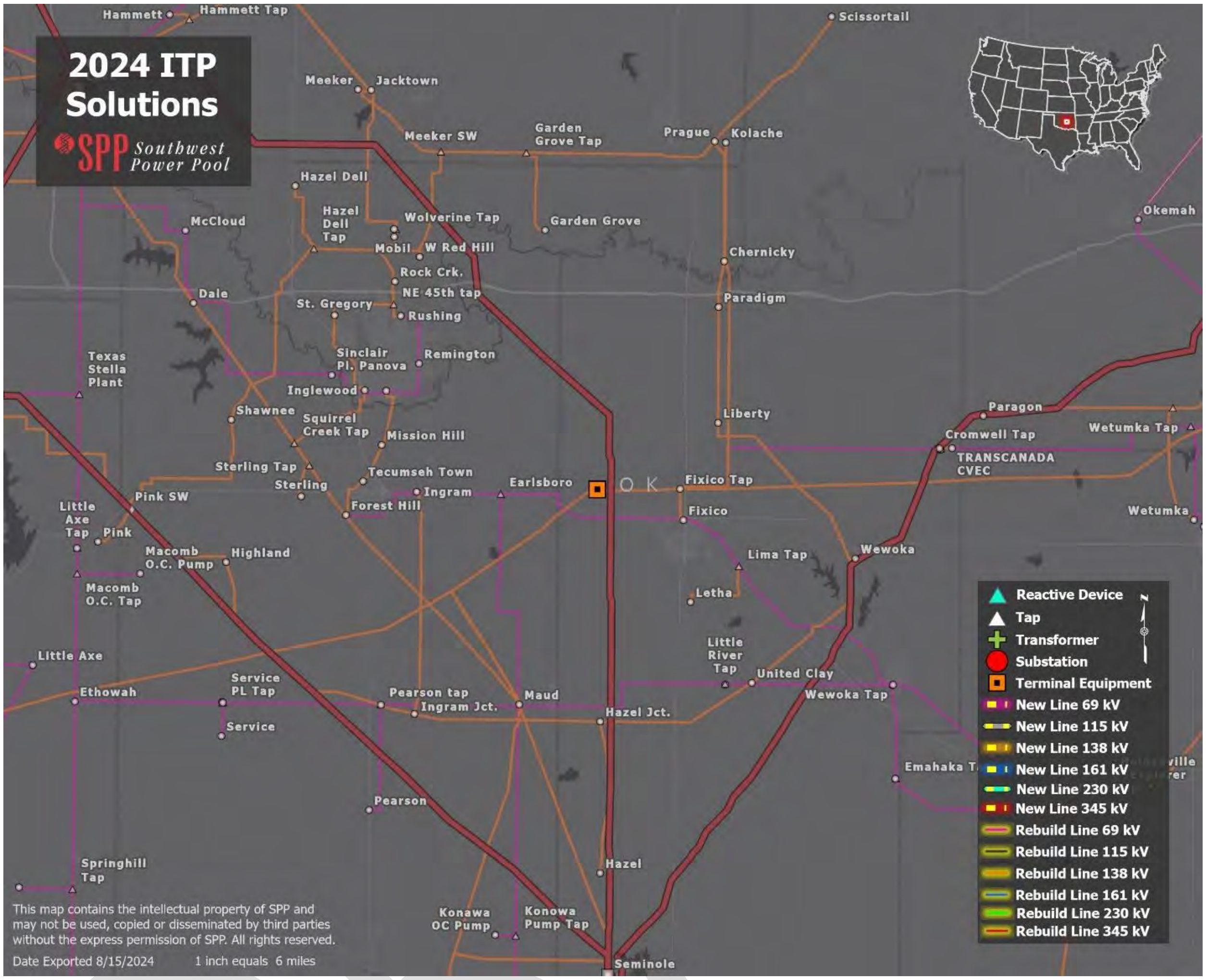

Figure 6.22: OGE: Maud Tap 138 kV Terminal Upgrade

Located approximately 40 miles southeast of Oklahoma City, the Earlsboro to Maud 138 kV line becomes congested for the loss of the Pittsburg to Seminole 345 kV line. To mitigate the congestion when the flows from the 345 kV system are shifted onto the 138 kV system, staff selected a terminal upgrade that consists of upgrading terminal equipment at the Maud Tap substation. This project was deemed the most appropriate project to resolve congestion due to its low cost and high congestion relief provided.

6.1.9.3 *MUSKOGEE - TAHLEQUAH 161 KV REBUILD AND MUSKOGEE - FORT SMITH 345 KV CONVERSION/NEW LINE (PERSISTENT OPERATIONAL/ECONOMIC)*

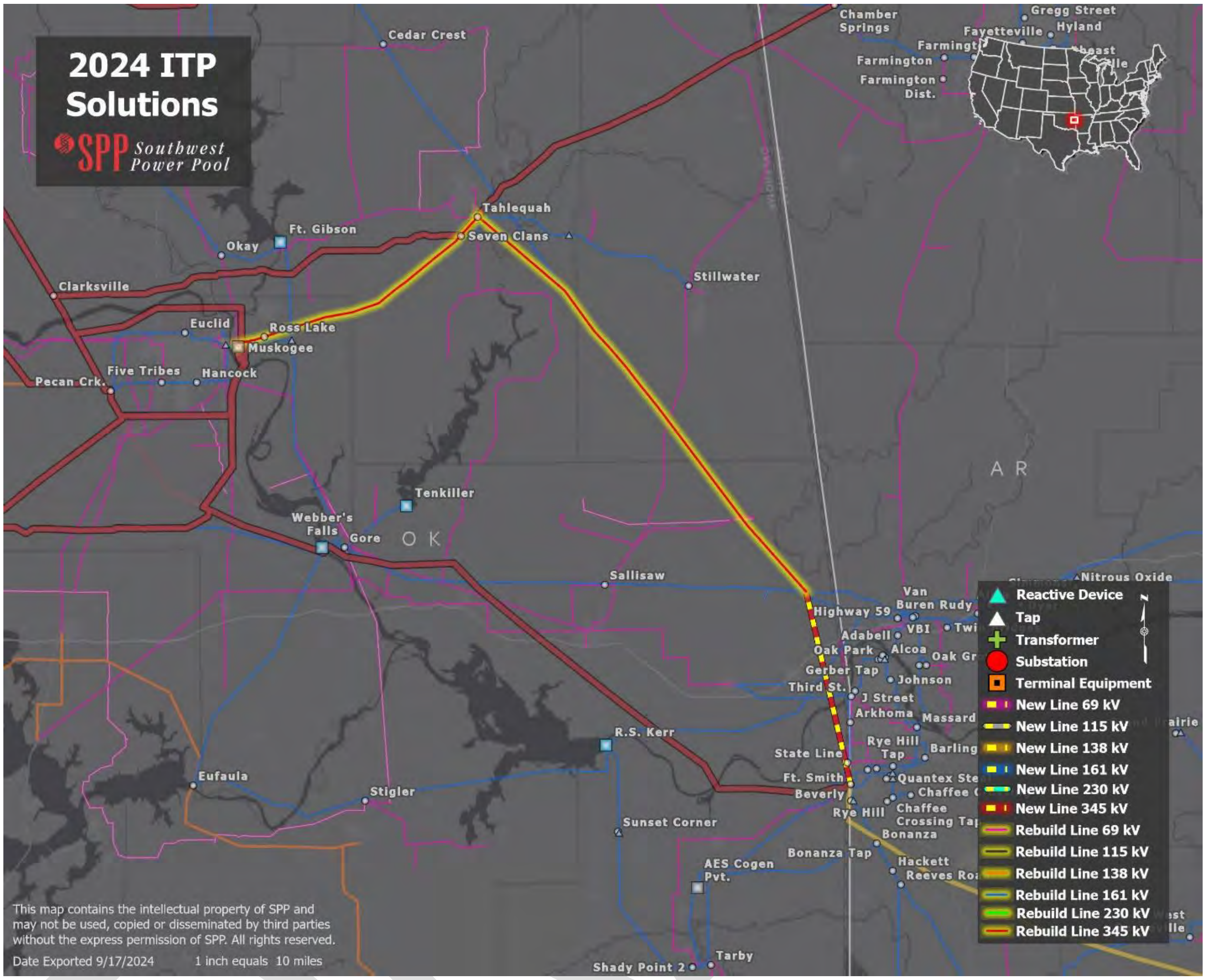

Figure 6.23: OGE: Muskogee - Tahlequah 161 kV Rebuild, Muskogee – Fort Smith 345 kV Conversion/New Line

Located along the border between Arkansas and Oklahoma, the Fort Smith 345/161 kV transformer experiences severe economic congestion for loss of the 500/345 kV transformer in the same substation. In addition, the loss of the Muskogee to Fort Smith 345 kV line creates congestion on numerous 161 kV lines between Muskogee and Fort Smith. Congestion is not only observed in the economic planning horizon, there has also been real-time historical congestion on the Tahlequah to Highway 59 161 kV line for loss of the Muskogee to Fort Smith 345 kV line for several years.

The project selected to address this congestion is a new 80-mile 345 kV line between Muskogee and Fort Smith. To reduce costs, a significant amount of existing right-of-way is used. The 23-mile 161 kV path along Muskogee - Ketowah - Seven Clans - Tahlequah will be rebuilt and add 345 kV overbuilt on the same towers. The next segment will convert approximately 43 miles of the existing Tahlequah to Highway 59 161 kV line to 345 kV, leaving the remaining portion of the existing 161 kV line open. The remaining approximately 14 miles, will be a new 345 kV path connecting to Fort Smith. And finally, a new 500/345 kV transformer will be added at Fort Smith to effectively remove the congestion observed on the existing 345/161 kV transformer.

This project was originally left out of the consolidated portfolio due to a cost estimation error. The Muskogee – Fort Smith congestion was then re-studied after aggregation of the consolidated portfolio and this project was determined to create the greatest net increase of APC benefits for the SPP region among a pool of 8 projects addressing the area. The 40-year net APC benefit is projected to be between $840 million and $1.1 billion. The project will be staged for 11/12/2024 as a persistent operational economic project due to addressing the historically constrained TAHH59MUSFTS flowgate.

6.1.10 OMAHA PUBLIC POWER DISTRICT (OPPD)

6.1.10.1 *SUB 1209 - SUB 1250, SUB 1209 - SUB 1358, AND SUB 1250 - SUB 1358 161 KV REBUILDS (RELIABILITY)*

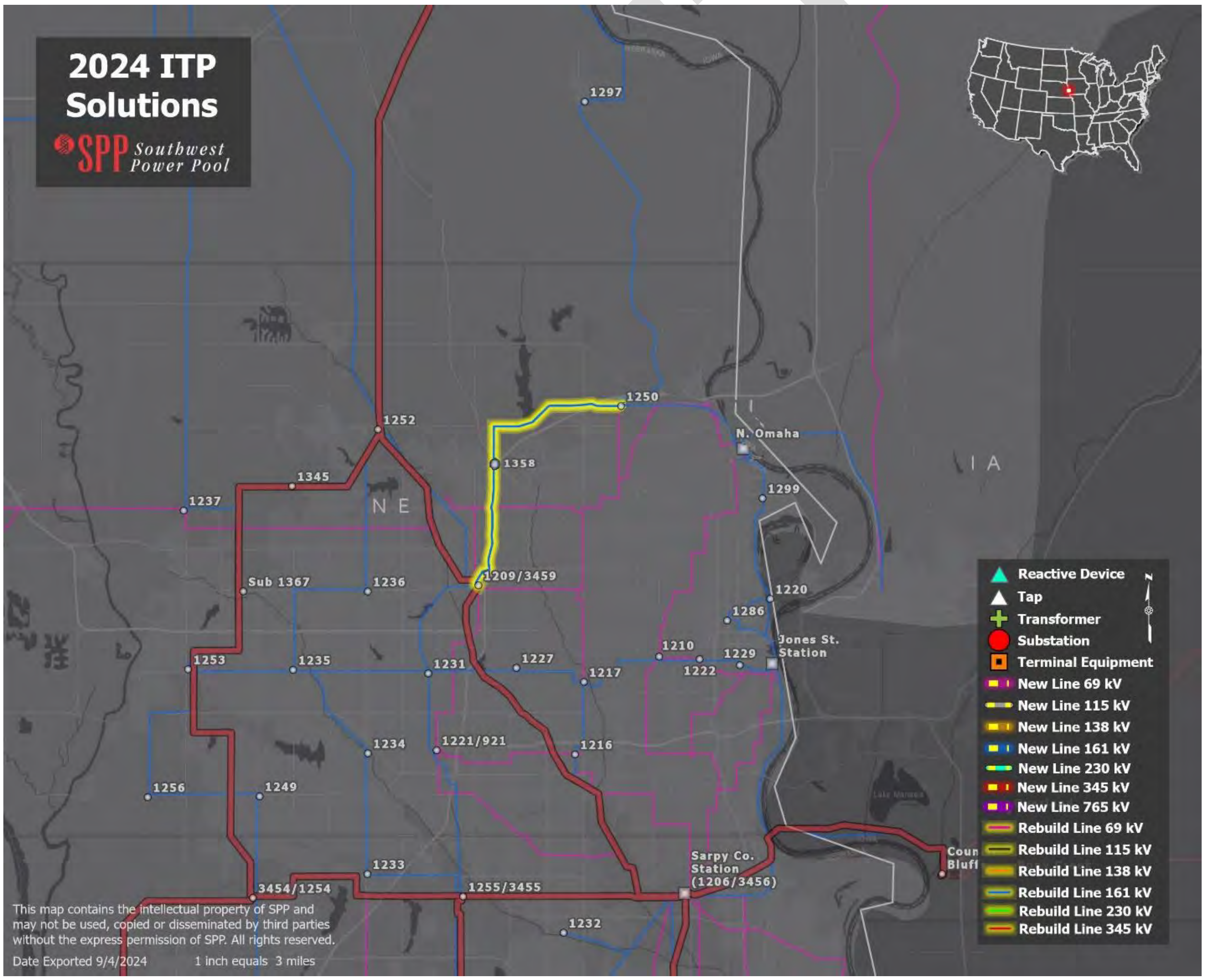

Figure 6.24: OPPD: Sub 1209 - Sub 1250, Sub 1209 - Sub 1358, and Sub 1250 - Sub 1358 161 kV Rebuilds

In the Omaha metro area of Nebraska, significant overloads are observed in the summer and winter models for year five, as well as in year 10 across all models, specifically on the 161 kV lines from S1209 to S1358 and S1250 to S1358 161 kV. A large load addition in the area is driving the overloads. The load in the area increases approximately 189% from year two to year 10 in the summer models. The load addition and overloads were originally studied in the DPA process, however no NTC was issued because there was enough lead time to evaluate alternative projects in the ITP. These overloads are the result of various contingencies, the most notable being the loss of S1251 to S1297. To address this issue, a series of projects have been proposed to alleviate the overload. These projects include the rebuilding of the Sub 1209 to Sub 1250 161 kV, Sub 1209 to Sub 1358 161 kV, and Sub 1250 to Sub 1358 161 kV lines.

6.1.10.2 *S3458 - S3740 345 KV CKT 2 NEW LINE (ECONOMIC)*

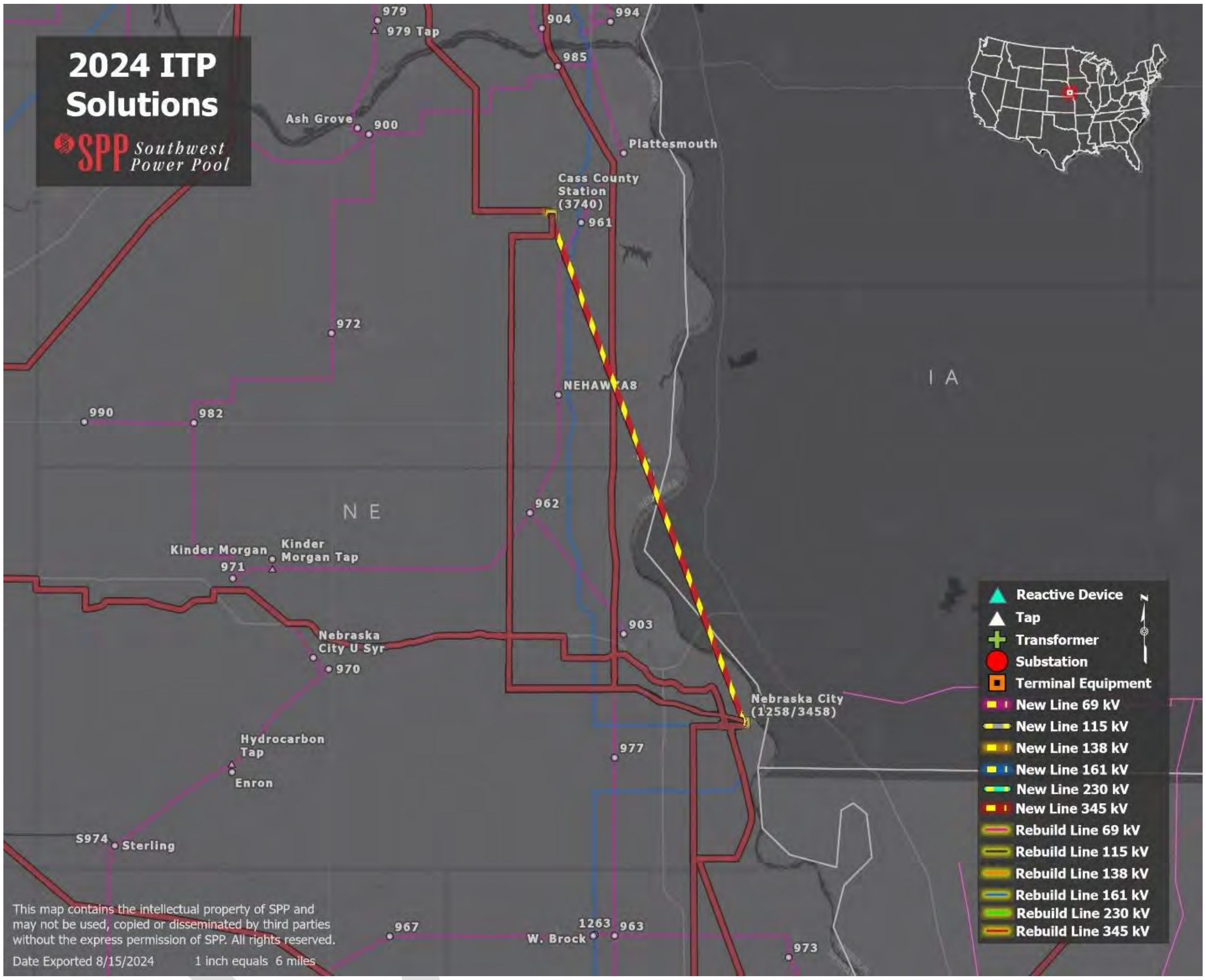

Figure 6.25: OPPD: S3458 - S3740 345 kV Ckt 2 New Line

South of Omaha, Nebraska, the 345 kV line from S3456 to S3458 becomes congested following the loss of the S3458 to S3740 345 kV line, starting in year two for Future 1 and year five for Future 2. To alleviate this congestion and drive economic benefits, SPP staff proposes constructing a second 345 kV line from S3458 to S3740. This new line would create an alternative route for the south-to-north flow of electricity from Nebraska City to Cass County, enhancing system reliability and efficiency.

6.1.11 SOUTHWESTERN POWER ADMINISTRATION (SWPA)

6.1.11.1 *BULL SHOALS – MIDWAY JORDAN 161 KV REBUILD (ECONOMIC)*

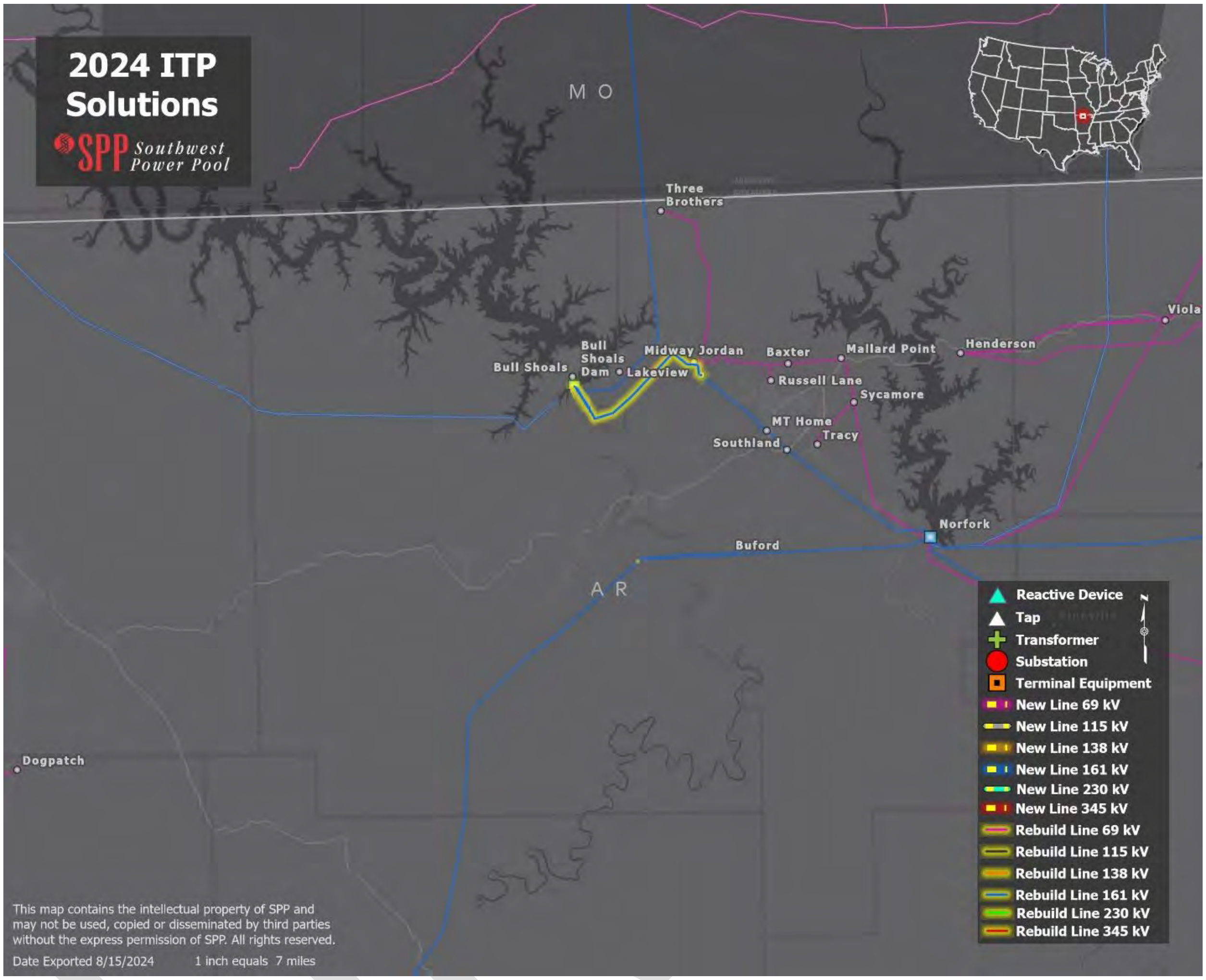

Figure 6.26: SWPA: Bull Shoals – Midway Jordan 161 kV Rebuild

Located in north Arkansas, the rebuild of the Bull Shoals to Midway Jordan 161 kV line addresses congestion that occurs on this line when the Buford to Bull Shoals 161 kV line is lost. This congestion also becomes more severe when addressing congestion in the winter storm Elliott target area. The line rebuild would completely resolve the congestion on the line and allow more economic flow of energy in the area.

6.1.12 SOUTHWESTERN PUBLIC SERVICE (SPS)

6.1.12.1 *IRON HOUSE – TEXACO 115 KV CKT 1 NEW LINE (RELIABILITY)*

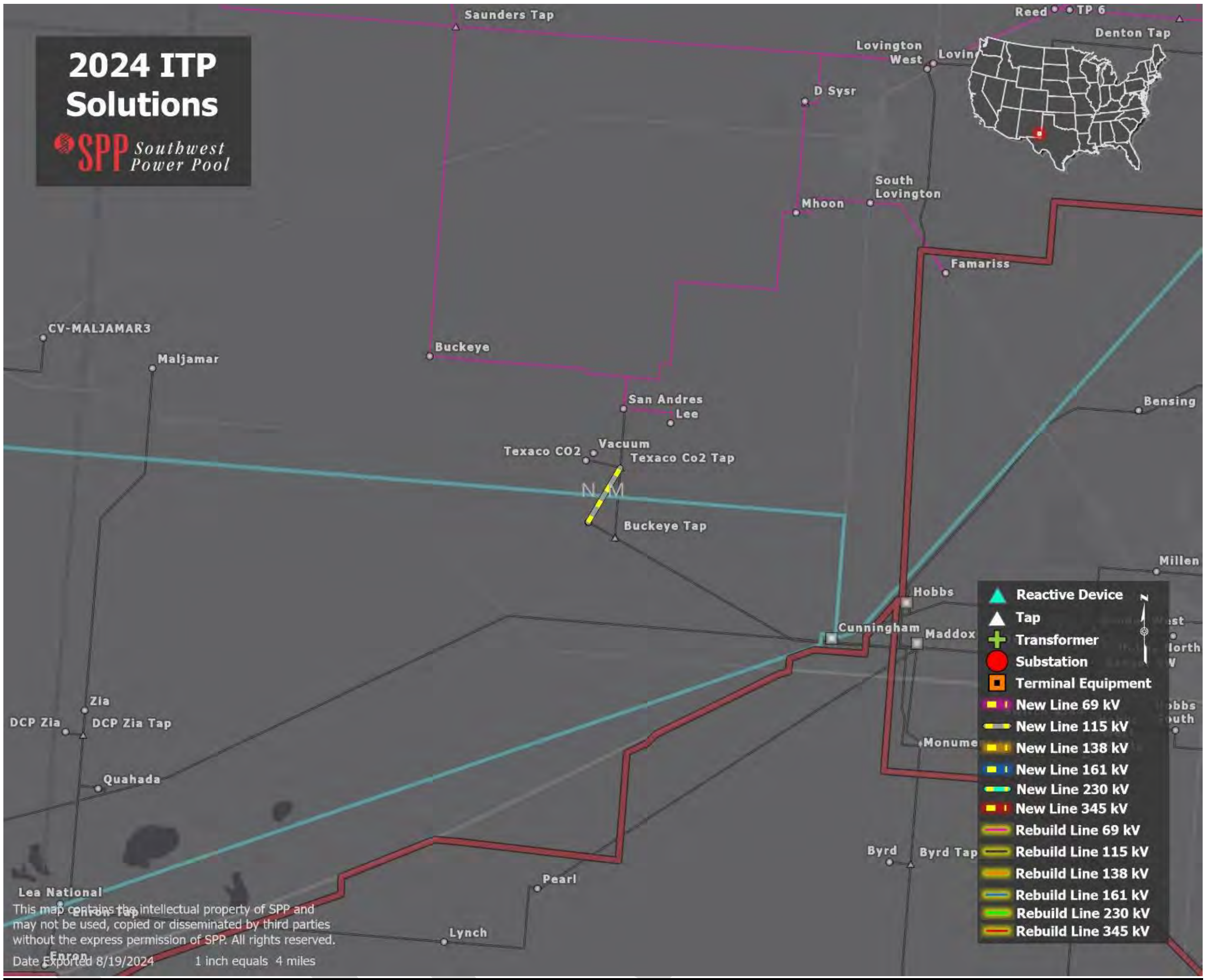

Figure 6.27: SPS: Iron House - Texaco 115 kV new line

In New Mexico, low voltage violations appear in the Texaco area in all summer models with the loss of the Iron House to Texaco 115 kV line. Adding an additional 115 kV line from Iron House to Texaco would remedy those violations, in one instance bringing the per unit voltage from 0.46 p.u. to 0.97 p.u. This line provides a secondary source to the Texaco and San Andres substations to support voltage and serve load, even with the loss of either line into Texaco from Iron House. Finally, this new line further would bolster the usefulness of the incoming line from Iron House to Cunningham tap.

6.1.12.2 *PHANTOM – CROSSROADS – POTTER 765 KV AND BECKHAM COUNTY – POTTER 345 KV NEW LINES AND TWO CROSSROADS 765 KV REACTORS (RELIABILITY/ECONOMIC)*

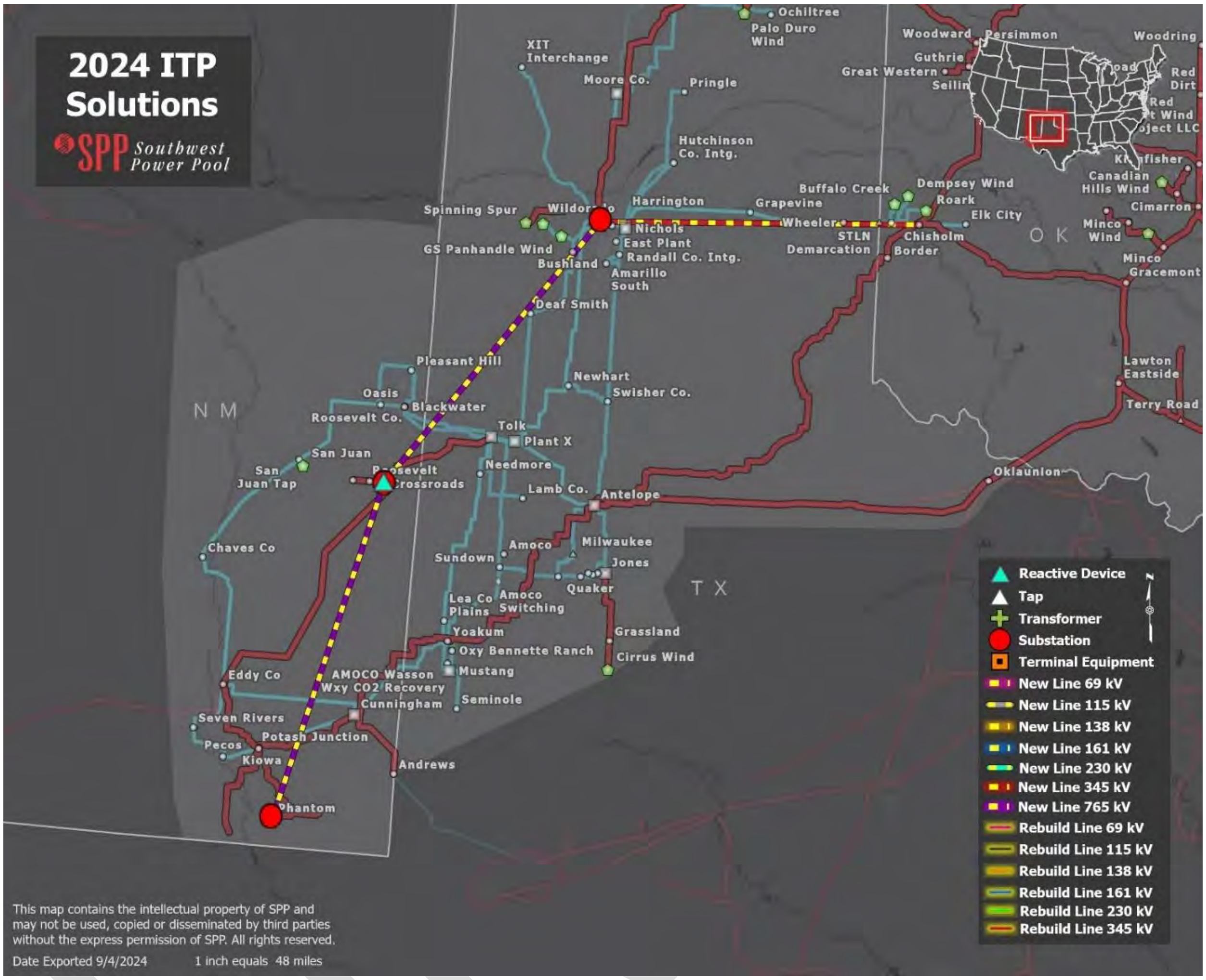

Figure 6.28: SPS/OGE: Phantom – Crossroads - Potter 765 kV and Beckham County - Potter 345 kV New Lines

As noted in the Study Drivers section, the New Mexico area is experiencing significant load growth driven by electrification of the oil and gas industry. In 2023, SPP working groups reviewed a study suggesting that an additional 5+ GW of load would be connecting in the New Mexico area.

Following the expectation outlined in the oil and gas industry support, the 2024 ITP Year 10 summer peak load in the SPS area has increased 32% from the 2023 ITP load forecast, showing the most significant growth occurring early in the planning horizon. Continuing the trend identified in the oil and gas electrification study, the loads in the SPS area for the 2025 ITP continue to grow. The following graph compares the load in the SPS area highlighting the significant load growth this area of the system is expected to see.

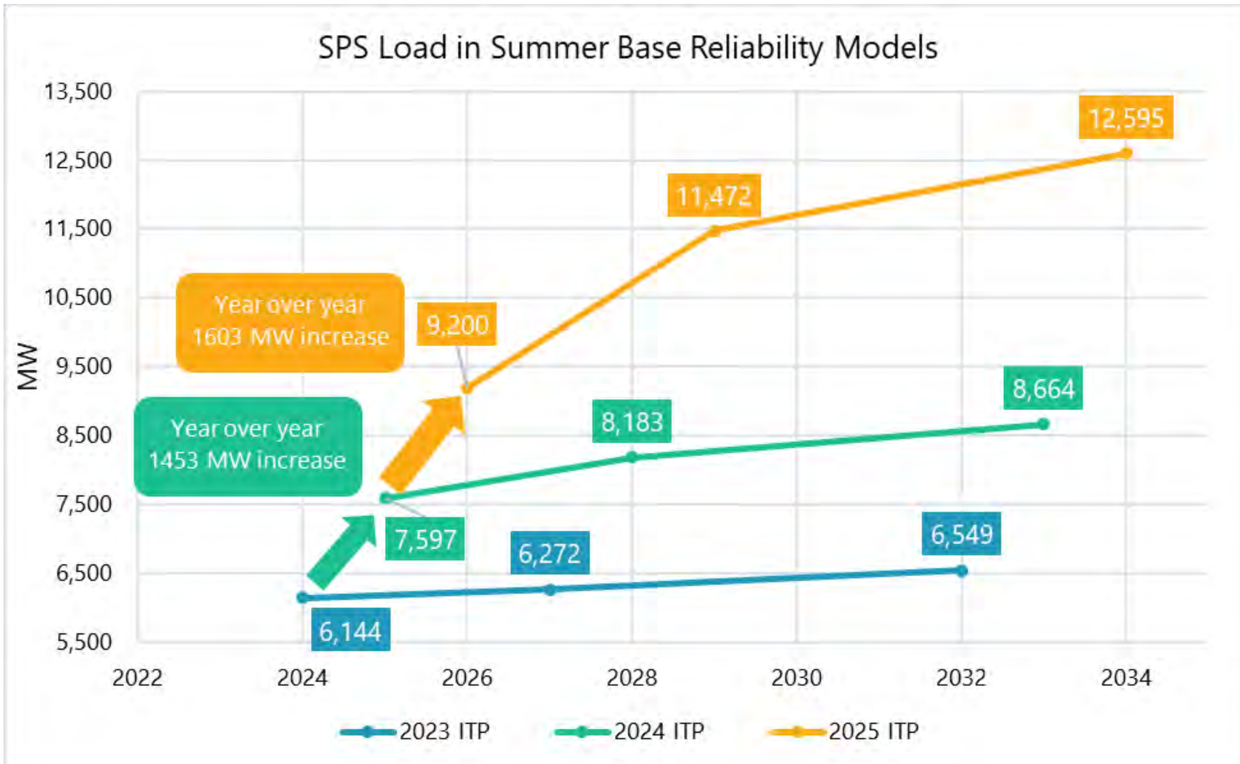

Figure 6.29: SPS Load in Summer BR Models

An additional characteristic of the SPS area is the three voltage stability interfaces identified within the system. SPP's 2021 ITP Assessment[39] described these interfaces in detail, specifically highlighting and recommending the largest project in SPP history to address the New Mexico interface (SPSNMTIES). As load has continued to grow in this area additional transmission is needed to support voltage and transfer energy through the current voltage stability interfaces. In the 2024 ITP market economic models, the New Mexico area has significant emergency energy[40] issues indicating there isn't enough transmission to deliver energy into the load pocket. The emergency energy creates large congestion costs making it one of SPP's biggest economic needs in the 2024 ITP.

In the 2024 ITP, staff originally focused on addressing the voltage collapse in New Mexico with 345 and 500 kV solutions. After considering the additional loads in the 2025 ITP, staff observed that the need for increased transfer capability into New Mexico is best solved by 765 kV infrastructure, leading to the recommendation of the Potter-Crossroads-Phantom 765 kV line. This solution is similar to the previously evaluated Potter to Tolk project because it closes the EHV gap on the west portion of the SPS system by adding a new EHV line through the middle of the SPS interfaces (SPSNorth_Sth). An

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[39] 2024 ITP Assessment Report & Addendum: https://www.spp.org/documents/66812/2021%20itp%20report%20&%20addendum%20v2.0.pdf

[40] Emergency energy is a high-cost, fictitious, segment of power each generator in the MEM has. When load is unable to be served due to the inability of the software to redispatch around a constraint, emergency energy from a generator close is utilized. SPP uses a value of $1000/MWh in its economic simulations leading to adjusted production cost increases higher than what is observed from actual energy costs.

added benefit of continuing down to Phantom is the ability to send energy directly to the bus where significant load increases have been added over the last 3 ITP studies.

Benefits of 765 kV

The benefits of 765 kV transmission are numerous and a major strategic reason the New Mexico area is the right place to begin a buildout of a 765 kV system in SPP. Some of the benefits of 765 kV infrastructure are listed below:

- 765 kV lines have nearly 3x the capacity of a 500 kV line or a double-circuit 345 kV line and 6x the capacity of a 345 kV line
- The MW-mile cost of 765 kV is less than one-third of 345 kV lines
- 765 kV transmission lines only require about half as much right-of-way (ROW) as double circuit 345 or 500 kV
- 765 kV infrastructure experiences lower line losses than lower voltage lines
- Typical tower height of 765 kV lines are 30-40 feet shorter than double circuit 345 kV
- 765 kV lines are capable of tranmitting energy over longer distances than lower voltage lines

SPP staff also recommends a new 345 kV line from Beckham County to Potter, as a necessary companion project to supply energy to the 765 kV line. The Beckham County to Potter line will act as another EHV source into the 765 kV line allowing it to move power from the panhandle of Texas to the southeast corner of New Mexico. This 345 kV line is a key piece of SPP's effort to extend EHV lines throughout the footprint to further enhance power delivery and to prepare for potential 765 kV overlay similar to the one studied in SPP's EHV Overlay Report from 2008.[41] Originally, SPP staff had selected Chisholm to Potter as the necessary 345 kV project, however the TWG and ESWG voted to change the eastern termination point of this project to Beckham County. The Beckham County – Potter project will retain the same staging date as determined for Chisholm – Potter 345 kV during the staging process.

Together the lines solve voltage collapse, economic congestion and emergency energy issues that arise in each line during 2024, bringing voltage above the minimum standards during multiple different contingency events while also reinforcing the system in preparation for the extensive load growth.

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[41] https://sppshare/sites/TransPlanning/Shared%20Documents/EHV%20Overlay%20Study/SPP_EHVProject_FinalReport.pdf

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6.1.12.3 CONWAY – KIRBY 115 KV TERMINAL EQUIPMENT (PERSISTENT OPERATIONAL)

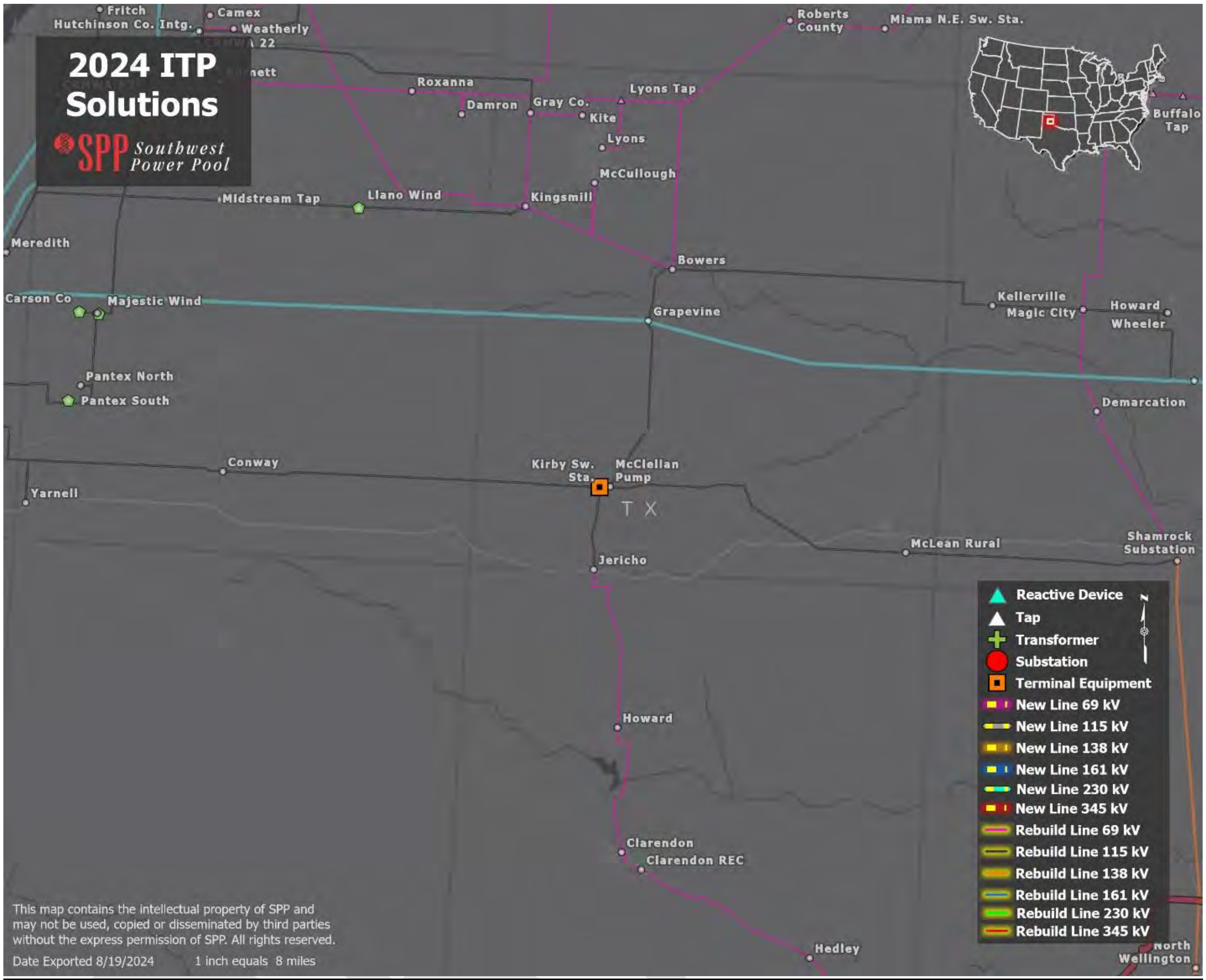

Figure 6.30: SPS: Conway - Kirby 115 kV Terminal Equipment

The Conway to Kirby 115 kV line is an operational flowgate in the panhandle of Texas. SPP's real-time operations observed over $53 million in congestion cost over the past two years on this line for the loss of the Nichols to Grapevine 230 kV line. Upgrading the terminal equipment at the Kirby 115 kV substation would relieve the congestion on the line.

6.1.12.4 *DENVER – MID AMERICA 69 KV AND SAN ANDREAS – SEMINOLE 115 KV TAP AND GAINES – RILEY – MID AMERICA – MID DENVER TAP REBUILD (RELIABILITY)*

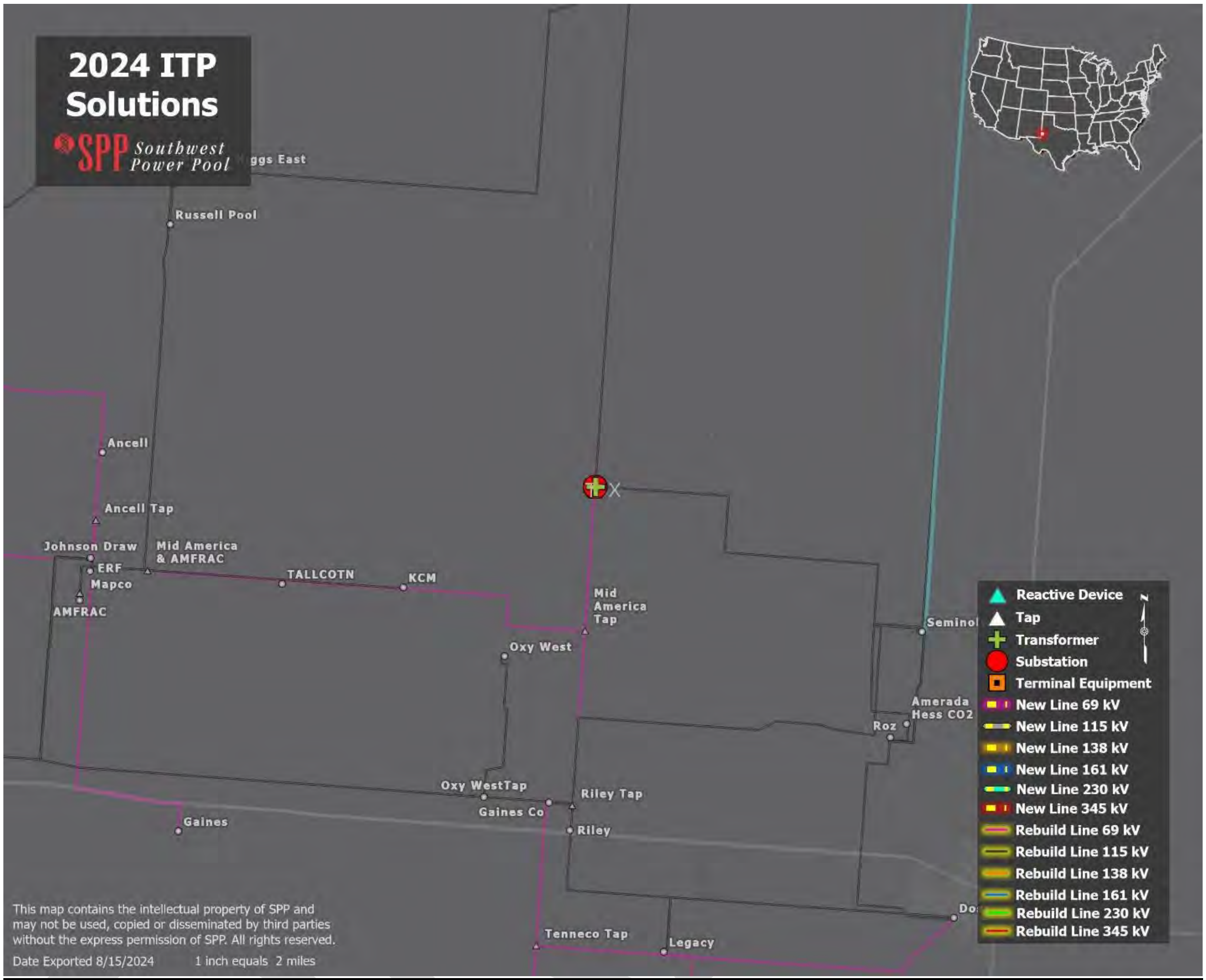

Figure 6.31: SPS: Denver - Mid America 69 kV San Andreas - Seminole 115 kV Tap

Southwest of Lubbock, Texas, the Riley and Tenneco 69 kV substations experience low voltage violations in the year two and year five scenarios for the loss of lines delivering power through Riley or Johnson Draw. For the same contingency the Gaines 115/69 kV transformer also experiences a thermal violation in all scenarios. As it exists today, the Mid America to Denver 69 kV line is out of service. SPP staff recommends tapping the Mid America to Denver 69 kV line where it intersects with the San Andreas to Seminole 115 kV line, which would energize a 2.6-mile section of the existing line from the new tap down to Mid America. Connecting the 115 and 69 kV lines creates an alternate path to the 230 kV connection at Seminole that will provide power to the 69 and 115 kV system in the Gaines area and therefore solves both voltage and thermal needs.

The final reliability assessment identified that the newly in service 2.6-mile section of 69 kV line from Mid America Tap to Mid Denver overloads in year five and year 10 summer seasons when another nearby connection to the 115 kV system is lost. When the connection is lost, the Gaines to Riley to Mid America 69 kV lines that lead up to Mid America to Mid Denver are also overloaded. Rebuilding these branches (shown in Figure 7.1), totaling 6.04 miles, would resolve the overloads under the contingency condition and increase the value of the new tap intersection.

6.1.12.5 GRAPEVINE – KINGSMILL 115 KV NEW LINE (RELIABILITY)

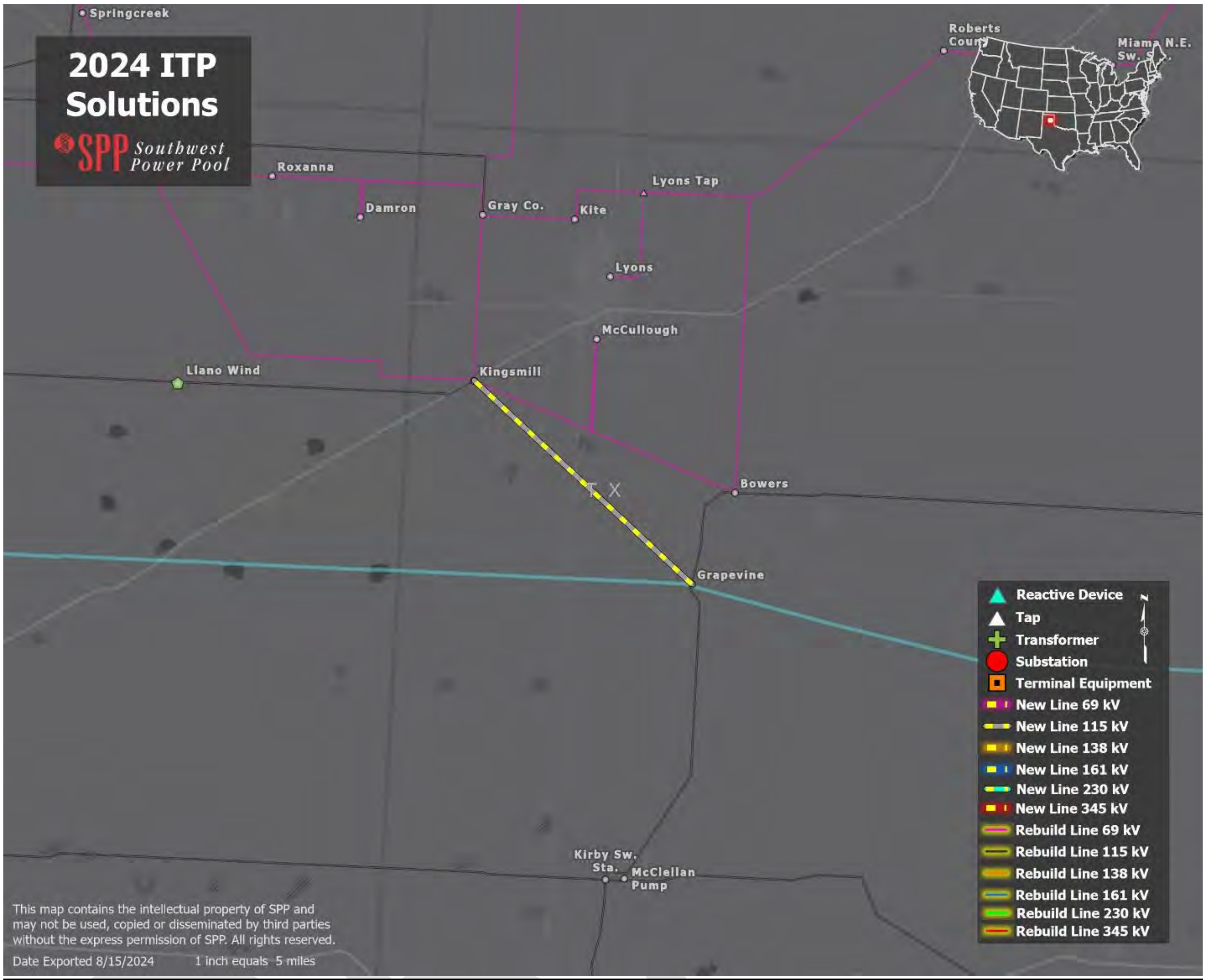

Figure 6.32: SPS: Grapevine - Kingsmill 115 kV New Line

East of Amarillo, Texas, Grapevine and Kingsmill experience low voltage issues and thermal issues arise at the Gray County and Kingsmill substations during the summer seasons when access to the power provided through Hutchinson or Meredith and Llano Wind is lost. Constructing a new 115 kV line from Grapevine to Kingsmill would deliver both voltage and thermal relief by providing another connection to the 230 kV line at Grapevine. This new line would allow the system to maintain access to adequate power delivery, even if the power flowing from Meridith or Hutchinson is interrupted, while also strengthening this 69-115 kV system for the future.

6.1.12.6 *LYNCH – MEDANOS 115 KV NEW LINE AND MADDOX – PEARLE 115 KV REBUILD (RELIABILITY)*

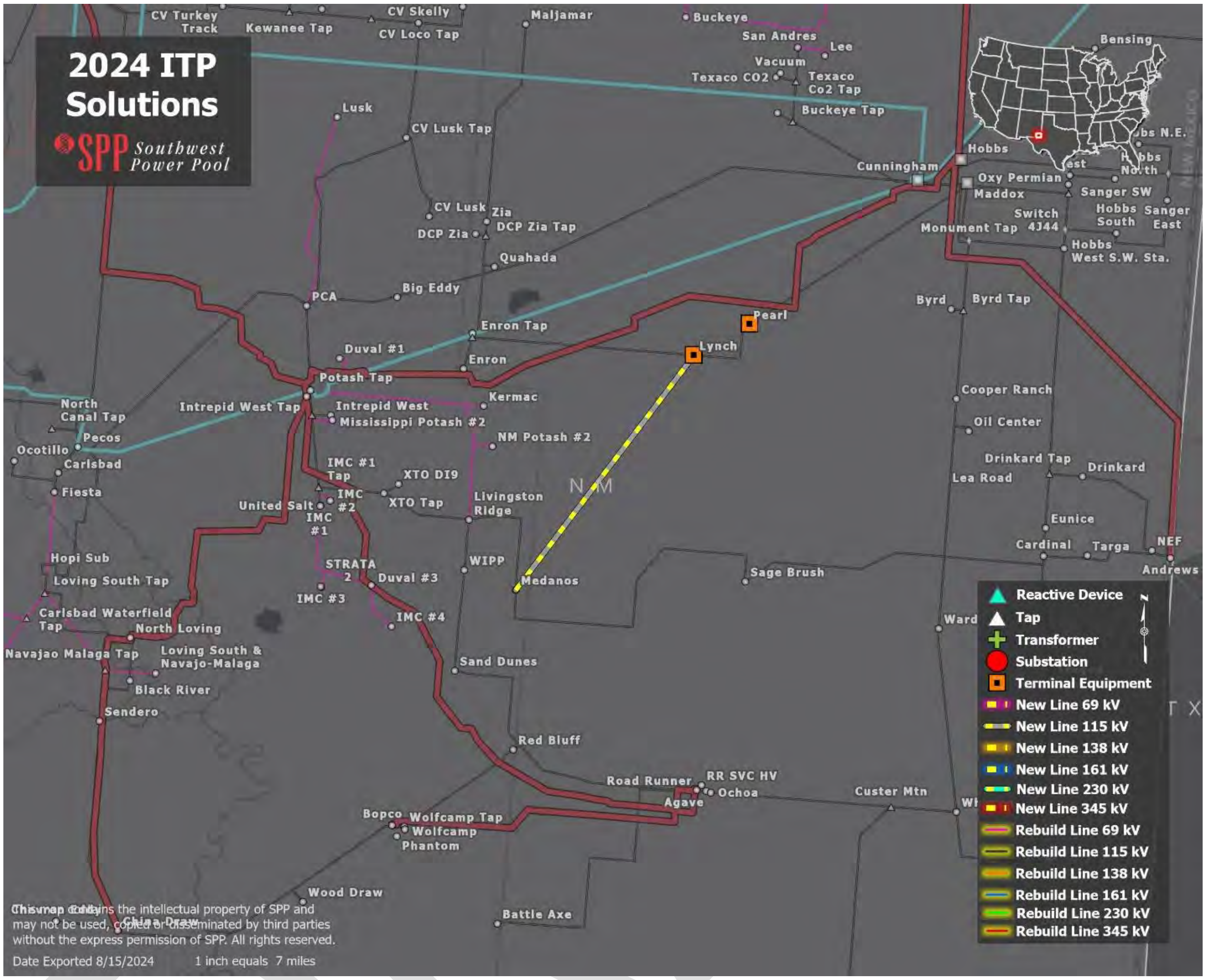

Figure 6.33: SPS: Lynch - Medanos 115 kV New Line

In southeast New Mexico, multiple voltage violations appear with the loss of the Potash Junction to Intrepid West Tap 115 kV line. Adding a new 115 kV line between Lynch to Medanos while also upgrading the terminal equipment on the Lynch to Pearl line opens another path to provide voltage support on the 115 kV system. This project would bring post-contingency violations from as low as 0.77 p.u. up to 0.92 p.u. while also bolstering the north-south transfer between Kiowa and Hobbs.

The new 115 kV line from Lynch to Medanos would, however, affect the flow on the Maddox to Pearle 115 kV line. By allowing a new outlet on the Pearle substation side of the line, more flow would route through the Maddox to Pearle 115 kV line causing an overload in year two summer when the Cunningham to Quahada 115 kV line is lost. The project selected to address the reliability violation is a rebuild of the 115 kV line from Maddox to Pearle.

6.1.12.7 *MOORE COUNTY – XIT 230 KV NEW LINE, CHANNING 230 KV 14 MVAR CAPACITOR, AND MOORE COUNTY 230/115 KV CKT 2 TRANSFORMER (RELIABILITY)*

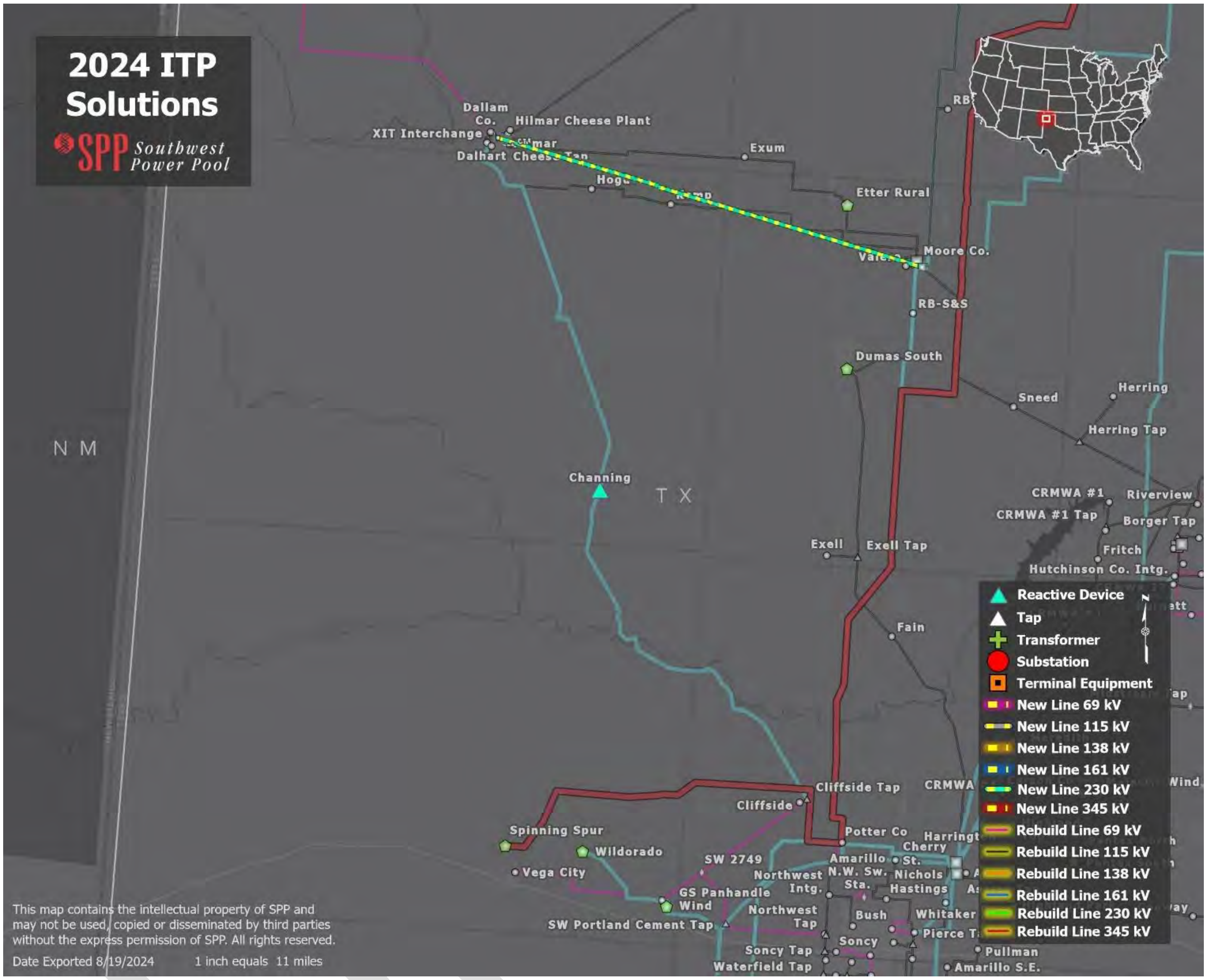

Figure 6.34: SPS: Moore County - XIT 230 kV New Line and Channing 230 kV 14 MVAR Capacitor

In the panhandle of Texas, the Moore County to XIT 230 kV new line provides much needed voltage support in the XIT area west of Moore County. This area experiences multiple voltage violations in years two, five and ten after losing the XIT transformer or either 230 kV line between XIT and Potter. With this new line added, the XIT area would have two robust 230 kV options to support the growing load in the area and allow for an alternate path for power to flow if the Moore County to Potter line is ever lost.

Similarly, voltage violations are present at Channing for the loss of the Channing to Potter County 230 kV line. Once this line is lost, the Channing substation experiences low voltage violations in all winter models, year two and year five summer models and in the year 10 light load model. Adding a 14 MVAR capacitor bank at Channing would resolve the violations and allow the substation to have ample voltage support despite its minimal transmission connections.

Both projects would assist in strengthening the SPS area and maximize the value brought about by the proposed 765 kV line from Phantom to Crossroads to Potter.

The new 230 kV line from Moore County to XIT also would resolve an overload on the Moore County 230/115 kV transformer for the loss of the Channing to Potter 230 kV line. However, due to the new connection, a contingency taking out the XIT 230/115 kV transformer now has a greater impact on the flow through the Moore County 230/115 kV transformer, causing it to again overload in the year five and year 10 summer scenarios. SPP chose a second circuit Moore County 230/115 kV transformer (shown in Figure 7.1) to address this issue identified during the final reliability assessment. The second circuit adequately shares the flow when the XIT 230/115 kV transformer is lost, preventing the violation, while also protecting against other such contingencies.

6.1.12.8 *ROADRUNNER 345/115 KV CKT 2 AND CKT 3 TRANSFORMERS (RELIABILITY/ECONOMIC)*

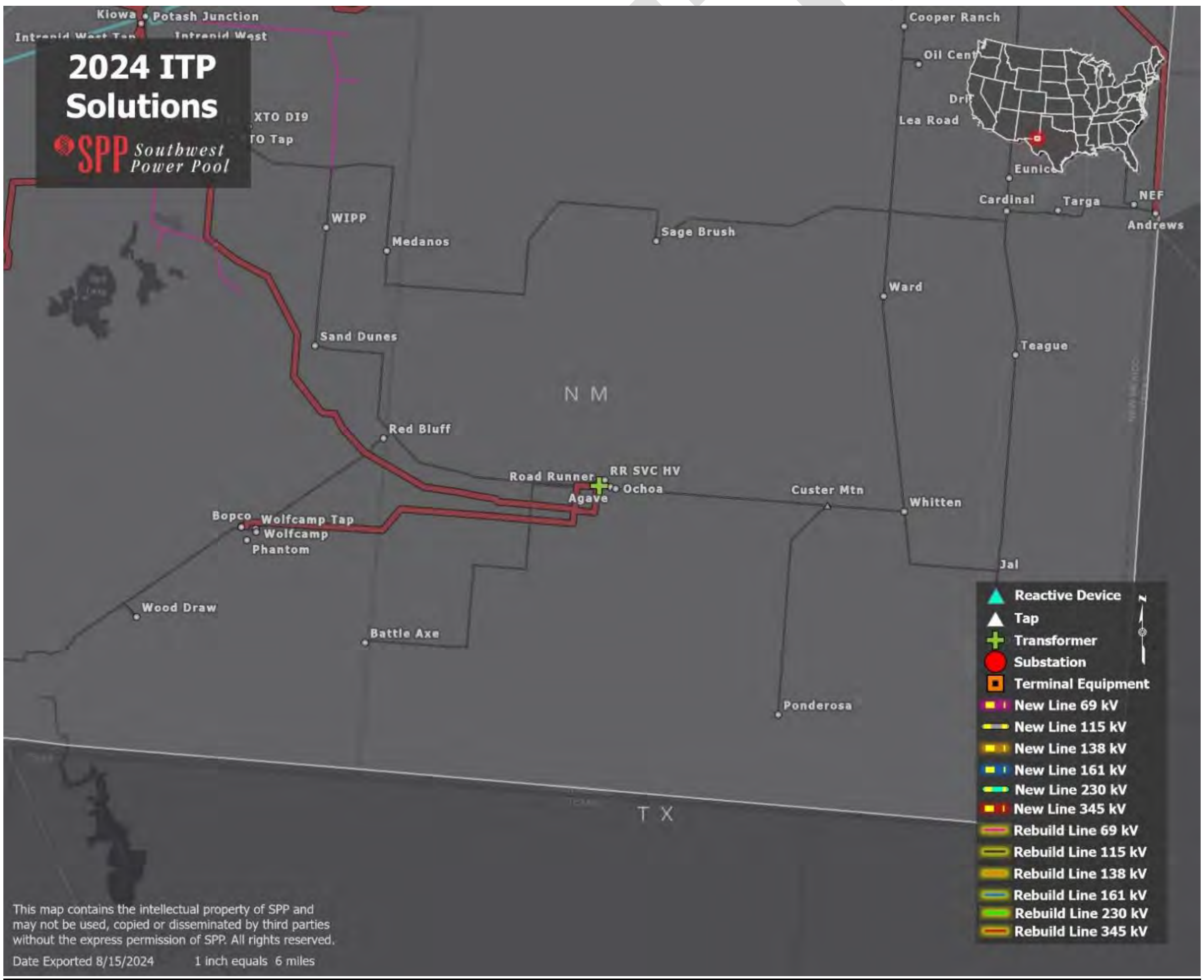

Figure 6.35: SPS: Roadrunner 345/115 kV Ckt 2 and Ckt 3 Transformers

Various contingencies in the southeast portion of New Mexico cause the Roadrunner transformer to overload in the year 10 summer model, as well as an overload in the basecase. Installing two new transformers at Roadrunner would allow for more robust power-flow and prevent overloads on any of the transformers in N-1 conditions. These transformers would also aid in controlling the effects of load growth in the area and will complement the future addition of the Crossroads to Hobbs to

Roadrunner 345 kV line to maximize its benefits. This line was recommended by the 2021 ITP and has an in-service date of May 15, 2025.

6.1.12.9 FRANKFORD – QUAKER 115 KV REBUILD (RELIABILITY)

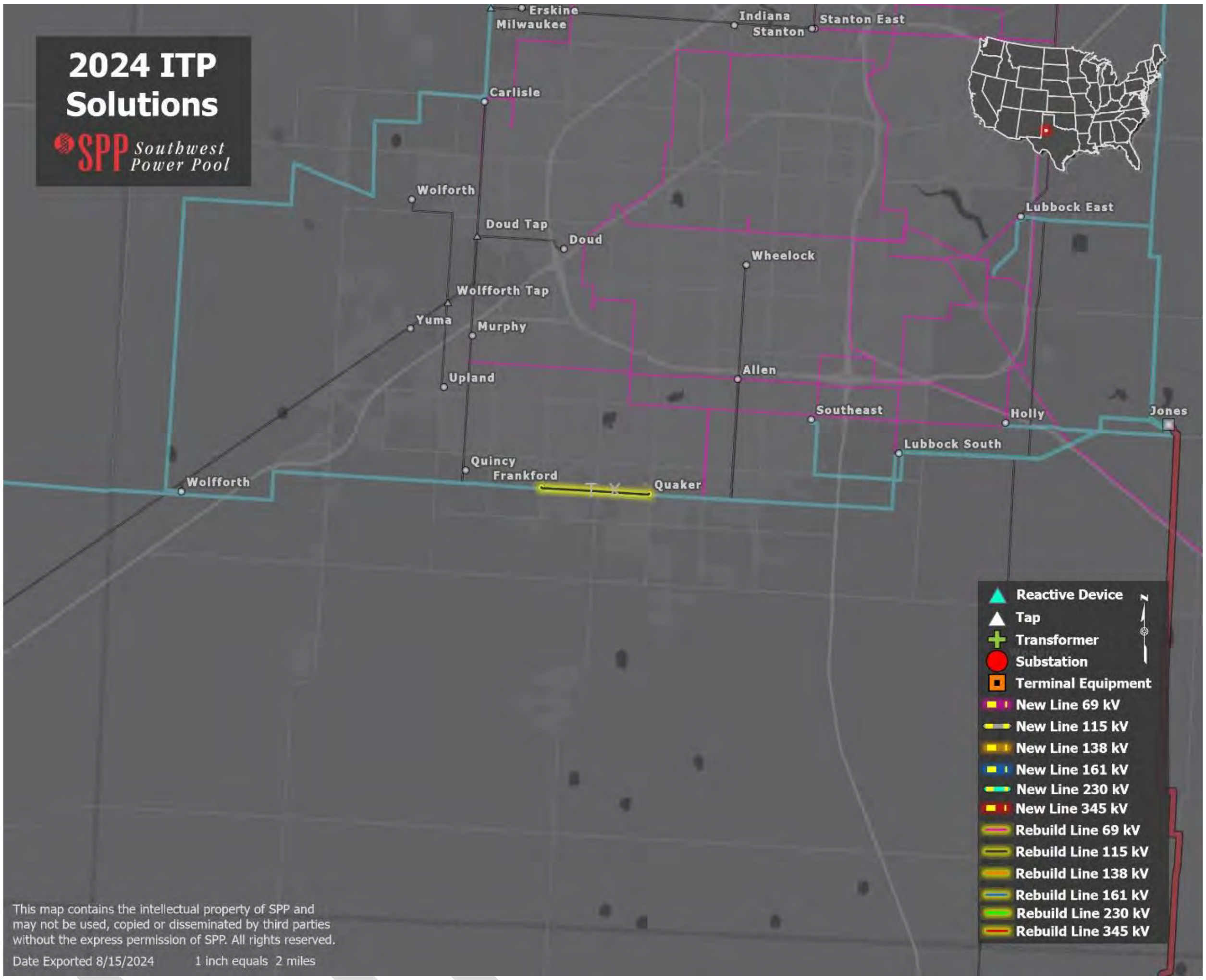

Figure 6.36: SPS: Frankford - Quaker 115 kV Rebuild

South of Lubbock, Texas, the Frankford to Quaker 115 kV line overloads with the loss of the 230 kV line between Wolfforth and Lubbock South. Rebuilding Frankford to Quaker would relieve the thermal violation and strengthens the 115 kV system to ensuring effective power delivery in all seasons.

6.1.12.10 *LUBBOCK EAST – LUBBOCK SOUTH 115 KV TERMINAL EQUIPMENT (RELIABILITY)*

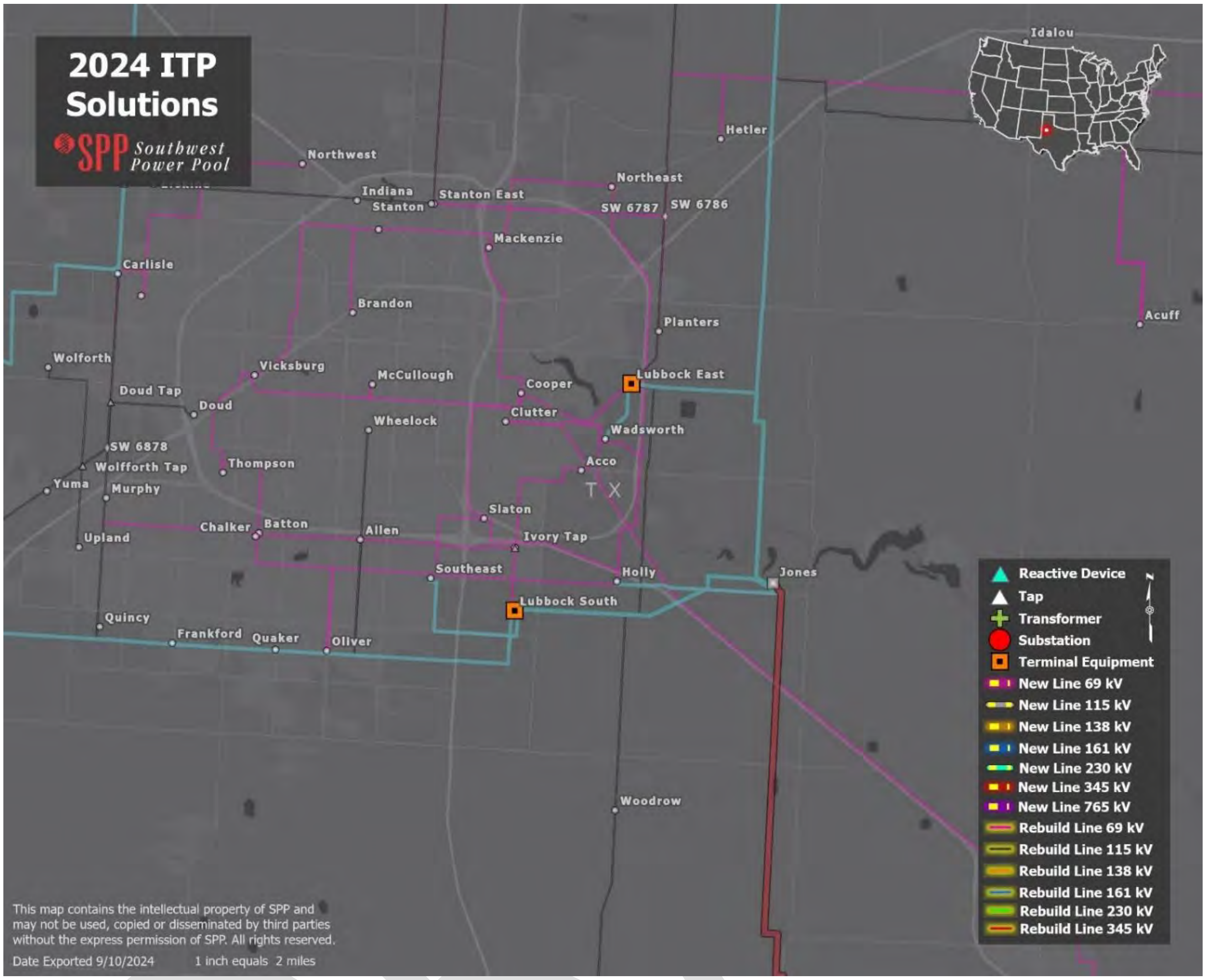

Figure 6.37: SPS: Lubbock East - Lubbock South 115 kV Terminal Equipment

In northwestern Texas, the Lubbock East to Lubbock South 115 kV line is overloaded for the loss of any one of various nearby 115 kV lines. The most severe overload, caused by the loss of the Quaker to Lubbock South 115 kV line, in the year two summer scenario, raised the line loading to 114%. Throughout portfolio development, the Lubbock East to Lubbock South 115 kV terminal equipment upgrade project was considered for inclusion in the final portfolio. However, SPP staff found that it was unnecessary due to the violation not persisting in year five and year 10.

During the final reliability assessment, after incorporating the consolidated portfolio into the base reliability models, the Lubbock East to Lubbock South 115 kV line was overloaded in the base case of the year two summer and year 10 winter scenarios. This line also overloaded in the year two winter, year five summer and winter, and year 10 summer for the loss of nearby elements on the 115 kV and 230 kV systems. The Lubbock East to Lubbock South 115 kV terminal equipment upgrade would effectively resolve these overloads. With thermal violations now in base case, as well as persisting through to year five and 10 scenarios under contingency conditions, SPP chose the terminal equipment upgrade to be included in the final portfolio.

6.1.13 UPPER MISSOURI ZONE (UMZ)

6.1.13.1 *NORTHWEST NORTH DAKOTA PROJECTS (RELIABILITY/ECONOMIC)*

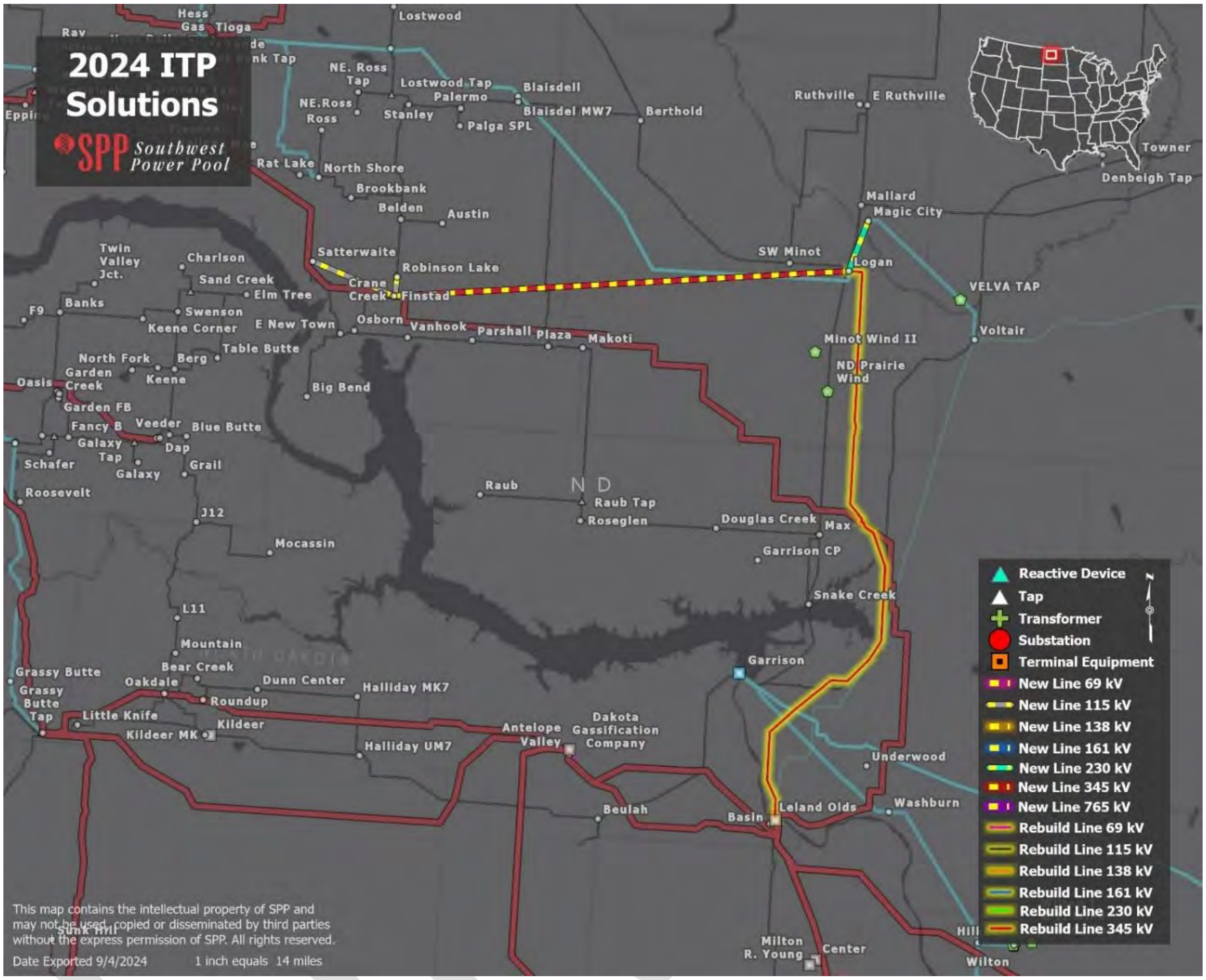

Figure 6.38: UMZ: Northwest North Dakota Projects

The northwest North Dakota region was analyzed in a comprehensive manner due to common drivers behind the area's needs. Considerable load growth caused several overloads and low voltages in the area. The analysis led SPP to recommend a holistic solution that addressed all of the area's needs. The recommended solution included converting the existing Logan to Leland Olds 230 kV line to 345 kV and establishing a new 230 kV line from Logan to Magic City. To maximize the cost-effectiveness of the project, the new 230 kV line from Logan to Magic City reconfigures the existing Logan to Mallard 115 kV line to 230 kV. To further enhance reliability, a new 345 kV line from Logan to Finstad was selected as a redundant source to the Finstad area. New 115 kV lines from Robinson Lake to Finstad to Satterwaite ensure a robust underlying system to reliably serve load.

These groups of projects were able to completely resolve voltage collapse as well as thermal overloads, some of which were more than 120% of the monitored element's emergency rating. In addition to the reliability benefits provided by the project, the combination of projects was able to provide a considerable reduction in congestion for several nearby constraints.

6.1.13.2 *KINGSBURY COUNTY PROJECT (RELIABILITY)*

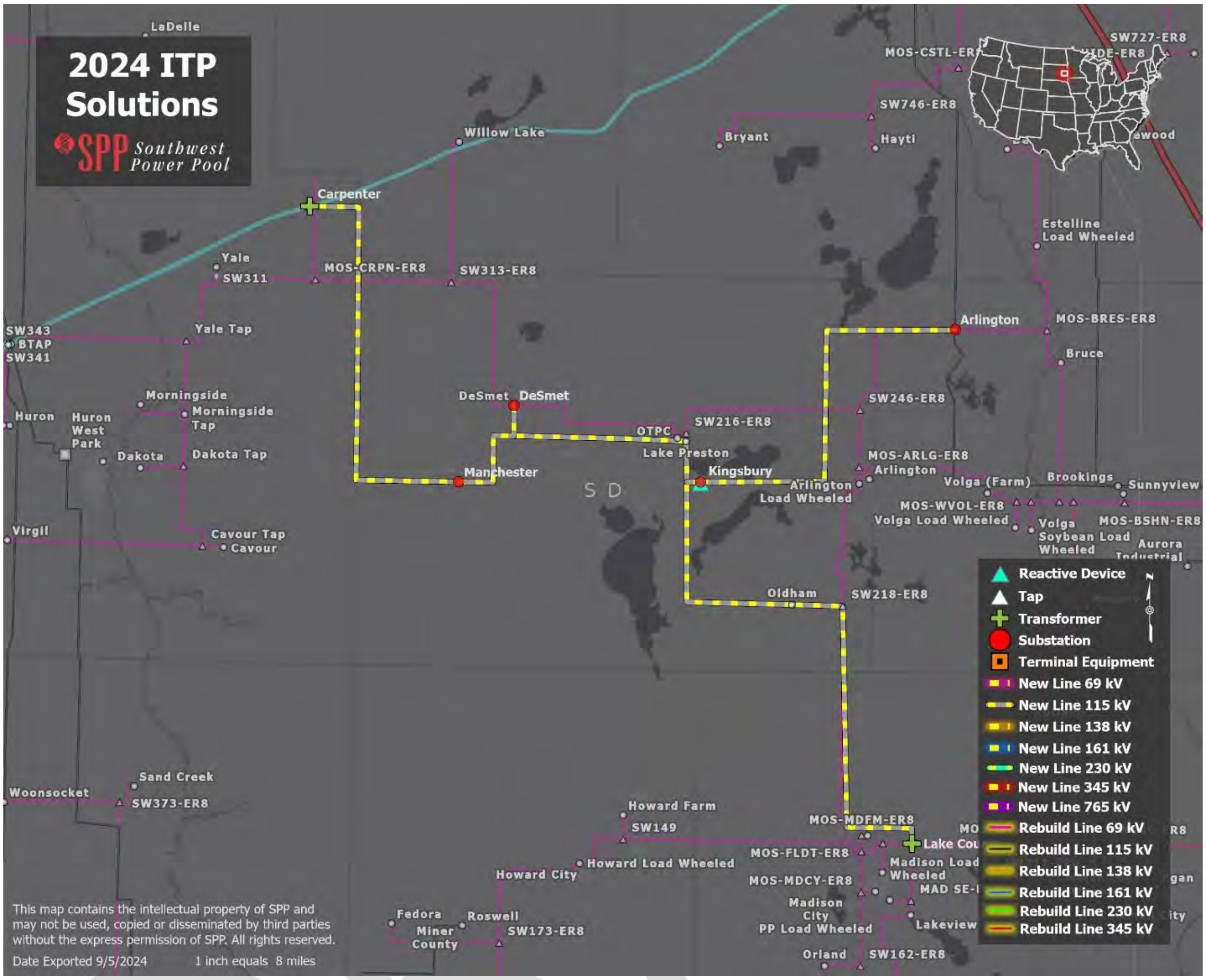

Figure 6.39: UMZ: Kingsbury County Project

Located in southeast South Dakota near the Kingsbury County line, an extensive set of 115 kV projects were selected (shown in Table 6.2) to mitigate numerous needs because of load additions. The selected projects mitigate more than 160 needs that consisted of nine overloaded transmission lines as well as voltage violations at 48 buses spanning all model years and seasons. One of the worst thermal overloads mitigated was the base case thermal overload of approximately 254% of the Arlington 115/69 kV transformer's rating. Additionally, the project was able to completely resolve the voltage collapse seen on 69 kV system by converting to a more robust 115 kV system. This group of projects was selected because of the extreme relief provided by the projects while also utilizing the existing infrastructure where possible to maximize cost effectiveness.

Upgrade Type	Upgrade	Approximate Mileage
New Line	Carpenter - Manchester 115 kV	21.8
	Manchester – DeSmet 115 kV	7.9
	DeSmet – Lake Preston 115 kV	12.2
	Lake Preston – Kingsbury 115 kV	4.0

Upgrade Type	Upgrade	Approximate Mileage
	Kingsbury – Oldham 115 kV	8.6
	Kingsbury – Arlington 115 kV	18.4
Voltage Conversion (69 kV to 115 kV)	Oldham – Lake County 115 kV	17

Table 6.2: Kingsbury County Project

6.1.13.3 TOBIAS – ELM CREEK AND SIDNEY – HOLCOMB 345 KV NEW LINES (PERSISTENT OPERATIONAL/WINTER WEATHER)

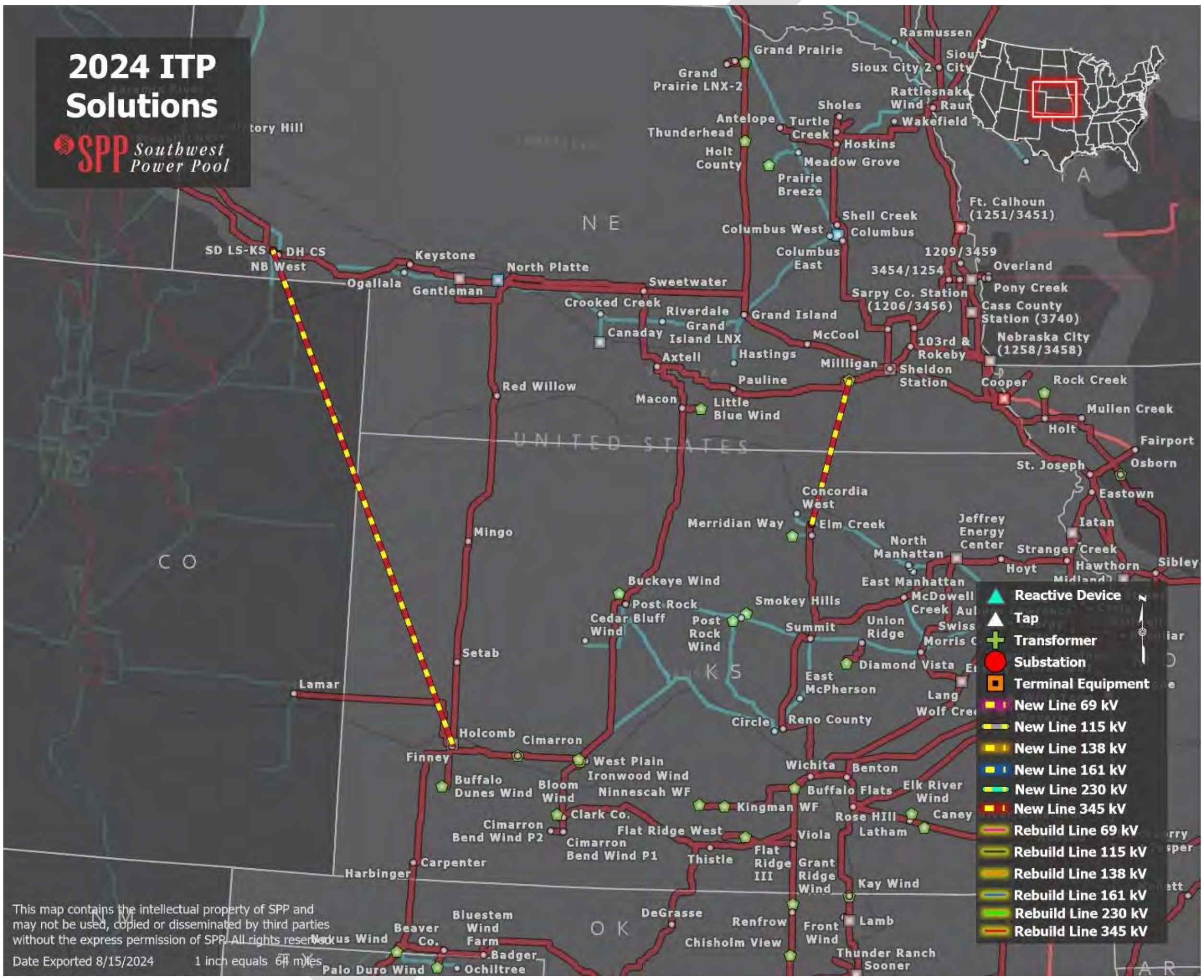

Figure 6.40: UMZ: Tobias – Elm Creek and Sidney – Holcomb 345 kV New Lines

Stretching from western Nebraska to northwestern Kansas, the new 85.2-mile 345 kV line from Tobias to Elm Creek was selected to address winter weather needs observed in the Uri-based winter weather models. There are a variety of benefits that come with the construction of this new line, including increased transfer capability and voltage support. The primary driver for this project is increasing the north to south transfer capability of the SPP footprint. By itself this project increases that capability by 900 megawatts. It also solves 92% of the year 10 winter weather voltage violations in the target area.

SPP also selected the Sidney to Holcomb 345 kV new line to address winter weather needs based on the Uri-based winter weather models. The primary driver for this project is increasing the north to south transfer capability of the SPP footprint. By itself this project increases that capability by 650 megawatts. It also solves 78% of the year 10 winter weather voltage violations in the target area.

The combined benefit of the new 345 kV line from Sidney to Holcomb and the new 345 kV line from Tobias to Elm Creek is increased from each of these projects individually. The total transfer capability increase from the north of SPP to the south is 1500 megawatts. The combination also solves 98% of the year 10 winter weather voltage violations and reduces the load shed by 433 MW in the target area as shown in Table 6.3.

Project Description	Transfer Capability Increase (MW)	% Voltage Violations Mitigated in the Transfer Area	Load Shed Decrease due to Project (MW)
Sidney to Holcomb	650 MW	78%	177
Tobias to Elm Creek	900 MW	92%	300
Tobias to Elm Creek and Sidney to Holcomb	1500 MW	98%	433

Table 6.3: Winter Weather Project Benefits (Year 10 model)

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6.1.13.4 15TH AVE – WATERTOWN 115 KV REBUILD (RELIABILITY)

Figure 6.41: UMZ: 15th Ave – Watertown 115 kV Rebuild

In northeast South Dakota, the 115 kV line from Watertown to 15th Avenue becomes overloaded for the loss of the 115 kV Watertown to Pelican line. Rebuilding the Watertown to 15th Avenue 115 kV line not only would eliminate the overload but also enhance the overall reliability in the area.

6.1.13.5 *BELFIELD – MAURINE – NEW UNDERWOOD – LARAMIE RIVER 345 KV NEW LINE (ECONOMIC)*

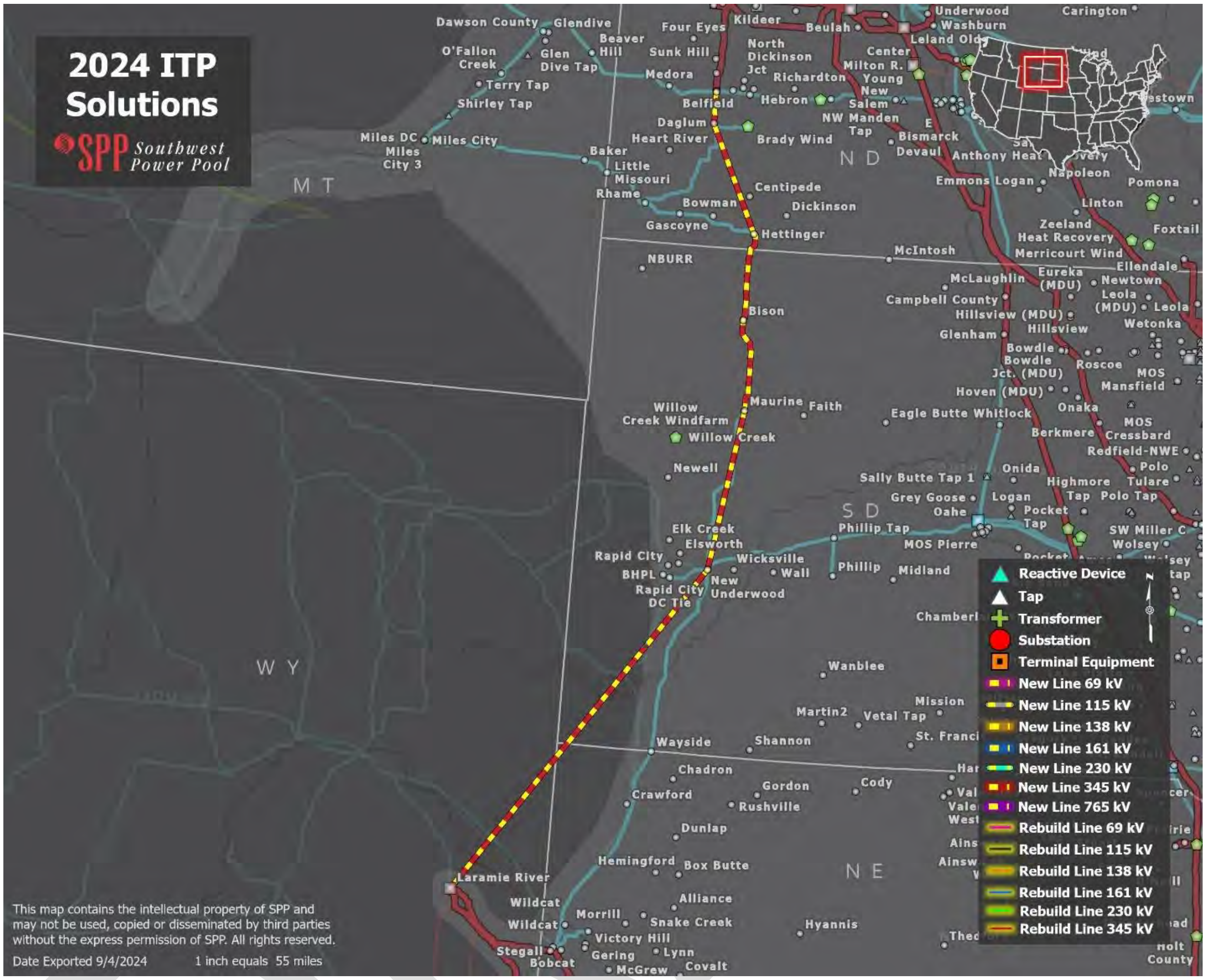

Figure 6.42: UMZ: Belfield – Maurine – New Underwood – Laramie River 345 kV New Line

The new line from Belfield to Maurine to New Underwood to Laramie River is a 438.6-mile 345 kV project that brings large economic benefits. In Future 2 year 10 the project would resolve 100% of the congestion that occurs on the Centipede to Hettinger 115 kV line when the Bowman to Hettinger 230 kV line is lost. It also would provide 96% congestion relief at Belfield for the loss of one of the 345/230 kV transformers. Further, it would provide a good source from the EHV system in Nebraska to parts of North Dakota that are experiencing load growth as well as removing the need for 230 kV upgrades that would otherwise be needed in the Belfield area. While increasing south-to-north transfers, the project also would bypass the congested Snake Creek – Alliance corridor, providing congestion relief to that constraint and its adjacent segments. As mentioned in the Executive Summary, the Department of Energy also put out a National Transmission Needs Study[42] that highlights the need for EHV transmission in this area. This project would fulfill the EHV deficiency in this area creating more energy equity for the rural communities in western Nebraska, South Dakota, and North Dakota.

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[42] https://www.energy.gov/gdo/national-interest-electric-transmission-corridor-designation-process

6.1.13.6 *BISMARCK – EAST BISMARCK 115 KV REBUILD (RELIABILITY/ECONOMIC)*

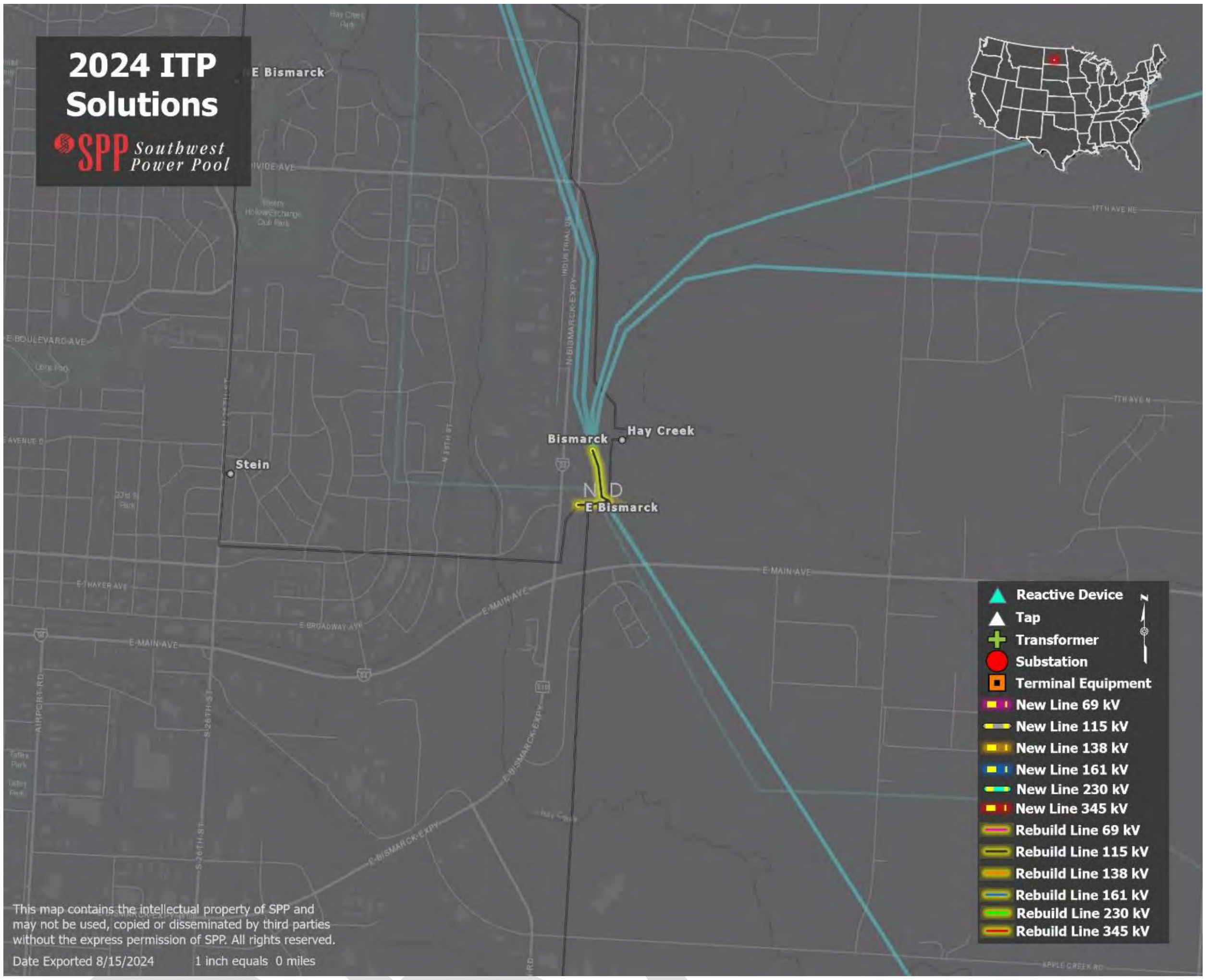

Figure 6.43: UMZ: Bismarck - East Bismarck 115 kV Rebuild

In south central North Dakota, the Bismarck to East Bismarck 115 kV line is a low-rated facility in need of a rebuild. This line shows economic congestion in both year five and year 10, and thermally overloaded in year 10 of the reliability cases. Rebuilding this line would offer complete relief from overloads in the event of the loss of the Ward to Bismarck 115 kV line and bring greater reliability to the Bismarck area in North Dakota.

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6.1.13.7 *WISDOM 161/69 KV TRANSFORMER AND SPENCER – WISDOM 69 KV REBUILD (RELIABILITY)*

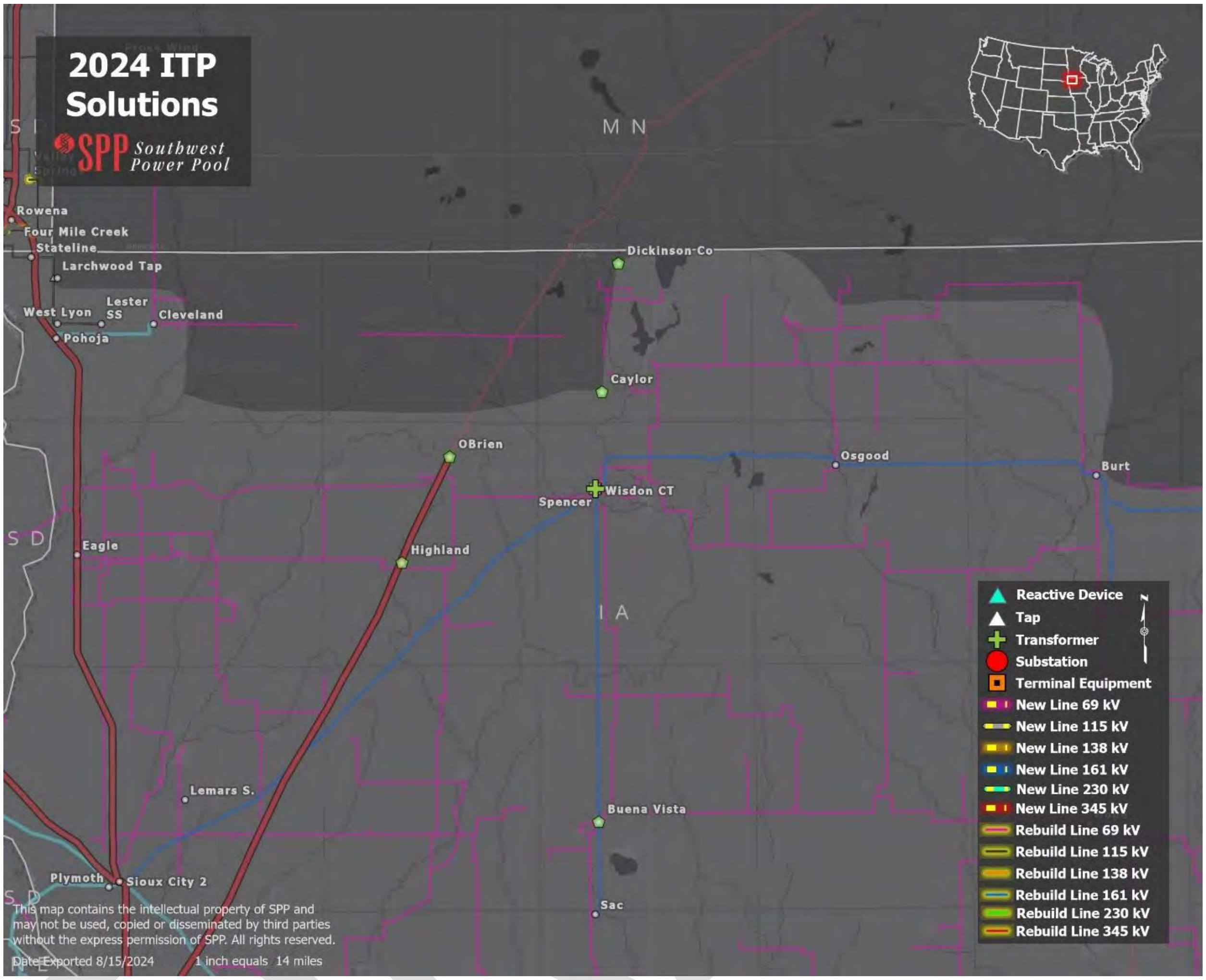

Figure 6.44: UMZ: Wisdom 161/69 kV Transformer

In northwest Iowa, the Spencer to Wisdom 69 kV line overloads when the nearby Wisdom to Sanborne 69 kV line is lost. SPP staff considered various projects to resolve this need including a second circuit from Spencer to Wisdom 69 kV, a rebuild of Spencer to Wisdom 69 kV, and a new 161/69 kV transformer at Wisdom. While all three of these options would resolve the violation, the original project chosen for the portfolio was the new transformer at Wisdom because of the crowding at the Spencer and Wisdom substations.

Through the final reliability assessment SPP staff discovered a loop that would be created between the 161 and 69 kV system on the Spencer and Wisdom substations if this transformer were to be installed. This loop would make the loss of the Spencer to Wisdom 161 kV line more impactful, causing the same overload. When considering the effects of each project, the rebuild of the Spencer to Wisdom 69 kV line (as shown in Figure 7.1) was selected as it would sufficiently resolve the violation observed in the year five and year 10 winter scenarios without causing additional violations.

6.1.13.8 *PROJECTS ADDRESSING INCREASING LOAD IN NORTHWEST NORTH DAKOTA (RELIABILITY/ECONOMIC)*

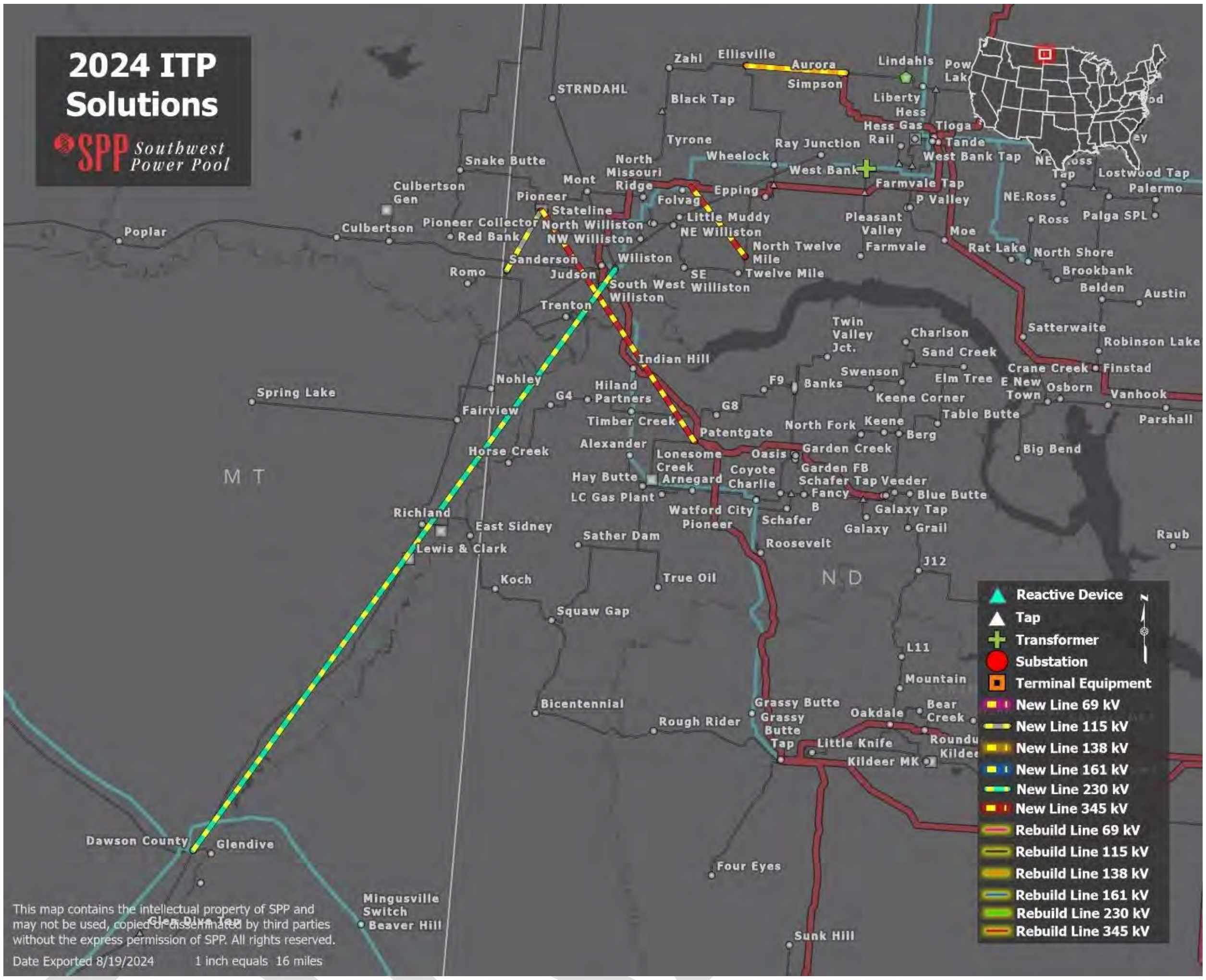

Figure 6.45: UMZ: Projects Addressing Increasing Load in Northwest North Dakota

This group of projects would resolve voltage, thermal and economic issues in the northwest part of North Dakota. The needs are mostly driven by increasing load in this area. The projects described below are a holistic solution for the needs in the area.

Upgrade Type	Upgrade	Approximate Mileage
New Line	Dawson County to Williston 230 kV	103.7
	Pioneer to Sanderson 115 kV	10.1
	Simpson to Ellisville 115 kV	15.6
	Patent Gate to Pioneer 345 kV	33.5
	Spring Brook to Twelve Mile 345 kV	9
New Transformer	West Bank 345/115 kV Transformer	N/A

Table 6.4: Projects Addressing Increasing Load in Northwest North Dakota

The new 230 kV line from Dawson County, Montana to Williston, North Dakota would provide reliability and economic benefits. Additionally, this line would resolve both year two and year 10 thermal overloads on the 115 kV system between Dawson County and Lewis and Clark for the loss of the Belfield to Charlie Creek 345 kV line. Congestion would be greatly reduced on the 115 kV system between Dawson County and Williston with the addition of this project.

The new 115 kV line from Pioneer to Sanderson would solve reliability needs for the Williston to Ren 115 kV line when Sanderson to Romo 115 kV is lost. This line would resolve several other contingent line losses. The needs addressed by this project include year five and year 10 base reliability needs. During the final reliability assessment, the same overload on Williston to Ren was observed under N-1 conditions for the loss of the new Sanderson to Pioneer 115 kV branch. Before the new branch from Sanderson to Pioneer is in place, the Williston to Ren line is on a radial path, therefore a rebuild on this line is not feasible. With the Sanderson to Pioneer project being included in the portfolio, looping the line into the system, it would be possible and advantageous to rebuild the Williston to Ren 115 kV line (as shown in Figure 7.1). The rebuild along with the new line would address the reliability violation so that the overload will not occur under base case or N-1 conditions.

Located northeast of Williston, North Dakota, the new 115 kV line from Simpson to Ellisville would address multiple voltage needs in the area. The voltage support from the new line when coupled with a 15 MVAR capacitor bank at Zahl would be enough to correct the area’s voltage support needs and increase the area’s reliability.

The Patent Gate to Pioneer 345 kV line was selected to provide congestion relief for the economic constraint on the 230 kV line from Watford to Charlie Creek for the loss of the Judson to Patent Gate 345 kV line. The new line would provide an increase in transfer capacity for the large loads located in the northwest region of North Dakota and provides a parallel path to the contingency to alleviate the severe congestion in this area. In addition to providing economic benefit, the new line would correct voltage collapse seen in the area, as well as a thermal overload seen on the Watford to Charlie Creek 230 kV line during the year 10 winter base reliability model.

The West Bank transformer project would tap the Spring Brook to Tande 345 kV line and tie into the nearby West Bank South 115 kV substation. The new transformer addition would mitigate several voltage issues seen in the year 10 Summer Base Reliability models by allowing higher reactive power transfer to the 115 kV system in this area during periods of high load.

The Spring Brook to Twelve Mile 345 kV new line would be in the northwest region of North Dakota and was chosen primarily for its ability to provide significant voltage support to the high loads seen in this area as well as solving several thermal needs seen in the year 10 base reliability models.

6.1.13.9 *CHADRON VALLEY 115 KV REBUILDS (ECONOMIC)*

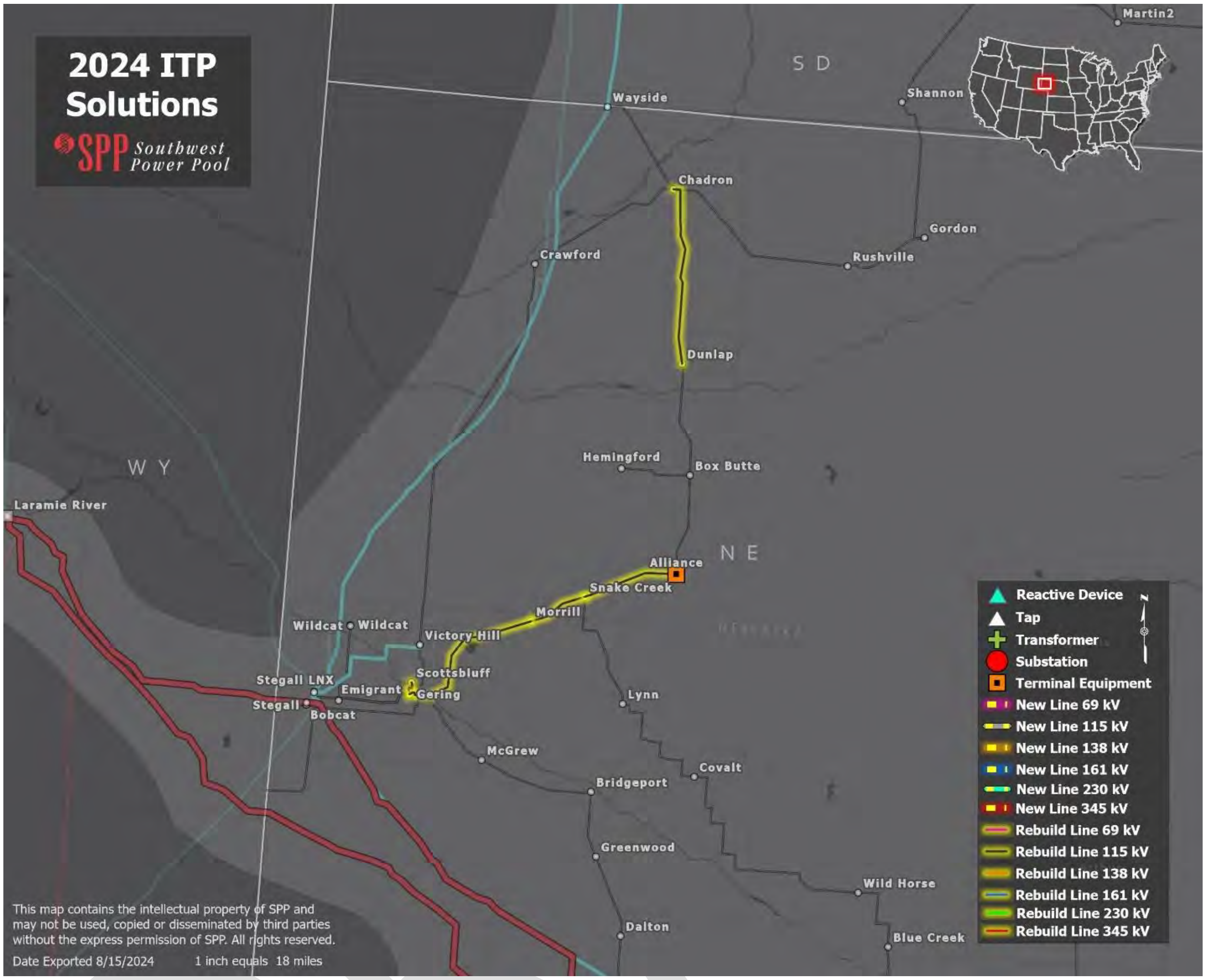

Figure 6.46: UMZ: Northwest Nebraska Projects

The Alliance to Snake Creek 115 kV terminal upgrade is recommended as a short-term solution to address operational needs. While the short-term solution would provide relatively immediate production cost relief, planning models indicate the congestion would become more severe through the long term. The long-term solution for this congestion is a rebuild of Alliance to Snake Creek to Morrill to Gering Tap to Scotts Bluff as well as Chadron to Dunlap 115 kV lines. The recommendation by SPP staff to rebuild these lines is based on heavy congestion that occurs for the loss of the Wayside to Stegall 230 kV line as well as several other 345 kV line losses nearby. Combining these rebuilds would significantly reduce congestion in the area. These rebuilds also would work together with the Laramie to New Underwood to Maurine to Belfield 345 kV New Line project to increase south-to-north flows along the northwestern edge of the SPP footprint.

6.1.13.10 *115 KV SYSTEM RECONFIGURATION AT HANSON COUNTY SOUTH DAKOTA AND MOUNT VERNON 115 KV CAPACITOR (RELIABILITY)*

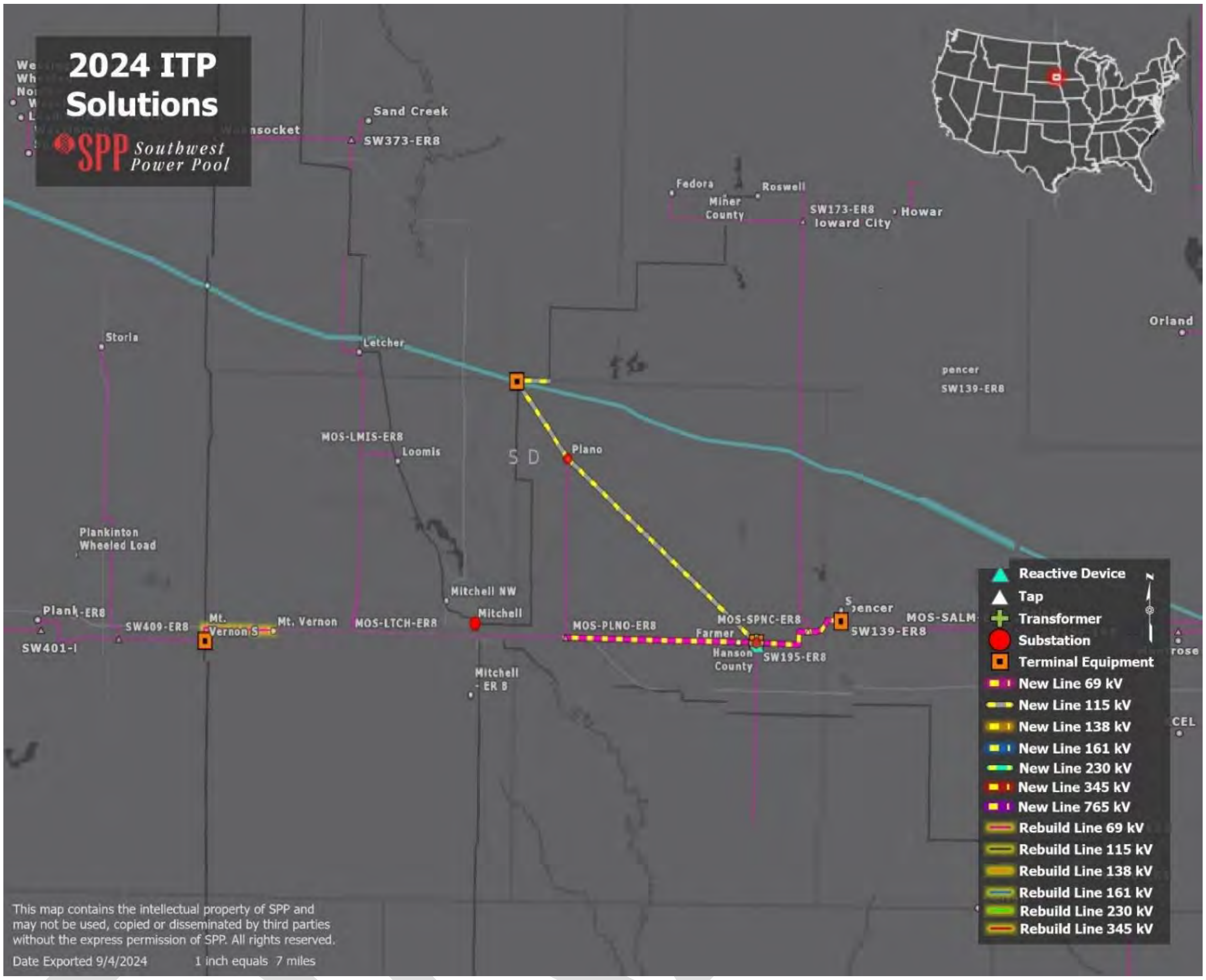

Figure 6.47: UMZ: System Reconfiguration at Hanson County South Dakota 115 kV

This project would reconfigure the 115 kV system in the transmission system in the Hanson County area of South Dakota and build a new 115 kV line from Letcher to Plano to a new Hanson County substation. New 69 kV lines would be built from Spencer to Hanson County to Mitchel as well as new lines from Mt. Vernon to Mitchel and Mt. Vernon to Letcher Tap. The project would address Zonal Planning Criteria MW-mile violations. The complete project would address regional reliability thermal needs at Mount Vernon and VT Hanlon and many 69 kV voltage needs in the area.

Topology enhancements from the Hanson County 115 kV system reconfiguration now keep three substations on the 69 kV system, Mount Vernon, Plankinton, and SW Storla, in service when the Mount Vernon transformer is lost, where previously the buses were islanded due to the contingency. The final reliability assessment discovered that each substation shows low per unit voltage under this contingency. The project SPP staff chose to resolve these low voltage violations is to place a 7.5 MVAR capacitor bank at the Mount Vernon 69 kV substation (shown in Figure 7.1). This capacitor bank allows effective regulation of the per unit voltage at the substations to be within the normal operating limits.

6.1.13.11 *SYSTEM RECONFIGURATION AT MADISON SOUTH DAKOTA 115 KV (RELIABILITY)*

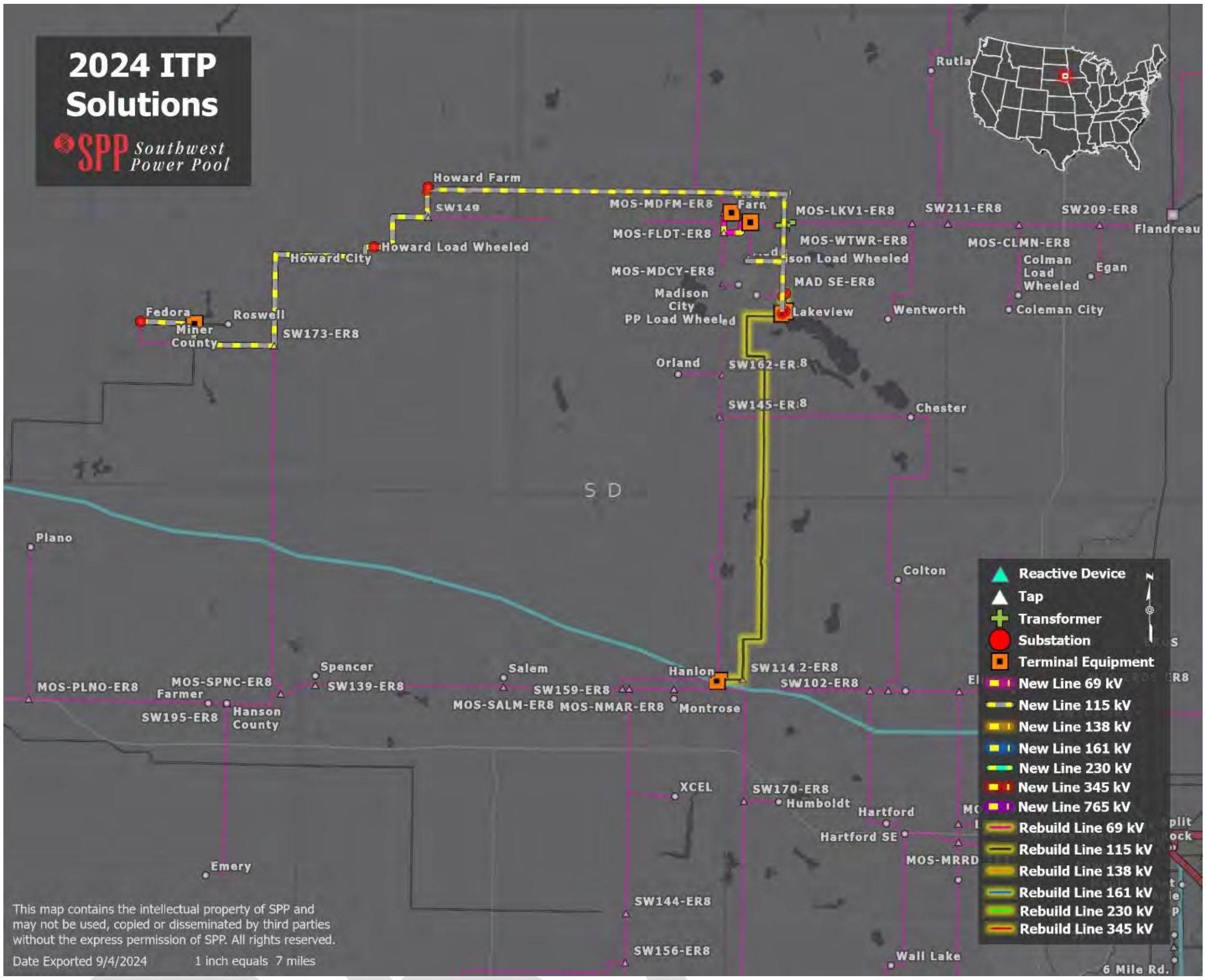

Figure 6.48: UMZ: System Reconfiguration at Madison South Dakota 115 kV

This project would reconfigure the 115 kV system near Madison, South Dakota and builds a new 115 kV line from Fedora to Roswell to Howard to Lake County to Lakeview. The Hanlon to Lakeview line is also converted from 69 kV to 115 kV. The project would address Zonal Planning Criteria MW-mile violations. The complete project addresses regional reliability, thermal, and voltage needs in the Lake Preston and Howard areas.

6.1.13.12 VOLTAGE CONVERSION AT MARION SOUTH DAKOTA 115 KV AND HUTCHINSON 115 KV CAPACITOR (RELIABILITY)

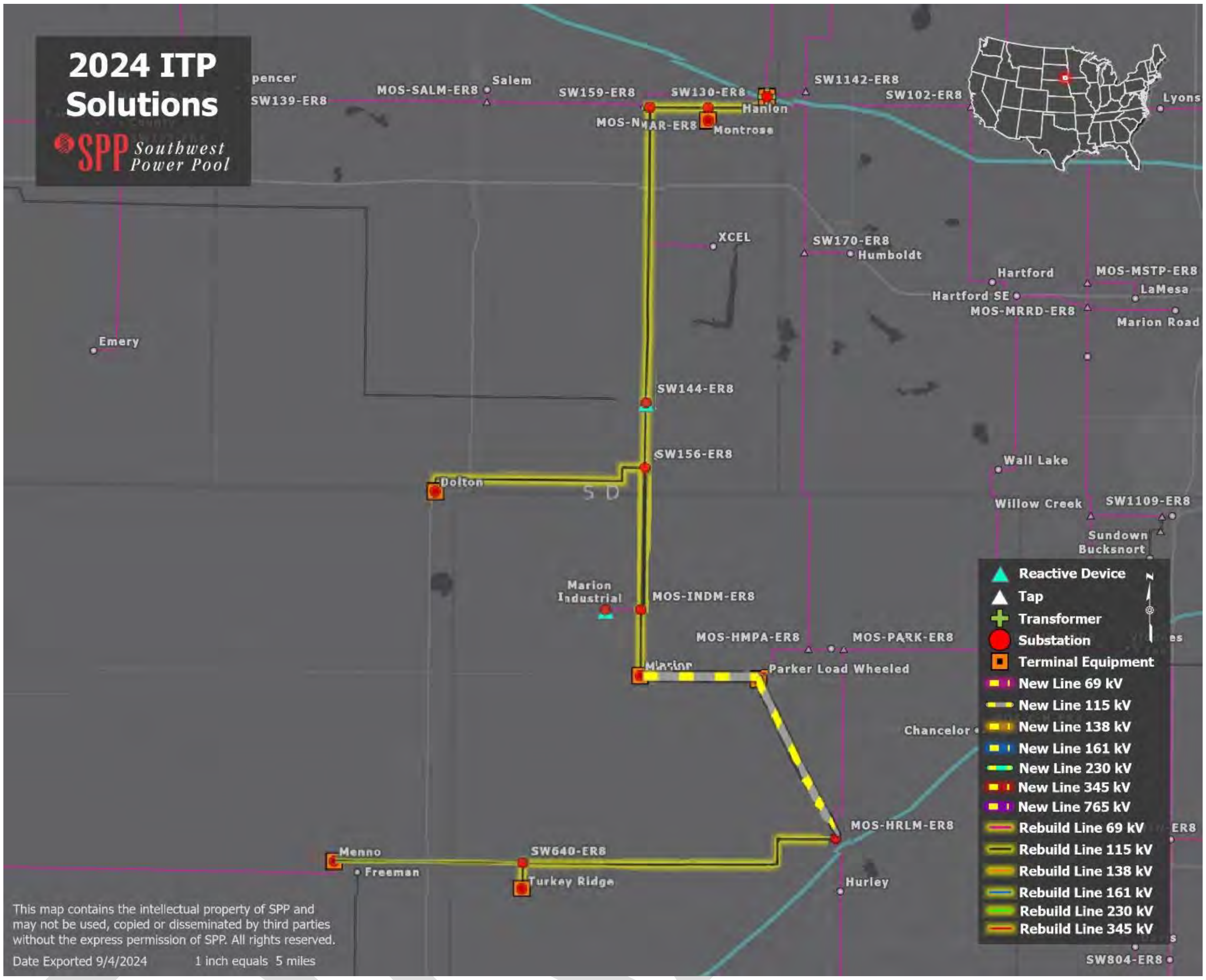

Figure 6.49: UMZ: Voltage Conversion and Reconfiguration at Marion South Dakota 115 kV

This project would convert the 69 kV system into 115 kV in the Marion area in southeast South Dakota. A new 115 kV line would be built from Marion to Parker to a new Turner County substation near Hurley. Additionally, the Hanlon to Marion 69 kV line would be converted to 115 kV operation while the Menno Tap to Turner County and Dolton to Dolton Tap lines would be re-insulated to 115 kV. This conversion and accompanying upgrades would address Zonal Planning Criteria MW-mile violations as well as thermal needs at Hanlon and a large number of voltage needs within the Canistota and Dolton 69 kV and 115 kV systems.

Following the introduction of the Marion area conversion, low voltage violations identified in the final reliability assessment occur at the Hutchinson County, Freeman, and SW640 (Turkey Ridge) 115 kV substations when the 115 kV line from Utica Junction to Hutchinson County is lost. The Hutchinson County substation is the new substation tapping the existing Utica Junction to Freeman 115 kV line. The Freeman substation was previously islanded in the event of a Utica Junction to Freeman line outage. The SW640 (Turkey Ridge) substation would be converted from 69 kV to 115 kV. For these reasons, low voltage occurs on all three substations. A 20 MVAR capacitor bank placed at the

Hutchinson 115 kV substation (shown in Figure 7.1) was chosen to address these violations and is sufficient to bring the bus voltages up to the planning criteria voltage operating range.

6.1.13.13 *SIOUX FALLS SOUTH DAKOTA AREA 115 KV SYSTEM RECONFIGURATION AND HARRISBURG – LINCOLN 115 KV REBUILD (RELIABILITY)*

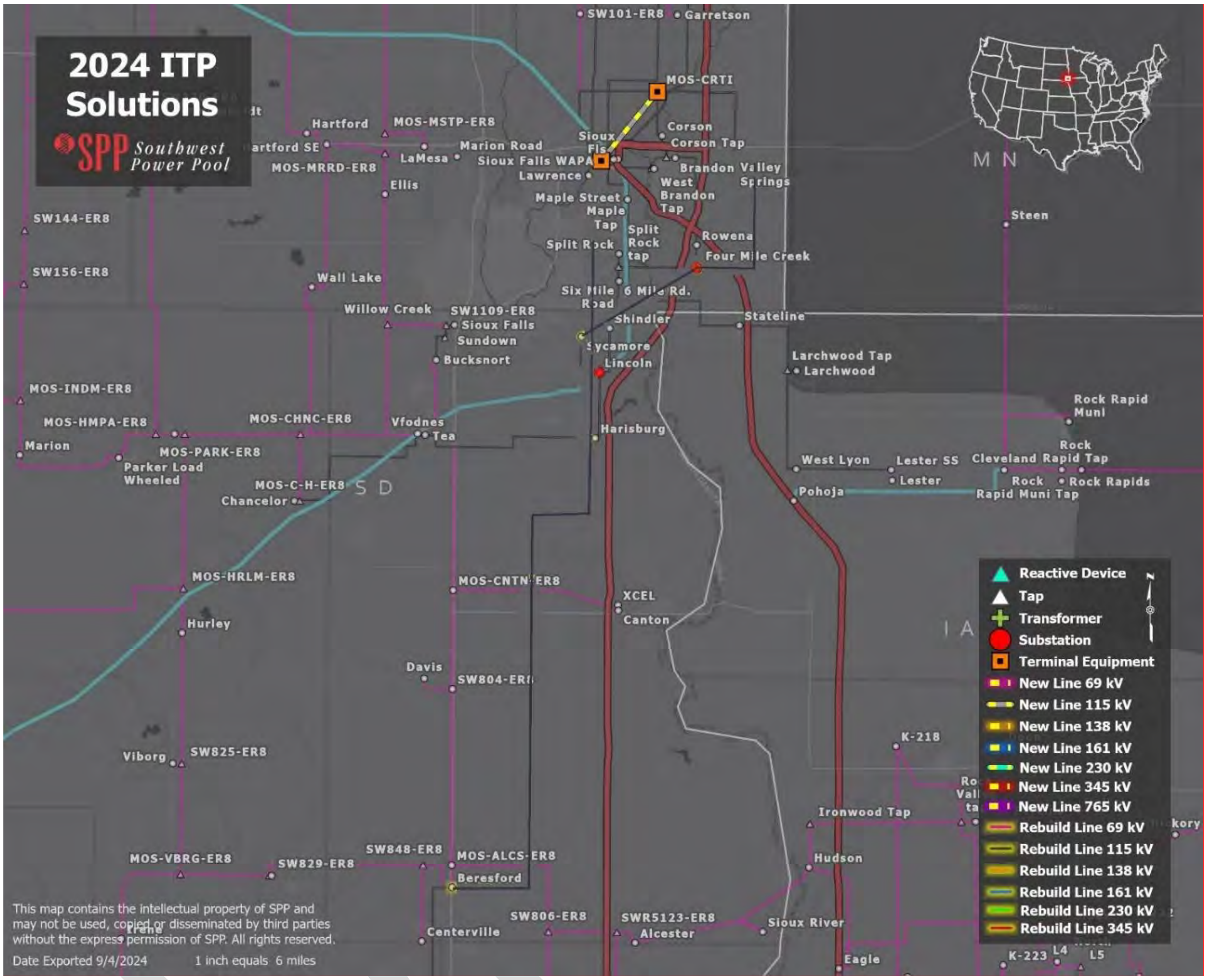

Figure 6.50: UMZ: Sioux Falls South Dakota Area 115 kV System Reconfiguration

In southeastern South Dakota, violations of Zone 19's MW-mile Zonal Planning Criteria exist. To address these violations, SPP recommends a project to reconfigure the 115 kV system in the Sioux Falls area and includes the construction of two 115-kV switching stations and line terminal work. The new 115 kV line from Sioux Falls to Palisade shown is already complete but is included for reference since it is part of the overall project. The complete project would address regional reliability thermal needs for the Virgil Fodness transformer as well as a large number of voltage needs in the area.

After this reconfiguration near Sioux Falls, the new Lincoln County to Sioux Falls 115 kV line overloads in year 10 summer when the Virgil Fodness transformer is lost. Also, under the same contingency, the Harrisburg to Lincoln County 115 kV line is no longer islanded, and overloads in year five and 10 summer. These violations were identified in the final reliability assessment. The Lincoln County to Sioux Falls 115 kV terminal upgrade, and Harrisburg to Lincoln County 115 kV line rebuild (shown in Figure 7.1) are the selected projects to resolve the respective needs. Upgrading the terminal equipment would allow the line rating to reach 193 MVA which adequately relieves the loading on the new Lincoln County to Sioux Falls 115 kV line. Rebuilding the Harrisburg to Lincoln County 115 kV line to the standard MVA rating for a 115 kV line would result in the line no longer being overloaded during the contingency condition.

6.1.14 WESTERN FARMERS ELECTRIC COOPERATIVE (WFEC)

6.1.14.1 *COLBERT 138 KV CAPACITOR (RELIABILITY)*

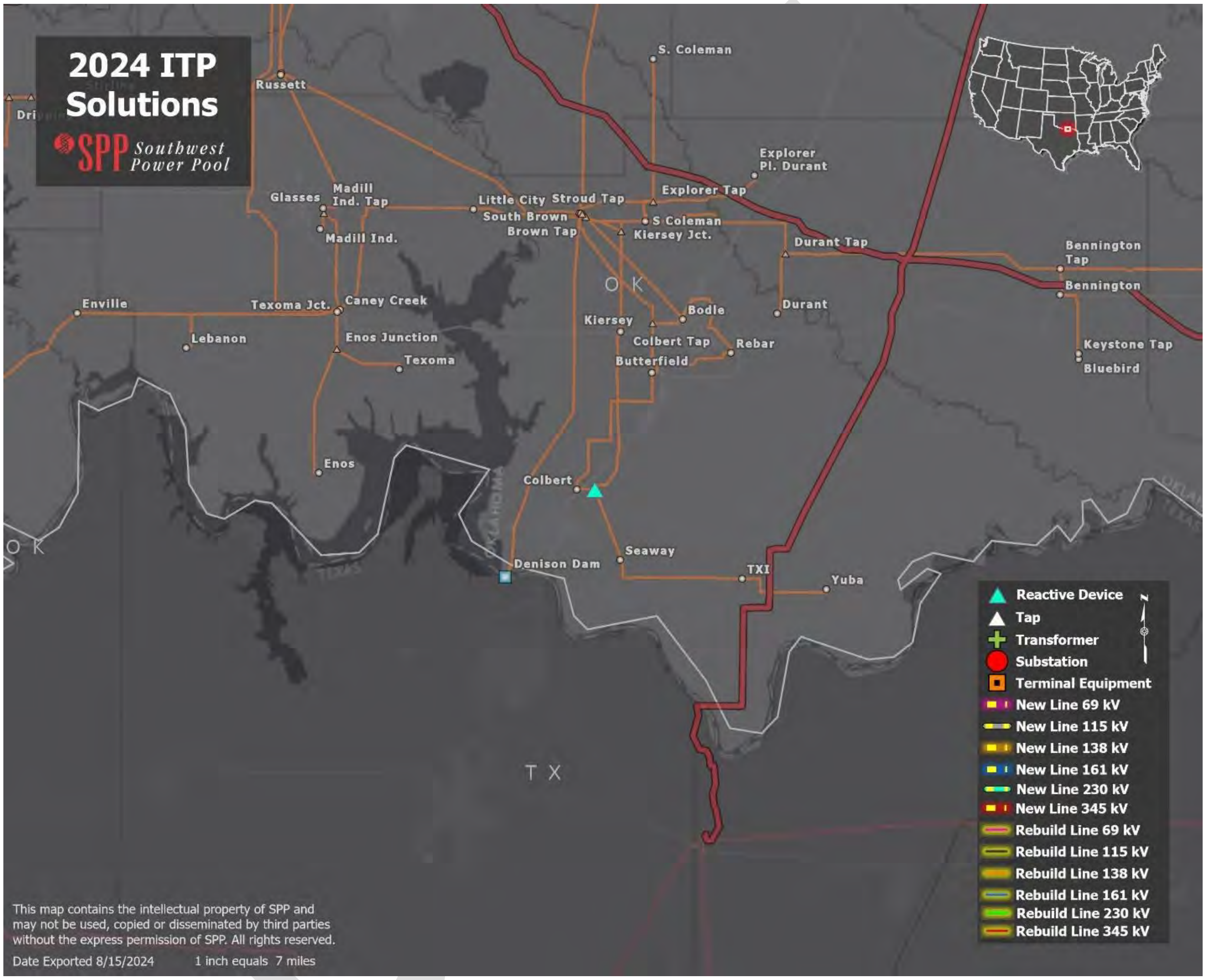

Figure 6.51: WFEC: Colbert Oklahoma Area 138 kV Capacitor

SPP staff recommends the installation of a six MVAR capacitor at the Colbert substation in southcentral Oklahoma. This new capacitor would mitigate the voltage needs that appear in the year 10 summer and winter models during the base case and various contingencies in the southern Oklahoma area.

6.2 ADDITIONAL PROJECTS

6.2.1 SHORT-CIRCUIT PROJECTS

2024 ITP short-circuit projects consist of three over-dutied fault interrupting equipment upgrades. These upgrades would ensure SPP's members can meet short-circuit analysis requirements in the NERC TPL-001-5 standard.

Short-Circuit Project	Area	Scenario
S1260 161 kV Breaker Replacement	OPPD	25S / BR
Tinker 138 kV Two Breaker Replacements	OGE	25S / BR

Table 6.5: Short-Circuit Projects

6.2.2 POLICY PROJECTS

No public policy needs were identified in the 2024 ITP; therefore, no policy projects were identified in the 2024 ITP.

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7 INFORMATIONAL PORTFOLIO ANALYSIS

7.1 BENEFITS

7.1.1 METHODOLOGY

SPP used benefit metrics to measure the value and economic impacts of the consolidated portfolio. The Benefit Metrics Manual[43] provides the definitions, concepts, calculations, and allocation methodologies for all approved metrics. The ESWG directed SPP staff to calculate the 2024 ITP benefit-to-cost ratios for the final portfolio using the Future 1 and Future 2 models. The benefit analysis is performed on all reliability and economic projects in the consolidated portfolio. The benefit metrics listed below are calculated as the incremental benefit of the projects included in the portfolio.

Benefit Metrics:

- Adjusted Production Cost (APC) Savings
- Savings Due to Lower Ancillary Service Needs and Production Costs
- Avoided or Delayed Reliability Projects
- Marginal Energy Losses
- Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
- Reduction of Emissions Rates and Values
- Public Policy Benefits
- Assumed Benefit of Mandated Reliability Projects
- Mitigation of Transmission Outage Costs
- Increased Wheeling Through and Out Revenues

7.1.2 APC SAVINGS

APC captures the monetary cost associated with fuel prices, run times, grid congestion, unit operating costs, energy purchases, energy sales and other factors that directly relate to energy production by generating resources in the SPP footprint. Additional transmission projects aim to relieve system congestion and reduce costs through a combination of a more economical generation dispatch, more economical purchases and optimal revenue from sales.

To calculate benefits over the expected 40-year life of the projects,[44] SPP staff analyzed two years, 2028 and 2033. SPP staff calculated APC savings accordingly for these years, and then extrapolated the benefits for the initial five-year period based on the slope between the two points. After that, the benefits are assumed to grow at an inflation rate of 2.0% per year. SPP staff then discounted each

[43] Benefit Metrics Manual

[44] The SPP OATT requires that the portfolio be evaluated using a 40-year financial analysis.

year's benefit to 2028 dollars using an 8% discount rate, and a 2.0% inflation rate from 2028 dollars back to 2024 dollars. The sum of all discounted benefits was presented as the PV benefit. SPP staff performed this calculation for every zone.

Table 7.1 provides the zonal breakdown and the PV estimates of APC savings. Future 2 has higher congestion compared to Future 1. Therefore, the projects in the recommended portfolio provide more congestion relief in Future 2 than in Future 1, resulting in larger APC savings.

Zone	Future 1			Future 2		
	2028 (in 2024 $M)	2033 (in 2024 $M)	40-yr NPV (in 2024 $M)	2028 (in 2024 $M)	2033 (in 2024 $M)	40-yr NPV (in 2024 $M)
AEPW	$84.84	$93.93	**$1,499.83**	$55.29	$78.57	**$1,332.92**
EMDE	$20.70	$29.05	**$491.49**	$36.31	$36.17	**$559.21**
GMO	$0.54	$6.22	**$124.65**	$2.25	$6.43	**$120.46**
GRDA	$40.56	$58.67	**$998.94**	$48.93	$59.10	**$965.96**
KACY	($7.39)	($9.10)	**($149.47)**	($7.23)	($8.78)	**($143.70)**
KCPL	$6.83	$2.92	**$25.59**	($1.07)	($3.45)	**($65.32)**
LES	$12.25	$9.90	**$141.44**	$7.83	$8.43	**$133.62**
MIDW	($3.66)	$0.49	**$28.37**	($6.42)	$0.11	**$34.46**
NPPD	$14.33	$20.16	**$341.23**	$12.52	$11.40	**$170.80**
OKGE	$7.11	$29.65	**$571.91**	$40.69	$42.45	**$666.10**
OPPD	$31.60	$45.00	**$763.84**	$26.28	$45.46	**$799.94**
SPRM	$8.21	$18.35	**$334.85**	$16.47	$24.46	**$418.70**
SPS	$719.92	$392.11	**$4,430.62**	$650.69	$341.95	**$3,749.44**
SUNC	($9.59)	($5.92)	**($73.26)**	($14.37)	($3.38)	**$2.74**
SWPA	$3.77	$10.00	**$185.99**	$2.49	$8.43	**$160.24**
UMZ	$2,834.39	$4,483.00	**$77,661.80**	$3,028.67	$4,915.15	**$85,543.43**
WERE	$39.12	$78.72	**$1,417.07**	$40.17	$75.06	**$1,336.81**
WFEC	($5.94)	($6.83)	**($110.10)**	($5.40)	($7.63)	**($129.22)**
Total	**$3,797.60**	**$5,256.30**	**$88,684.80**	**$3,934.08**	**$5,629.93**	**$95,656.60**

Table 7.1: APC Savings by Zone

7.1.3 REDUCTION OF EMISSION RATES AND VALUES

Additional transmission may result in a lower fossil-fuel burn (for example, less coal-intensive generation), resulting in less SO_2, NOX, and CO_2 emissions. Such a reduction in emissions is a benefit that is already monetized through the APC savings metric, based on the assumed allowance prices for these effluents. Note that neither ITP future assumes any allowance prices for CO_2.

7.1.4 SAVINGS DUE TO LOWER ANCILLARY SERVICE NEEDS AND PRODUCTION COSTS

Ancillary services, such as spinning reserves, ramping (up/down), regulation, and 10-minute quick start are essential for the reliable operation of the electrical system. Additional transmission can decrease the ancillary services costs by: (a) reducing the ancillary services quantity needed, or (b) reducing the procurement costs for that quantity.

The ancillary services needs in SPP are determined according to SPP's market protocols and do not change based on transmission. Therefore, the savings associated with the "quantity" effect are assumed to be zero.

The costs of providing ancillary services are captured in the APC metrics. The production cost simulations set aside the static levels of resources to provide regulation and spinning reserves. As a result, the benefits related to "procurement cost" effect are already included as a part of the APC savings presented in this report.

7.1.5 AVOIDED OR DELAYED RELIABILITY PROJECTS

SPP staff reviewed potential reliability needs to determine if the upgrades proposed for economic or policy reasons defer or replace any reliability upgrades. The avoided or delayed reliability project benefit represents the costs associated with these additional reliability upgrades that would otherwise have to be pursued.

To calculate the avoided or delayed reliability project benefit for the recommended portfolio, SPP staff analyzed and identified the ability of economic projects to avoid or delay a base reliability project in the optimization milestone.

For 2024 ITP, the reliability project proposed to rebuild the Dawson County to Lewis and Clark 115 kV line was overlapped with the proposed economic project to build the new Dawson County to Williston 230 kV line. The benefit associated with the avoidance of the Dawson County to Lewis and Clark 115 kV rebuild is $92.7 million.

Zone	Future 1: Reference Case	Future 2: Emerging Technologies
	(in 2024 $M)	(in 2024 $M)
AEPW	$6.03	$6.03
EMDE	$0.67	$0.67
GMO	$1.13	$1.13
GRDA	$0.63	$0.63
KACY	$0.27	$0.27
KCPL	$2.17	$2.17
LES	$0.43	$0.43
MIDW	$0.22	$0.22

Zone	Future 1: Reference Case	Future 2: Emerging Technologies
	(in 2024 $M)	(in 2024 $M)
NPPD	$1.93	$1.93
OKGE	$4.02	$4.02
OPPD	$1.56	$1.56
SPRM	$0.39	$0.39
SPS	$3.41	$3.41
SUNC	$0.66	$0.66
SWPA	$0.22	$0.22
UMZ	$64.97	$64.97
WERE	$2.93	$2.93
WFEC	$1.06	$1.06
TOTAL	**$92.71**	**$92.71**

Table 7.2: Avoided or Delayed Reliability Projects

7.1.6 CAPACITY COST SAVINGS DUE TO REDUCED ON-PEAK TRANSMISSION LOSSES

Transmission line losses result from the interaction of line materials with the energy flowing over the line. This constitutes an inefficiency inherent to all standard conductors. Line losses across the SPP system are directly related to system impedance. Transmission projects often reduce losses during peak load conditions, which lowers the costs associated with additional generation capacity needed to meet the capacity requirements.

SPP staff calculated the capacity cost savings for the recommended portfolio based on the on-peak losses estimated in the base reliability powerflow model. SPP staff then multiplied the loss reductions by 112% to estimate the reduction in installed capacity requirements. The value of capacity savings is monetized by applying a net cost of new entry (net CONE) of $85.61/kW-yr in 2018 dollars. The net Cost of New Entry (CONE) value was obtained from Attachment AA Resource Adequacy–Attachment AA Section 14 of the tariff. SPP assumed the net CONE to grow at an inflation rate of 2.0% for each study year, $26.7 million for 2028, and $19.4 million for 2033. Table 7.3 displays the associated capacity savings for each zone in each study year and the 40-year PV.

Base Reliability			
Zone	2028 (nom. $m)	2033 (nom. $m)	40-yr NPV (in 2024 $M)
AEPW	$0.1	($0.0)	**($1.0)**
EMDE	$0.3	$0.3	**$3.9**
GMO	$0.2	$0.2	**$2.5**
GRDA	$0.0	$0.1	**$1.3**
KACY	$0.0	$0.0	**$0.0**

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Base Reliability			
Zone	**2028 (nom. $m)**	**2033 (nom. $m)**	**40-yr NPV (in 2024 $M)**
KCPL	$0.2	$0.2	**$2.4**
LES	$0.1	$0.2	**$2.2**
MIDW	$0.0	($0.0)	**($0.2)**
NPPD	$2.7	$2.5	**$31.9**
OKGE	$0.4	($0.1)	**($3.5)**
OPPD	$0.4	$0.6	**$7.9**
SPRM	($0.1)	($0.1)	**($1.2)**
SPS	$14.1	$7.1	**$59.4**
SUNC	($0.1)	($0.0)	**($0.4)**
SWPA	$0.1	$0.1	**$1.3**
UMZ	$7.9	$8.3	**$109.8**
WERE	$0.3	$0.1	**$1.3**
WFEC	$0.1	$0.0	**$0.3**
Total	**$26.7**	**$19.4**	**$217.9**

Table 7.3: On-Peak Loss Reduction and Associated Capacity Cost Savings

7.1.7 ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

The assumed benefit of mandated reliability project is the metric that monetizes the benefits of reliability projects required to meet compliance and mitigate SPP criteria violations. The regional benefits are assumed to be equal to the 40-year PV of ATRRs of the projects, totaling $4,411.8 million in 2024 dollars.

The system reconfiguration approach to allocate zonal benefits utilizes the powerflow models to measure incremental flows shifted onto the existing system during an outage of the proposed reliability upgrade. SPP staff uses this as a proxy for how much each upgrade reduces flows on the existing transmission facilities in each zone. SPP staff used the results from the production cost simulations to determine hourly flow direction on the upgrades and applied as weighting factors for the powerflow results.

Table 7.4 summarizes the system reconfiguration analysis results and the benefit allocation factors for different voltage levels. The table shows the overall zonal benefits calculated by applying these allocation factors.

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Mandated Reliability Benefits									
SPP-wide Benefit	< 100 kV $0	100–300 kV $649			> 300 kV $3,762			All NTC Projects $4,412	
Zone	100% SR	66.7% SR	33.3% LRS	Wtd. Avg.	33.3% SR	66.7% LRS	Wtd. Avg.	Overall Allocation	Benefit (in 2024 $M)
AEPW	0.00%	1.1%	15.6%	6.0%	3.0%	15.6%	11.4%	**10.6%**	**$467.58**
EMDE	0.00%	3.2%	1.8%	2.7%	2.2%	1.8%	1.9%	**2.0%**	**$90.1**
GMO	0.00%	1.5%	3.1%	2.0%	2.9%	3.1%	3.0%	**2.9%**	**$126.4**
GRDA	0.00%	0.4%	3.3%	1.4%	1.4%	3.3%	2.7%	**2.5%**	**$109.7**
KACY	0.00%	1.3%	0.8%	1.2%	0.2%	0.8%	0.6%	**0.7%**	**$31.2**
KCPL	0.00%	1.6%	5.4%	2.9%	1.0%	5.4%	3.9%	**3.8%**	**$166.0**
LES	0.00%	1.6%	1.1%	1.4%	0.7%	1.1%	1.0%	**1.1%**	**$46.5**
MIDW	0.00%	0.2%	0.7%	0.4%	0.7%	0.7%	0.7%	**0.6%**	**$27.8**
NPPD	0.00%	10.5%	6.3%	9.1%	6.5%	6.3%	6.4%	**6.8%**	**$299.2**
OKGE	0.00%	4.7%	12.5%	7.3%	8.9%	12.5%	11.3%	**10.7%**	**$470.9**
OPPD	0.00%	4.3%	5.7%	4.8%	2.3%	5.7%	4.6%	**4.6%**	**$202.9**
SPRM	0.00%	2.1%	1.0%	1.7%	1.4%	1.0%	1.1%	**1.2%**	**$52.8**
SPS	0.00%	8.8%	10.0%	9.2%	12.1%	10.0%	10.7%	**10.5%**	**$461.5**
SUNC	0.00%	5.9%	2.0%	4.6%	1.9%	2.0%	2.0%	**2.4%**	**$104.3**
SWPA	0.00%	1.1%	1.1%	1.1%	1.3%	1.1%	1.2%	**1.2%**	**$52.1**
UMZ	0.00%	49.9%	16.5%	38.8%	49.7%	16.5%	27.6%	**29.2%**	**$1,288.6**
WERE	0.00%	0.9%	9.0%	3.6%	2.9%	9.0%	7.0%	**6.5%**	**$286.6**
WFEC	0.00%	0.9%	4.2%	2.0%	0.8%	4.2%	3.1%	**2.9%**	**$127.5**
Total	**0.00%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**$4,411.8**

Table 7.4: Mandated Reliability Benefits

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7.1.8 BENEFIT FROM MEETING PUBLIC POLICY GOALS

This metric represents the economic benefit provided by the transmission upgrades for facilitating public policy goals. In this study, the scope is limited to meeting public policy goals related to renewable energy. Systemwide benefits are assumed to be equal to the cost of policy projects.

Since SPP staff identified no policy projects as a part of the recommended portfolio, the associated benefits are estimated to be zero.

7.1.9 MITIGATION OF TRANSMISSION OUTAGE COSTS

The standard production cost simulations used to estimate APC savings assume that transmission lines and facilities are available during all hours of the year, ignoring the added congestion-relief and production cost benefits of new transmission facilities during the planned and unplanned outages of existing transmission facilities.

To estimate the incremental savings associated with the mitigation of transmission outage costs, the production cost simulations can be augmented for a realistic level of transmission outages. Due to the significant effort needed to develop these augmented models for each case, SPP used the findings from the RCAR II study to calculate this benefit metric for the consolidated portfolio as a part of this ITP Assessment. In the RCAR analysis, adding a subset of historical transmission outage events to the production cost simulations increased the APC savings by 3.34%.[45,46] Applying this ratio to the APC savings estimated for the recommended portfolio translates to a 40-year PV of benefits of $2,921.9 million for Future 1 and $3,143.9 million for Future 2 in 2024 dollars. These benefits are allocated based upon the load ratio share of the region.

Table 7.5 shows the outage mitigation benefits allocated to each SPP zone.

Zone	Future 1: Reference Case (in 2024 $M)	Future 2: Emerging Technologies (in 2024 $M)
AEPW	$438.4	$471.7
EMDE	$50.2	$54.1
GMO	$85.8	$92.3
GRDA	$93.9	$101.0
KACY	$23.6	$25.4
KCPL	$151.4	$162.9
LES	$31.6	$34.0
MIDW	$19.2	$20.7
NPPD	$177.7	$191.2
OKGE	$350.1	$376.7
OPPD	$183.6	$197.5
SPRM	$27.4	$29.4
SPS	$373.0	$401.3
SUNC	$57.2	$61.5
SWPA	$31.6	$34.0
UMZ	$456.8	$491.5
WERE	$253.5	$272.8
WFEC	$116.8	$125.7
TOTAL	**$2,921.9**	**$3,143.9**

Table 7.5: Transmission Outage Cost Mitigation Benefits by Zone

45 SPP Regional Cost Allocation Review Report, October 8, 2013 (pp. 36–37)

46 As directed by ESWG, SPP will periodically review historical outage data and update additional APC savings ratio for future studies. Although the outage data was not updated for the 2015 ITP10, it is being reviewed and updated for the RCAR II assessment.

7.1.10 INCREASED WHEELING THROUGH AND OUT REVENUES

Increasing the Available Transfer Capacity (ATC) with a neighboring region improves import and export opportunities for the SPP footprint. Increased interregional transmission capacity that allows for increased through and out transactions will also increase SPP wheeling revenues.

To estimate how increased ATC could affect the wheeling services sold, SPP staff analyzed the historical long-term firm transmission service request (TSR) allowed by the historical NTC projects and compared them against the ATC increase in the 2014 powerflow models estimated based on a First Contingency Incremental Transfer Capability (FCITC) analysis. As summarized in Table 7.6, the NTC projects that have been put in-service under SPP's highway/byway cost allocation methodology enabled 13 long-term TSRs to be sold between 2010 and 2014. The TSRs remain active for 2024. The amount of capacity granted for these TSRs add up to 1,402 MW. The associated wheeling revenues are estimated to be $56 million annually based on current SPP tariff rates. The results of the FCITC analysis are summarized in Table 7.7. The export ATC increase in the 2014 powerflow models is calculated to be 1,402 MW, which is comparable to the amount of firm capacity granted for the incremental TSRs sold historically for 2024.

Point of Delivery	Number of Firm Point-to-Point Service Requests	MW Capacity Granted	2014 Wheeling Revenues in (2023 $million)			
			Sch 7 Zonal	Sch 11 Reg-Wide	Sch 11 Thru & Out Zonal	TOTAL
AECI	8	608	$10.29	$9.17	$5.29	$24.75
Entergy	5	504	$9.88	$7.60	$4.38	$21.87
SaskPower	3	650	$38.93	$9.81	$5.65	$54.39
Ameren	1	1	$0.03	$0.02	$0.01	$0.05
Total:	17	1,763	$59.12	$26.60	$15.33	$101.05

Table 7.6: Estimated Wheeling Revenues from Incremental Long-Term TSRs Sold (2010-2014)

Export ATC in 2014 Base Case	1,630 MW
Export ATC in 2014 Change Case	2,943 MW
Increase in Export ATC due to NTCs	1,313 MW
Incremental TSRs Sold due to NTCs	1763 MW
TSRs Sold as a Percent of Increase in Export ATC	134%

Table 7.7: Historical Ratio of TSRs Sold Against Increase in Export ATC

SPP staff utilized the 2028 and 2033 base reliability powerflow models for the FCITC analysis on the consolidated portfolio. The ratio of TSRs sold as a percent of increase in export ATC is capped at 100%, as incremental TSR sales would not be expected to exceed the amount of increase in export ATC. The recommended portfolio increased the export ATC by 9 MW in 2028 and 2,376 MW in 2033. Applying the historical ratio suggests the recommended portfolio could enable incremental TSRs by the same amount, generating additional wheeling revenues of $0.7-$198.4 million annually.

The 40-year NPV of benefits is estimated to be$4.6 billion. These benefits are allocated based on the current revenue sharing method in the tariff. Table 7.8 shows the distribution of wheeling revenue benefits for each SPP zone.

Zone	Future 1		
	2028 (nom. $m)	2033 (nom. $m)	40-yr NPV 2024 $M
AEPW	$0.2	$49.3	$1,142.8
EMDE	$0.0	$3.8	$88.0
GMO	$0.0	$5.0	$115.4
GRDA	$0.0	$6.5	$151.2
KACY	$0.0	$0.4	$9.3
KCPL	$0.0	$7.8	$181.0
LES	$0.0	$2.7	$62.9
MIDW	$0.0	$0.9	$20.9
NPPD	$0.1	$16.7	$385.8
OKGE	$0.1	$23.9	$552.7
OPPD	$0.0	$4.9	$114.4
SPRM	$0.0	$1.2	$28.3
SPS	$0.1	$22.9	$530.9
SUNC	$0.0	$3.5	$82.0
SWPA	$0.0	$2.2	$50.3
UMZ	$0.1	$20.6	$478.4
WERE	$0.1	$19.1	$441.5
WFEC	$0.0	$6.9	$160.0
Total	**$0.7**	**$198.4**	**$4,596.0**

Table 7.8: 2024 ITP Wheeling Revenue Benefits by Zone

7.1.11 MARGINAL ENERGY LOSSES BENEFIT

The standard production cost simulations used to estimate APC do not reflect the impact of transmission upgrades on the MWh quantity of transmission losses. To make run-times more manageable, the load in the production cost simulations is "grossed up" for average transmission losses for each zone. These loss assumptions do not change with additional transmission. Therefore, the traditional APC metric does not capture the benefits from reduced MWh quantity of losses.

APC savings due to such energy loss reductions can be estimated by post-processing the marginal loss component (MLC) of the LMPs from simulation results and applying a methodology[47] for marginal energy losses, which accounts for losses on generation and market imports. The 40-year PV of benefits is estimated to be $3.5 billion in Future 1 and $4.1 billion in Future, as shown in Table 7.9 below.

[47] As described in the Benefit Metric Manual

Zone	Future 1 Reference Case	Future 2 Emerging Technologies
	40-yr NPV (in 2024 $M)	40-yr NPV (in 2024 $M)
AEPW	$345.4	$1,204.7
EMDE	$16.7	$126.9
GMO	$126.7	$97.0
GRDA	$414.2	$194.4
KACY	$31.1	$36.2
KCPL	$576.6	$212.0
LES	$53.9	$334.4
MIDW	($19.9)	($47.8)
NPPD	($27.1)	($257.8)
OKGE	$230.3	$793.2
OPPD	$295.0	$104.1
SPRM	$78.6	($23.0)
SPS	$543.3	$922.7
SUNC	($237.2)	($130.5)
SWPA	$46.4	$22.7
UMZ	$814.0	$317.8
WERE	$96.1	$102.4
WFEC	$80.9	$92.2
TOTAL	**$3,465.0**	**$4,101.5**

Table 7.9: Energy Losses Benefit by Zone

7.1.12 SUMMARY

Table 7.10 through Table 7.13 summarize the 40-year PV of the estimated benefit metrics and costs and the resulting benefit-to-cost ratios for each SPP zone.

For the region, SPP estimates the benefit-to-cost ratio to be 9.0 in Future 1 and 9.7 in Future 2. The higher benefit-to-cost ratio in Future 2 is driven by the APC savings due to higher congestion relief.

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Future 1: Reference Case											
	Present Value of 40-yr Benefits for the 2028-2067 Period (in 2024 $M)										
Zone	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Total Benefits	Present Value of 40-yr ATRRs (in 2024 $M)	Established Benefit/ Cost Ratio
AEPW	$1,499.83	$6	($1.02)	$467.6	$0	$444.45	$1,143	$345.40	$3,905	$2,107	**1.9**
EMDE	$491.49	$1	$3.90	$90.1	$0	$50.93	$88	$16.67	$742	$366	**2.0**
GMO	$124.65	$1	$2.48	$126.4	$0	$86.99	$115	$126.72	$584	$392	**1.5**
GRDA	$998.94	$1	$1.32	$109.7	$0	$95.18	$151	$414.18	$1,771	$229	**7.7**
KACY	($149.47)	$0	$0.00	$31.2	$0	$23.92	$9	$31.12	($54)	$92	**(0.6)**
KCPL	$25.59	$2	$2.37	$166.0	$0	$153.44	$181	$576.63	$1,107	$752	**1.5**
LES	$141.44	$0	$2.21	$46.5	$0	$32.02	$63	$53.87	$339	$151	**2.3**
MIDW	$28.37	$0	($0.19)	$27.8	$0	$19.48	$21	($19.88)	$77	$77	**1.0**
NPPD	$341.23	$2	$31.90	$299.2	$0	$180.19	$386	($27.13)	$1,213	$703	**1.7**
OKGE	$571.91	$4	($3.45)	$470.9	$0	$354.96	$553	$230.33	$2,181	$1,393	**1.6**
OPPD	$763.84	$2	$7.86	$202.9	$0	$186.10	$114	$295.01	$1,572	$584	**2.7**
SPRM	$334.85	$0	($1.20)	$52.8	$0	$27.74	$28	$78.57	$522	$136	**3.8**
SPS	$4,430.62	$3	$59.42	$461.5	$0	$378.13	$531	$543.32	$6,407	$1,298	**4.9**
SUNC	($73.26)	$1	($0.43)	$104.3	$0	$57.97	$82	($237.24)	($66)	$229	**(0.3)**
SWPA	$185.99	$0	$1.34	$52.1	$0	$32.01	$50	$46.38	$368	$93	**4.0**
UMZ	$77,661.80	$65	$109.80	$1,288.6	$0	$463.08	$478	$814.00	$80,881	$1,504	**53.8**
WERE	$1,417.07	$3	$1.31	$286.6	$0	$257.03	$442	$96.14	$2,503	$1,137	**2.2**
WFEC	($110.10)	$1	$0.29	$127.5	$0	$118.45	$160	$80.91	$378	$369	**1.0**
Total	**$88,685**	**$92.7**	**$218**	**$4,412**	**$0**	**$2,962**	**$4,596**	**$3,465**	**$104,430**	**$11,612**	**9.0**

Table 7.10: Future 1 Zonal - Estimated 40-year PV of Benefit Metrics and Costs

Future 1: Reference Case											
State	Present Value of 40-yr Benefits for the 2028-2067 Period (in 2024 $M)								Total Benefits	Present Value of 40-yr ATRRs (in 2024 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits			
Arkansas	$462	$2	$0	$169	$0	$143	$318	$115	$1,210	$630	1.9
Colorado	$92	$0	$0	$2	$0	$1	$1	$1	$97	$2	41.6
Iowa	$9,629	$8	$14	$160	$0	$57	$59	$101	$10,028	$187	53.7
Kansas	$1,341	$5	$2	$548	$0	$444	$661	$166	$3,167	$1,941	1.6
Louisiana	$195	$1	($0)	$61	$0	$58	$149	$45	$509	$275	1.9
Minnesota	$2,280	$2	$3	$38	$0	$14	$14	$24	$2,375	$44	53.8
Missouri	$1,002	$3	$7	$368	$0	$255	$340	$555	$2,530	$1,290	2.0
Montana	$3,105	$3	$4	$52	$0	$19	$19	$33	$3,234	$60	53.8
Oklahoma	$2,073	$8	($1)	$822	$0	$685	$1,238	$806	$5,631	$2,633	2.1
Nebraska	$2,070	$5	$43	$562	$0	$403	$567	$330	$3,980	$1,453	2.7
New Mexico	$1,781	$2	$24	$212	$0	$176	$246	$236	$2,678	$598	4.5
North Dakota	$41,310	$35	$58	$685	$0	$246	$254	$433	$43,022	$800	53.8
South Dakota	$20,422	$17	$29	$339	$0	$122	$126	$214	$21,269	$396	53.7
Texas	$2,921	$4	$34	$394	$0	$339	$603	$407	$4,700	$1,303	3.6
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	$0	-	-
TOTAL	**$88,685**	**$93**	**$218**	**$4,412**	**$0**	**$2,962**	**$4,596**	**$3,465**	**$104,430**	**$11,612**	**9.0**

Table 7.11: Future 1 State - Estimated 40-year PV of Benefit Metrics and Costs

Future 2: Emerging Technologies											
Zone	Present Value of 40-yr Benefits for the 2028-2067 Period (in 2024 $M)								Total Benefits	Present Value of 40-yr ATRRs (in 2024 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits			
AEPW	$1,332.92	$6	($1.02)	$467.6	$0	$479.39	$1,143	$1,204.68	$4,632	$2,107	**2.2**
EMDE	$559.21	$1	$3.90	$90.1	$0	$54.93	$88	$126.87	$924	$366	**2.5**
GMO	$120.46	$1	$2.48	$126.4	$0	$93.83	$115	$97.03	$557	$392	**1.4**
GRDA	$965.96	$1	$1.32	$109.7	$0	$102.66	$151	$194.41	$1,526	$229	**6.7**
KACY	($143.70)	$0	$0.00	$31.2	$0	$25.80	$9	$36.18	($41)	$92	**(0.4)**
KCPL	($65.32)	$2	$2.37	$166.0	$0	$165.51	$181	$212.00	$664	$752	**0.9**
LES	$133.62	$0	$2.21	$46.5	$0	$34.53	$63	$334.43	$615	$151	**4.1**
MIDW	$34.46	$0	($0.19)	$27.8	$0	$21.01	$21	($47.80)	$56	$77	**0.7**
NPPD	$170.80	$2	$31.90	$299.2	$0	$194.35	$386	($257.83)	$826	$703	**1.2**
OKGE	$666.10	$4	($3.45)	$470.9	$0	$382.86	$553	$793.17	$2,866	$1,393	**2.1**
OPPD	$799.94	$2	$7.86	$202.9	$0	$200.73	$114	$104.10	$1,431	$584	**2.5**
SPRM	$418.70	$0	($1.20)	$52.8	$0	$29.92	$28	($22.95)	$506	$136	**3.7**
SPS	$3,749.44	$3	$59.42	$461.5	$0	$407.85	$531	$922.67	$6,135	$1,298	**4.7**
SUNC	$2.74	$1	($0.43)	$104.3	$0	$62.53	$82	($130.53)	$121	$229	**0.5**
SWPA	$160.24	$0	$1.34	$52.1	$0	$34.53	$50	$22.71	$321	$93	**3.5**
UMZ	$85,543.43	$65	$109.80	$1,288.6	$0	$499.49	$478	$317.77	$88,303	$1,504	**58.7**
WERE	$1,336.81	$3	$1.31	$286.6	$0	$277.24	$442	$102.37	$2,449	$1,137	**2.2**
WFEC	($129.22)	$1	$0.29	$127.5	$0	$127.76	$160	$92.22	$380	$369	**1.0**
Total	**$95,657**	**$92.7**	**$218**	**$4,412**	**$0**	**$3,195**	**$4,596**	**$4,101**	**$112,271**	**$11,612**	**9.7**

Table 7.12: Future 2 Zonal - Estimated 40-year PV of Benefit Metrics and Costs

Future 2: Emerging Technologies											
State	Present Value of 40-yr Benefits for the 2028-2067 Period (in 2024 $M)								Total Benefits	Present Value of 40-yr ATRRs (in 2024 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Trans-mission Outage Costs	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits			
Arkansas	$429	$2	$0	$169	$0	$155	$318	$345	$1,417	$630	2.2
Colorado	$102	$0	$0	$2	$0	$1	$1	$0	$105	$2	45.2
Iowa	$10,606	$8	$14	$160	$0	$62	$59	$39	$10,948	$187	58.6
Kansas	$1,309	$5	$2	$548	$0	$479	$661	$84	$3,088	$1,941	1.6
Louisiana	$174	$1	($0)	$61	$0	$62	$149	$157	$604	$275	2.2
Minnesota	$2,512	$2	$3	$38	$0	$15	$14	$9	$2,593	$44	58.7
Missouri	$1,079	$3	$7	$368	$0	$275	$340	$310	$2,382	$1,290	1.8
Montana	$3,420	$3	$4	$52	$0	$20	$19	$13	$3,531	$60	58.7
Oklahoma	$2,034	$8	($1)	$822	$0	$739	$1,238	$1,476	$6,316	$2,633	2.4
Nebraska	$2,012	$5	$43	$562	$0	$435	$567	$185	$3,808	$1,453	2.6
New Mexico	$1,500	$2	$24	$212	$0	$190	$246	$393	$2,567	$598	4.3
North Dakota	$45,502	$35	$58	$685	$0	$266	$254	$169	$46,970	$800	58.7
South Dakota	$22,494	$17	$29	$339	$0	$131	$126	$83	$23,220	$396	58.6
Texas	$2,484	$4	$34	$394	$0	$366	$603	$839	$4,723	$1,303	3.6
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	$0	-	-
TOTAL	**$95,657**	**$93**	**$218**	**$4,412**	**$0**	**$3,195**	**$4,596**	**$4,101**	**$112,271**	**$11,612**	**9.7**

Table 7.13: Future 2 State - Estimated 40-year PV of Benefit Metrics and Costs

7.2 RATE IMPACTS[48]

SPP staff computed the rate impact to an average retail residential ratepayer in the SPP footprint for the consolidated portfolio. Rate impact costs[49] and benefits[50] are allocated to the average retail residential ratepayer based on an estimated residential consumption of 1,000 kilowatt hours (kWh) per month. SPP staff used the benefits and costs for the 2033 study year to calculate rate impacts. All 2033 benefits and costs are shown in 2024 dollars, discounting at a 2.0% inflation rate.

SPP staff subtracted the retail residential rate impact benefit from the retail residential rate impact cost to obtain a net rate impact cost by zone. If the net rate impact cost is negative, it indicates a net benefit to the zone. The rate impact costs and benefits are shown in Table 7.14 through Table 7.17. There is a monthly net benefit for the average SPP residential ratepayer of $10.55 for Future 1. There is a monthly net benefit for the average SPP residential ratepayer of $11.47 for Future 2.

Future 1 Rate Impacts by Zone					
Zone	One-Year ATRR Costs 2033 ($thousands)	One-Year Benefit 2033 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2033$)
AEPW	$176,359.30	$70,522.15	$3.53	$1.41	$2.12
EMDE	$29,909.45	$25,214.14	$5.23	$4.41	$0.82
GMO	$32,833.07	$5,363.22	$3.36	$0.55	$2.81
GRDA	$19,147.10	$39,737.55	$1.79	$3.72	($1.93)
KACY	$7,701.98	($7,465.80)	$2.87	($2.78)	$5.65
KCPL	$62,948.05	$2,714.52	$3.65	$0.16	$3.50
LES	$12,603.93	$8,452.32	$3.51	$2.35	$1.15
MIDW	$6,429.45	$700.86	$2.94	$0.32	$2.62
NPPD	$59,084.91	$17,371.65	$2.92	$0.86	$2.06
OKGE	$116,594.74	($22,064.12)	$2.93	($0.55)	$3.48
OPPD	$49,053.26	$38,227.30	$2.69	$2.10	$0.59
SPRM	$11,355.51	$15,105.24	$3.65	$4.85	($1.20)
SPS	$109,070.04	$326,995.43	$3.42	$10.27	($6.84)
SUNC	$19,141.02	($4,618.95)	$2.95	($0.71)	$3.67
SWPA	$7,614.47	$7,751.46	$2.12	$2.16	($0.04)
UMZ	$123,241.09	$3,756,021.07	$2.34	$71.19	($68.85)
WERE	$92,122.31	$66,969.54	$3.19	$2.32	$0.87
WFEC	$30,874.12	($5,272.90)	$2.32	($0.40)	$2.72
TOTAL	**$966,083.80**	**$4,341,724.69**	**$3.02**	**$13.56**	**($10.55)**

Table 7.14: Future 1 - Retail Residential Rate Impacts by Zone

[48] Rate impacts will be updated as necessary based upon the final portfolio and approved project need dates.
[49] For the purposes of calculating ATRRs for projects assigned to non-SPP TOs, the costs were allocated on a region-wide basis to existing pricing zones, like projects that are 100% regionally funded (300 kV and above).
[50] APC savings are the only benefit included in the rate impact calculations, although Reduction of Emission Rates & Values and Savings due to Lower Ancillary Service Needs & Production Costs are included in the APC calculation.

Future 1 Rate Impacts by State					
State	One-Year ATRR Costs 2033 ($thousands)	One-Year Benefit 2033 ($thousands)	Rate Impact-Cost	Rate Impact-Benefit	Net Impact (2033$)
Arkansas	$52,656.44	$16,463.34	$3.27	$1.02	$2.25
Colorado	$192.05	$4,465.94	$2.45	$57.05	($54.60)
Iowa	$15,303.00	$465,693.17	$2.34	$71.10	($68.77)
Kansas	$159,360.11	$61,530.38	$3.20	$1.23	$1.96
Louisiana	$22,982.51	$9,190.19	$3.53	$1.41	$2.12
Minnesota	$3,618.37	$110,277.25	$2.34	$71.19	($68.85)
Missouri	$107,183.79	$48,265.50	$3.75	$1.69	$2.06
Montana	$4,927.78	$150,184.13	$2.34	$71.19	($68.85)
Oklahoma	$220,362.32	$48,313.93	$2.87	$0.63	$2.24
Nebraska	$121,937.37	$103,886.16	$2.86	$2.44	$0.42
New Mexico	$50,225.60	$131,983.02	$3.24	$8.53	($5.28)
North Dakota	$65,553.97	$1,997,889.75	$2.34	$71.19	($68.85)
South Dakota	$32,450.65	$987,675.95	$2.34	$71.11	($68.78)
Texas	$109,329.83	$205,905.98	$3.42	$6.45	($3.03)
Wyoming	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL	**$966,083.80**	**$4,341,724.69**	**$3.02**	**$13.56**	**($10.55)**

Table 7.15: Future 1 - Retail Residential Rate Impacts by State

Future 2 Rate Impacts by Zone					
Zone	One-Year ATRR Costs 2033 ($thousands)	One-Year Benefit 2033 ($thousands)	Rate Impact-Cost	Rate Impact-Benefit	Net Impact (2033$)
AEPW	$176,359.30	$61,242.94	$3.53	$1.23	$2.31
EMDE	$29,909.45	$30,734.20	$5.23	$5.37	($0.14)
GMO	$32,833.07	$5,234.39	$3.36	$0.54	$2.83
GRDA	$19,147.10	$37,567.75	$1.79	$3.52	($1.72)
KACY	$7,701.98	($7,214.44)	$2.87	($2.69)	$5.55
KCPL	$62,948.05	($2,360.24)	$3.65	($0.14)	$3.79
LES	$12,603.93	$7,297.06	$3.51	$2.03	$1.48
MIDW	$6,429.45	$241.55	$2.94	$0.11	$2.83
NPPD	$59,084.91	$10,115.90	$2.92	$0.50	$2.42
OKGE	$116,594.74	($27,472.15)	$2.93	($0.69)	$3.61
OPPD	$49,053.26	$38,844.84	$2.69	$2.13	$0.56
SPRM	$11,355.51	$19,504.34	$3.65	$6.26	($2.62)
SPS	$109,070.04	$285,468.98	$3.42	$8.96	($5.54)
SUNC	$19,141.02	($2,552.08)	$2.95	($0.39)	$3.35
SWPA	$7,614.47	$6,422.56	$2.12	$1.79	$0.33
UMZ	$123,241.09	$4,116,713.77	$2.34	$78.03	($75.69)
WERE	$92,122.31	$63,477.85	$3.19	$2.20	$0.99
WFEC	$30,874.12	($6,108.89)	$2.32	($0.46)	$2.78
TOTAL	**$966,083.80**	**$4,637,158.34**	**$3.02**	**$14.49**	**($11.47)**

Table 7.16: Future 2 - Retail Residential Rate Impacts by Zone

Future 2 Rate Impacts by State					
State	One-Year ATRR Costs 2033 ($thousands)	One-Year Benefit 2033 ($thousands)	Rate Impact-Cost	Rate Impact-Benefit	Net Impact (2033$)
Arkansas	$52,656.44	$13,608.33	$3.27	$0.85	$2.43
Colorado	$192.05	$4,887.86	$2.45	$62.44	($59.99)
Iowa	$15,303.00	$510,410.44	$2.34	$77.93	($75.60)
Kansas	$159,360.11	$57,737.94	$3.20	$1.16	$2.04
Louisiana	$22,982.51	$7,980.96	$3.53	$1.23	$2.31
Minnesota	$3,618.37	$120,867.23	$2.34	$78.03	($75.69)
Missouri	$107,183.79	$53,986.87	$3.75	$1.89	$1.86
Montana	$4,927.78	$164,606.39	$2.34	$78.03	($75.69)
Oklahoma	$220,362.32	$36,397.09	$2.87	$0.47	$2.40
Nebraska	$121,937.37	$99,935.10	$2.86	$2.35	$0.52
New Mexico	$50,225.60	$114,95.81	$3.24	$7.42	($4.18)
North Dakota	$65,553.97	$2,189,748.17	$2.34	$78.03	($75.69)
South Dakota	$32,450.65	$1,082,516.38	$2.34	$77.94	($75.61)
Texas	$109,329.83	$179,539.76	$3.42	$5.62	($2.20)
Wyoming	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL	**$966,083.80**	**$4,637,158.34**	**$3.02**	**$14.49**	**($11.47)**

Table 7.17: Future 2 - Retail Residential Rate Impacts by Zone

7.3 FINAL RELIABILITY ASSESSMENT

7.3.1 METHODOLOGY

SPP staff incorporated all projects in the 2024 ITP consolidated portfolio and model adjustments identified during solution development into the base reliability and short-circuit models. SPP staff performed a contingency analysis of equivalent scope to the analysis described in sections 4.2.1 and 4.2.2 of the ITP Manual to determine if the selected projects caused new reliability violations.

7.3.1.1 *SHORT-CIRCUIT MODEL*

A proxy automatic sequencing fault calculation (ASCC) short-circuit analysis was performed on the 2024 ITP year-two summer maximum fault current model to find percent increases in fault currents in relation to the base case model on which the needs assessment was performed. SPP staff added all consolidated portfolio projects expected to alter or need zero sequence data to the model regardless of their in-service dates. After performing this analysis, SPP staff found that 640 of the 11,132 buses monitored experienced a 5% increase in fault current.

7.3.2 SUMMARY

7.3.2.1 *BASE RELIABILITY MODELS*

SPP reviewed the resulting thermal and voltage violations and through invalidation, identified new violations that would require additional projects. To do so, SPP staff used methods such as reactive device setting adjustments, model updates, identification of invalid contingencies, non-load-serving buses and facilities not under SPP's functional control. However, SPP identified violations directly caused by projects included in the 2024 ITP consolidated portfolio. SPP developed additional projects to resolve these violations and included them in the final portfolio. The in-service dates for these added projects were determined based on the staging of the portfolio project that contributed to the violation the new project is solving.

The Spencer to Wisdom 69 kV line rebuild is one of the projects added to the portfolio due to the final reliability assessment. It addresses the same need as the Wisdom 161/69 kV transformer, without causing any new violations. For this reason, SPP staff recommends the 69 kV line from Spencer to Wisdom rebuild to receive an NTC in place of the Wisdom transformer.

7.3.2.2 *SHORT-CIRCUIT MODEL*

The results of the final reliability assessment for the short-circuit models showed 33 of the 640 buses were exceeding common breaker duty ratings of 20 kA and 40 kA. The subsequent short-circuit analysis in the next ITP study cycle will confirm whether the duty ratings are exceeded given the latest modeling assumptions. The addition of the consolidated portfolio did not show any new fault-interrupting equipment to have its duty ratings exceeded by the maximum available fault current.

7.3.2.3 *ASSET MANAGEMENT PROJECTS*

During the final reliability assessment, SPP staff analyzed asset management projects submitted by TOs to ensure that they did not create new violations. The analysis confirmed that the projects listed in Table 7.18 did not introduce any new violations.

Description	Projected In-Service Date
Aquarius - Litchfield North 69 kV Rebuild	7/1/2026
Litchfield - Pitnac Tap - Mulberry 69 kV Rebuild	7/1/2026

Table 7.18 Asset Management Projects Studied in 2024 ITP

7.3.3 CONCLUSION

The final reliability assessment showed 10 new reliability violations caused by the 2024 ITP recommended portfolio that required additional project recommendations. Because these projects were identified so late in the study process, they are not considered in the Benefit Metrics or Rate Impacts calculations. Figure 7.1 and Table 7.19 specifies the projects included in the final portfolio to address these violations.

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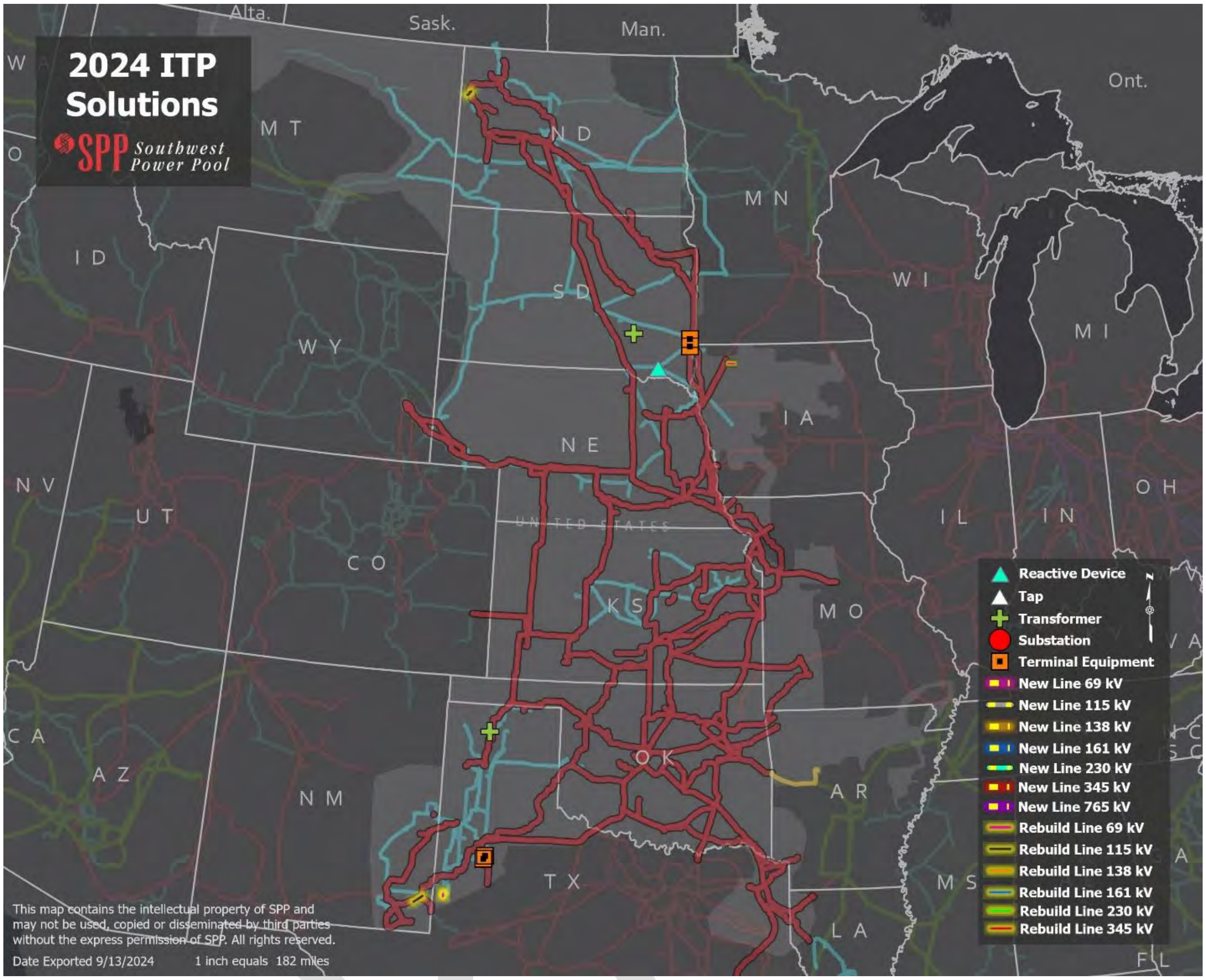

Figure 7.1: Final Reliability Assessment Projects

Project Description	Portfolio Project Driving Need	Area	Project Type	Conceptual Cost Estimate
Moore County 230/115 kV Ckt 2 Transformer	Moore County - XIT 230 kV Ckt 1 New Line	SPS	Added Project	$13,022,086
Maddox - Pearle 115 kV Rebuild	Lynch - Medanos 115 kV Ckt 1 New Line	SPS	Added Project	$15,972,706
Lubbock East - Lubbock South 115 kV Terminal Equipment	N/A	SPS	Added Project	$956,448 (SCE)
Gaines-Riley-Mid America-Mid-Denver Tap 69 kV Rebuild	Denver - Mid America 69 kV San Andreas - Seminole 115 kV Tap Intersection	SPS	Portfolio Project Update	$7,339,941
Spencer - Wisdom 69 kV Rebuild	Wisdom 161/69 kV Transformer	WAPA	Added Project	$1,020,175
Williston - Ren 115 kV Rebuild	Sanderson - Pioneer 115 kV Ckt 1 New Line	WAPA	Added Project	$9,398,047
Lincoln- Sioux Falls 115 kV Terminal Equipment	ZPC: Sioux Falls South Dakota Area 115 kV System Reconfiguration	WAPA	Project Update	$373,343

Harrisburg - Lincoln 115 kV Rebuild	ZPC: Sioux Falls South Dakota Area 115 kV System Reconfiguration	EREC	Added Project	$3,755,542
Mount Vernon 115 kV Capacitor	ZPC: Hanson County 115 kV System Reconfiguration	WAPA	Added Project	$373,343
Hutchinson 115 kV Capacitor	ZPC: Marion South Dakota Area 115 kV Voltage Conversion	EREC	Project Update	$1,091,240
			Total:	$53,302,871

Table 7.19: Final Reliability Assessment Projects

7.4 SENSITIVITY ANALYSIS

SPP staff performed sensitivity analysis on the 2024 ITP consolidated portfolio to assess how well the system performs under a range of conditions. The information in the section 7.4.1 shows the variables adjusted for the sensitivity analysis. Section 7.4.2 shows the results of those changes.

7.4.1 SENSITIVITY INPUT DATA

Sensitivity models were developed to assess how versatile the portfolio is as it handles a range of uncertainties. SPP staff created economic sensitivity models to adjust some of the initial assumptions. Adjusted assumptions include load demand amounts, Henry Hub gas prices, renewable resource capacity, planned battery storage amounts. Sensitivities were applied to all modeled areas, not just SPP.

Figure 7.2 shows the Henry Hub gas prices for the Base case and high/low sensitivities. Adjustments were based on the 2023 EIA (Energy Information Administration) AEO (Annual Energy Outlook) High and Low Oil and Gas Supply cases.[51] The High Price case reflects limited supply, increasing the cost of natural gas. Alternatively, the Low Price case reflects ample supply, therefore reducing natural gas prices.

[51] EIA Annual Energy Outlook 2023: https://www.eia.gov/outlooks/aeo/

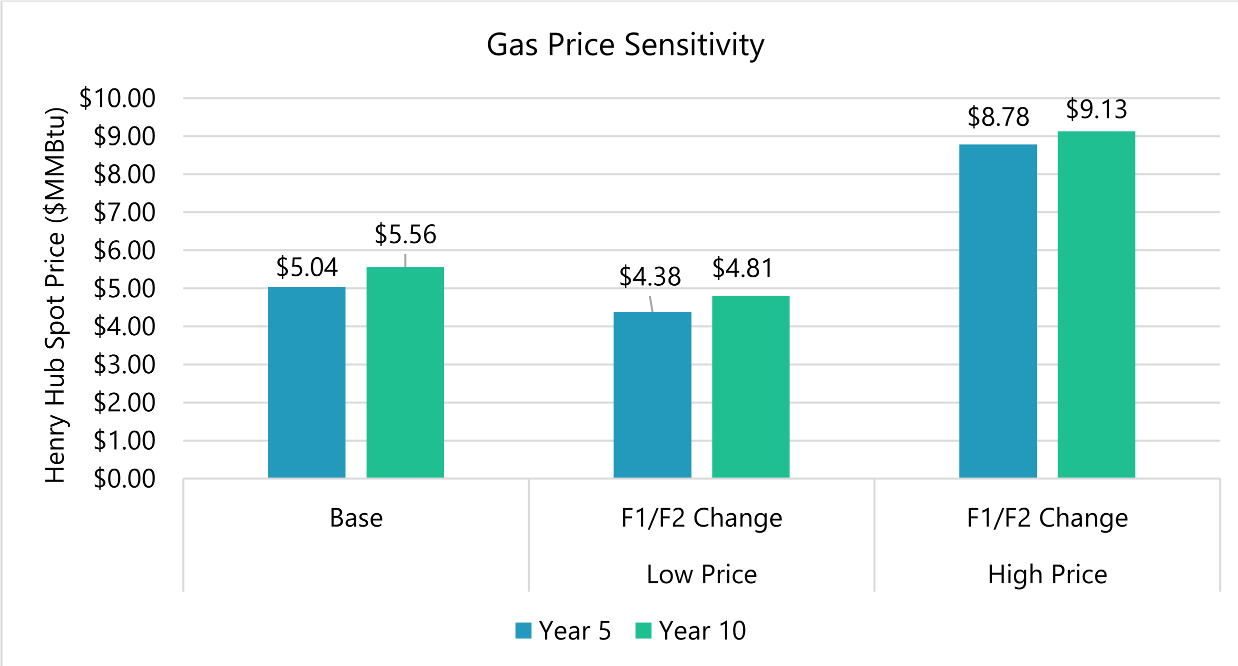

Figure 7.2: Gas Price Sensitivity

Figure 7.3 shows the demand levels base case and sensitivities. Adjustments were based on the 2023 EIA AEO High and Low Economic Growth cases.

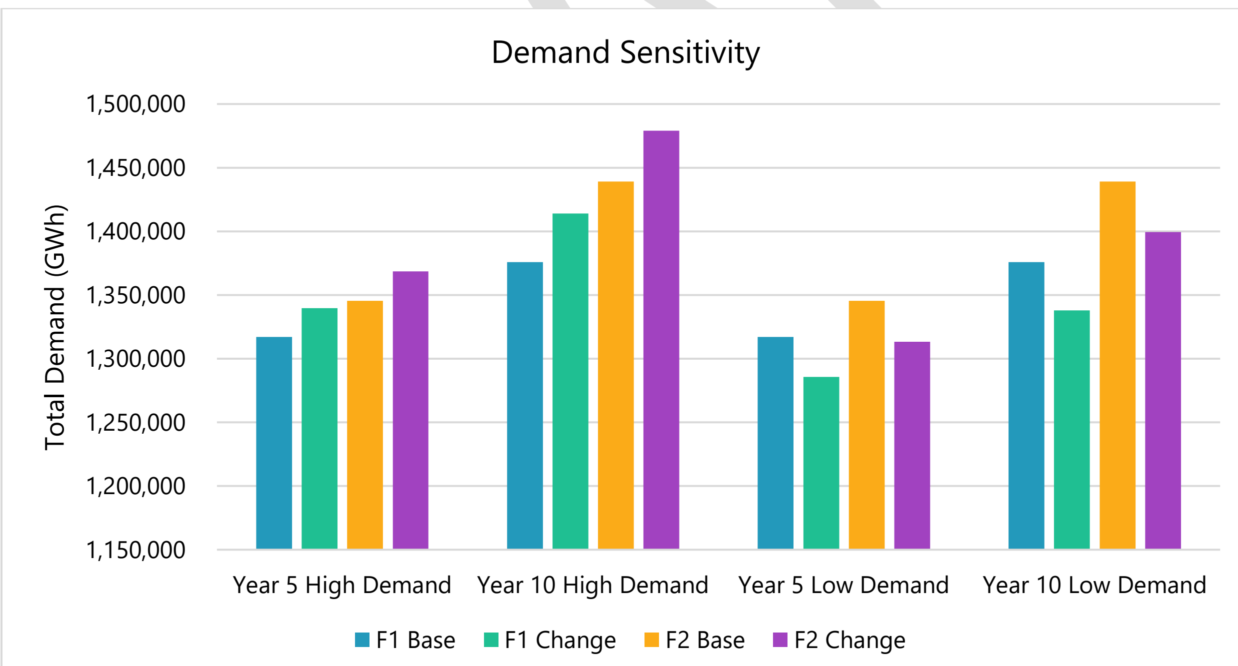

Figure 7.3: Demand Sensitivity

Figure 7.4 and Figure 7.5 show the capacity change for solar and wind in the base case and sensitivities (reflected by total annual energy changes). Adjustments were based on the 2023 EIA AEO High and Low Zero-Carbon Technology cost cases. It should be noted that there is no change from year five base to change wind values. This is due to the EIA data used for the study having very little deviation for this period.

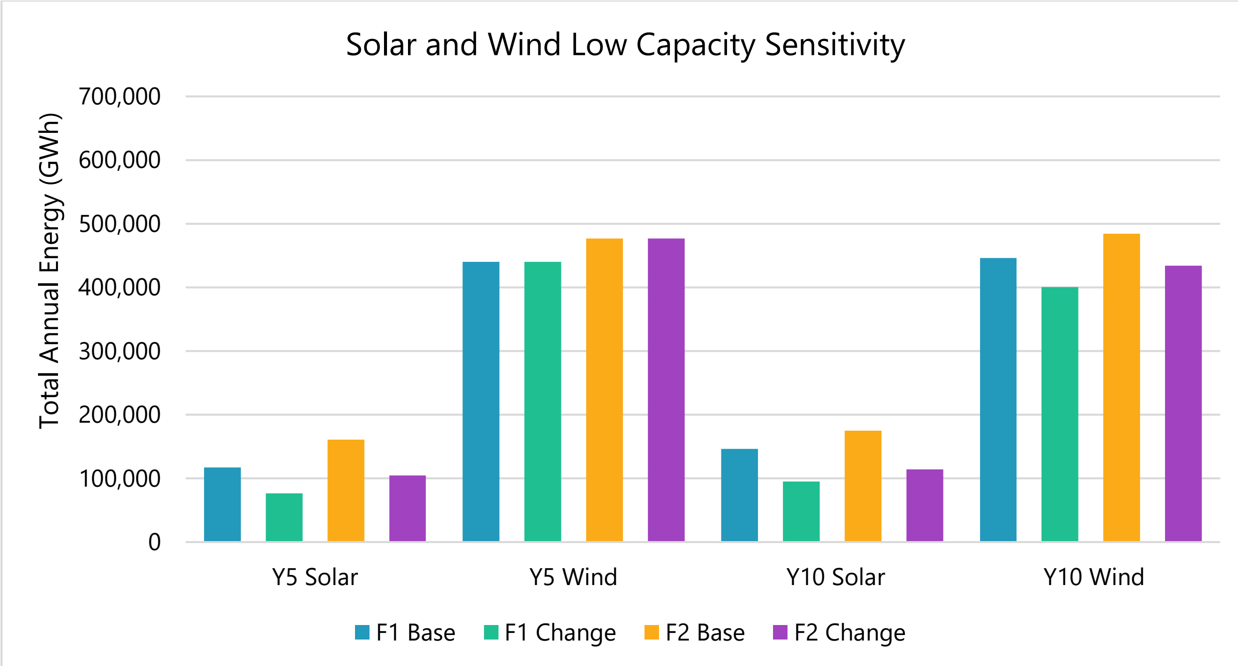

Figure 7.4: Solar and Wind Low-Capacity Sensitivity

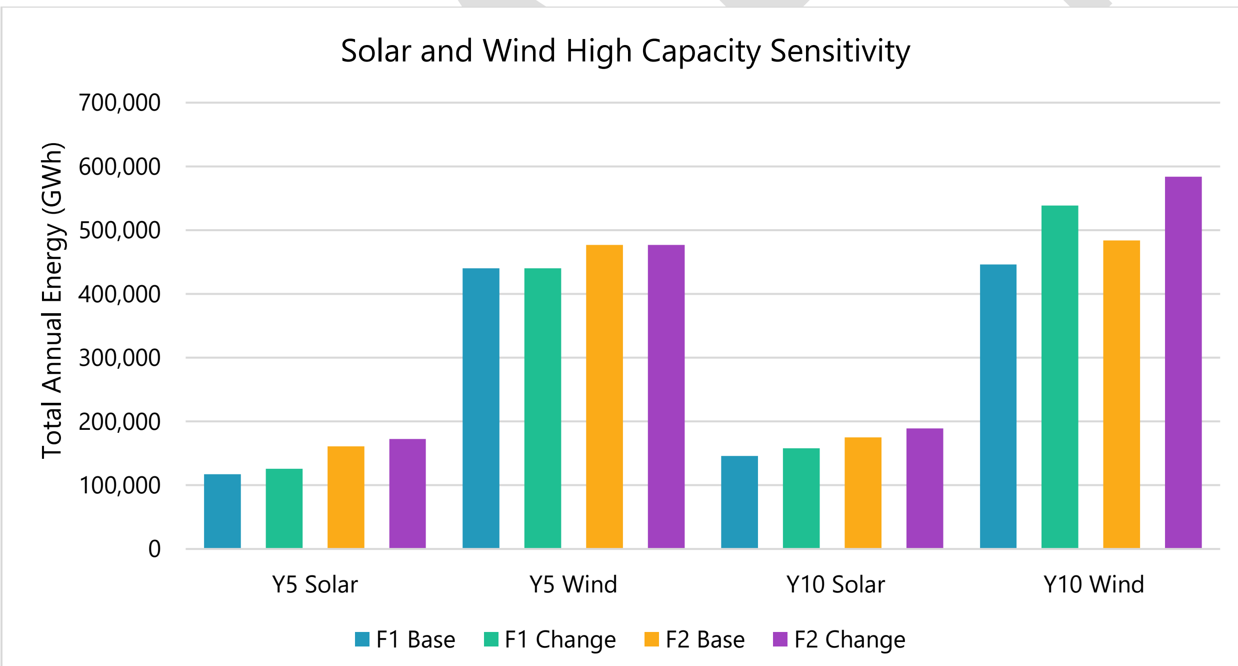

Figure 7.5: Solar and Wind High-Capacity Sensitivity

Figure 7.6 describes the amount of planned battery storage that was turned off for the sensitivity. This sensitivity turned off all planned battery storage in each year and future.

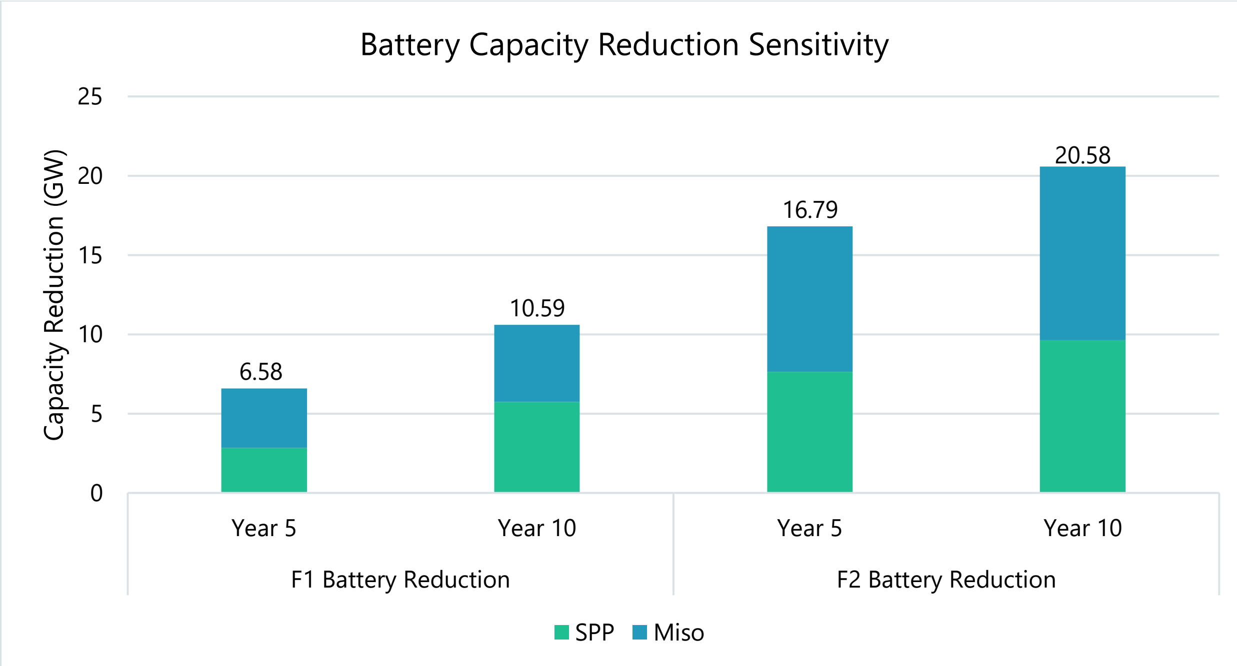

Figure 7.6: Battery Sensitivity

7.4.2 SENSITIVITY RESULTS

SPP tested the 2024 ITP portfolio under each sensitivity. SPP staff used both futures when testing each sensitivity to show the range of benefits provided by each portfolio under the alternative forecasts.

Benefit ranges for each sensitivity are shown alongside the expected portfolio costs with a +/- 30% range to cost applied. The following sensitivity results are reported on a model with relaxed emergency energy constraints and include the entire 2024 ITP portfolio. Results are indicative of the expected range of APC benefits that the 2024 ITP portfolio will have in each future for the differing sensitivities. The future case differing the most from the expected range for each sensitivity was used in Figure 7.7 below. The economic portfolio cost shown is representative of all economic projects and projects that share economic and reliability benefits for the multi-variable portfolio.

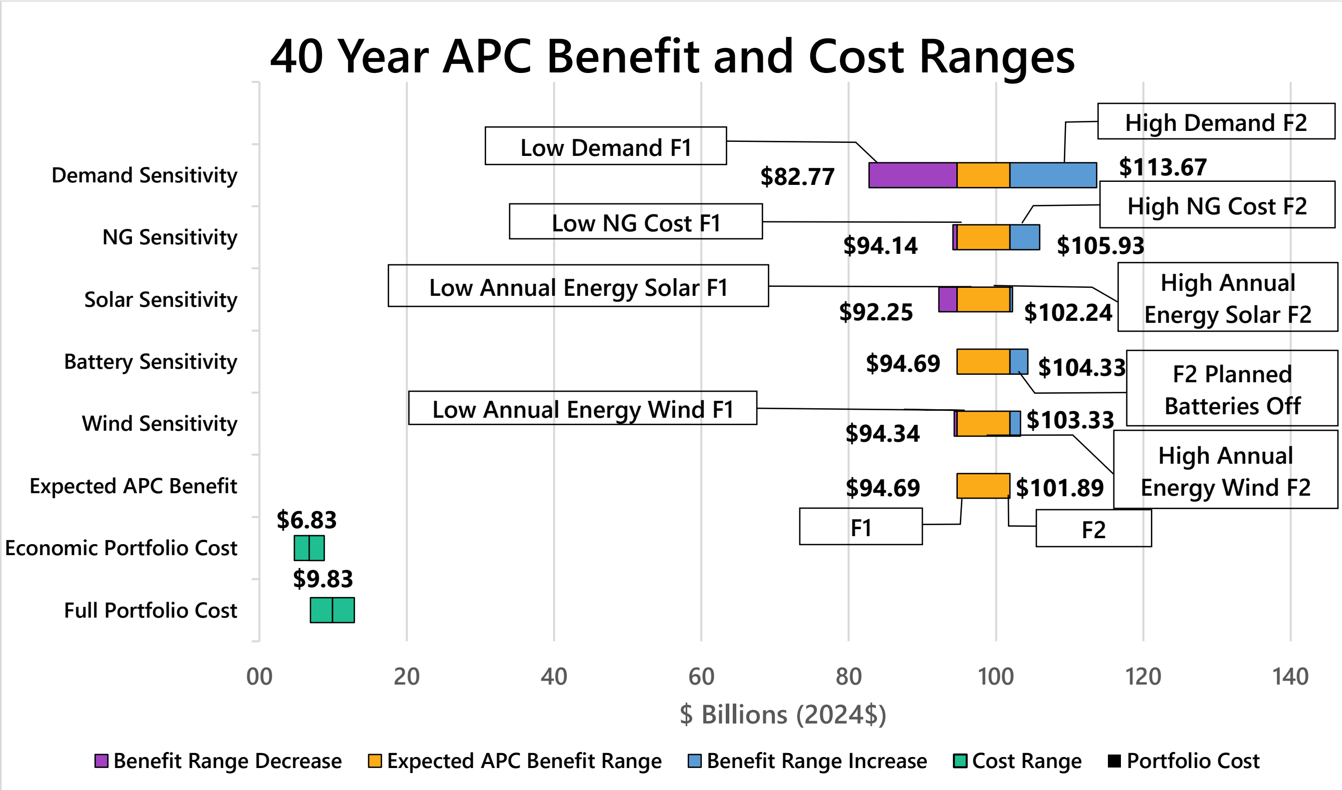

Figure 7.7: Sensitivity Analysis APC Benefit ($Billions)

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8 NTC RECOMMENDATIONS

SPP makes NTC recommendations for projects included in the consolidated portfolio based on results from the staging process and SPP Business Practice 7060. If financial expenditure is required within four years from Board approval, the project is generally recommended by SPP staff for an NTC or NTC-C. To determine the date when financial expenditure is required, SPP staff subtracts the project's lead time from its need date. Expected lead times for transmission projects are determined using historical data on construction timelines from SPP's project tracking process. NTC-Cs are issued for projects with an operating voltage greater than 100 kV and a Study Estimate greater than $20 million.

Table 8.1 below shows SPP's NTC recommendations when considering staging results, expected lead times and other qualitative information related to the recommended projects.

Description	Need Date	Lead Time (months)	Projected In-Service Date	NTC/ NTC-C[52]
15th Ave - Watertown 115 kV Rebuild	6/1/2031	48	6/1/2031	NTC
Ainsworth - Bassett 115 kV Ckt 1 New Line	6/1/2029	42	6/1/2029	NTC-C
Alliance - Snake Creek 115 kV Rebuild	1/1/2025	30	5/12/2027	TBD
Alliance - Snake Creek 115 kV Terminal Upgrade	Date of NTC Issuance	18	5/12/2026	TBD
Antelope - Holt County 345 kV Ckt 1 New Line	1/1/2025	48	11/12/2028	NTC-C
Aurora - Central City 115 kV Ckt 1 New Line	6/1/2026	42	5/12/2028	NTC
Aurora - Reeds Spring 161 kV Rebuild	12/1/2025	36	11/12/2027	NTC-C
Aurora H.T. - Monett 161 kV Ckt 1 Rebuild	Date of NTC Issuance	30	5/12/2027	NTC-C
Beckham County - Potter 345 kV New Line	11/12/2029	60	11/12/2029	NTC-C
Belfield - Maurine - New Underwood - Laramie River 345 kV New Line	1/1/2025	60	11/12/2029	NTC-C
Bismarck - East Bismarck 115 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Blackberry - Neosho 345 kV Rebuild	1/1/2036	48	1/1/2036	
Branson North - Branson Northwest -North Branson - Reed Springs 161 kV Rebuild	12/1/2025	30	5/12/2027	NTC
Branson North - Ozark Dam 161 kV Ckt 1 Rebuild	12/1/2025	30	5/12/2027	NTC
Brown - Colbert 138 kV Terminal Equipment	1/1/2030	18	1/1/2030	NTC
Buffalo Flats - Delaware 345 kV New Line	12/1/2028	60	11/12/2029	NTC-C
Bull Shoals - Midway Jordan 161 kV Rebuild	1/1/2030	30	5/12/2027	TBD
Butler - Midian 138 kV Rebuild	1/1/2028	30	1/1/2028	NTC

[52] A blank in this column indicates that no NTC or NTC-C will be issued.

Description	Need Date	Lead Time (months)	Projected In-Service Date	NTC/ NTC-C[52]
Butler South - Tallgrass 138 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Catoosa 161/138 kV Transformer	1/1/2025	24	11/12/2026	NTC
CDC East - Tulsa North 138 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Chadron - Dunlap 115 kV Ckt 1 Rebuild	1/1/2034	36	1/1/2034	
Channing 230 kV Capacitor	6/1/2025	24	11/12/2026	NTC
Chisholm - Maize - Evans Energy Center North 138 kV Ckt 1 Rebuild	1/1/2032	42	1/1/2032	NTC-C
Colbert 138 kV Capacitor	6/1/2029	24	6/1/2029	NTC
Compton Ridge - Roark Creek, Table Rock - Nixa, Reeds Spring - Branson Northwest 161 kV Line Taps	12/1/2025	24	11/12/2026	TBD
Conway - Kirby 115 kV Terminal Upgrade	Date of NTC Issuance	18	5/12/2026	NTC
Crane Creek - Robinson Lake 115 kV New Line	1/1/2028	42	5/12/2028	NTC
Dawson County - Williston 230 kV Ckt 1 New Line	6/1/2025	42	5/12/2028	NTC-C
Delaware - Monett 345 kV Ckt 1 New Line	12/1/2025	60	11/12/2029	NTC-C
Denver - Mid America 69 kV San Andreas - Seminole 115 kV Tap Intersection	6/1/2025	24	11/12/2026	NTC
Edwardsville 161/115 kV Transformer	Date of NTC Issuance	24	11/12/2026	NTC
Ellisville - Simpson 115 kV New Line, Zahl 115 kV Capacitor	6/1/2025	42	5/12/2028	NTC
Elm Creek - Tobias 345 kV New Line	12/1/2028	48	12/1/2028	NTC-C
Evans Energy Center North - Halstead 138 kV Ckt 1 New Line	1/1/2045	48	1/1/2045	
Farber - Sumner County No. 10 Belle Plain 138 kV Rebuild	1/1/2025	30	5/12/2027	NTC-C
Finstad - Logan 345 kV New Line, Leland Olds - Logan 345 kV Voltage Conversion	12/1/2032	60	12/1/2032	NTC-C
Finstad - Satterwaite 115 kV New Line	1/1/2028	42	5/12/2028	NTC
Frankford - Quaker 115 kV Rebuild	6/1/2025	30	5/12/2027	NTC
Gaines – Riley - Mid America - Mid-Denver Tap 69 kV Rebuild*	11/12/2026	30	11/12/2026	NTC
Gering Tap - Morrill 115 kV Ckt 1 Rebuild	1/1/2036	36	1/1/2036	
Gering Tap - Scotts Bluff 115 kV Ckt 1 Rebuild	1/1/2025	30	5/12/2027	TBD
Grapevine - Kingsmill 115 kV New Line	6/1/2025	42	5/12/2028	NTC

* FRA project

Description	Need Date	Lead Time (months)	Projected In-Service Date	NTC/ NTC-C[52]
Hanson County 115 kV System Reconfiguration	6/1/2025	36	11/12/2027	NTC-C
Harrisburg – Lincoln 115 kV Rebuild*	5/12/2027	30	5/12/2027	NTC
Holcomb - Sidney 345 kV Ckt 1 New Line	Date of NTC Issuance	60	11/12/2029	NTC-C
Hoskins - Stanton North 115 kV Rebuild	1/1/2026	30	5/12/2027	NTC
Hutchinson 115 kV Capacitor*	11/12/2027	24	11/12/2027	NTC
Iron House - Texaco 115 kV Ckt 1 New Line	6/1/2025	42	5/12/2028	NTC
Kingsbury County 115kV Voltage Conversion	6/1/2025	30	5/12/2027	NTC-C
Lamar 161/69 kV Ckt 2 Transformer	1/1/2036	30	1/1/2036	
Lawrence Energy Center Unit 3 - Lawrence Hill 115 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Lincoln – Sioux Falls 115 kV Terminal Equipment*	5/12/2027	18	5/12/2027	NTC
Logan - Magic City 230 kV Ckt 1 New Line	12/1/2032	60	12/1/2032	NTC-C / TBD
Lubbock East - Lubbock South 115 kV Terminal Equipment*	6/1/2025	18	5/12/2026	NTC
Lynch - Medanos 115 kV Ckt 1 New Line	12/1/2028	42	12/1/2028	NTC-C
Maddox - Pearle 115 kV Rebuild*	12/1/2028	36	12/1/2028	NTC
Madison South Dakota Area 115 kV System Reconfiguration	12/31/2025	36	12/31/2025	NTC
Marion South Dakota Area 115 kV Voltage Conversion	6/1/2025	36	11/12/2027	NTC-C
Martin City (East) - Martin City (West) 161 kV Terminal Equipment	1/1/2025	18	5/12/2026	NTC
Maud Tap 138 kV Terminal Upgrade	1/1/2025	18	5/12/2026	NTC
Monett - North Branson 345 kV Ckt 1 New Line	12/1/2025	48	11/12/2028	NTC-C
Moore County - Xit 230 kV Ckt 1 New Line	6/1/2025	42	5/12/2028	NTC-C
Moore County 230/115 kV Ckt 2 Transformer*	5/12/2028	24	5/12/2028	NTC-C
Morrill - Snake Creek 115 kV Ckt 1 Rebuild	1/1/2025	30	5/12/2027	TBD
Mount Vernon 115 kV Capacitor*	11/12/2027	24	11/12/2027	NTC
Muskogee - Tahlequah 161 kV Rebuild, Muskogee - Fort Smith 345 kV Conversion/New Line53	11/12/2024	48	11/12/2028	NTC-C
N Reeds Spring - S Reeds Spring 161 kV Rebuild	12/1/2025	30	5/12/2027	NTC
Nashua 345/161 kV Ckt 2 Transformer	Date of NTC Issuance	24	11/12/2026	NTC-C
Ozark Dam - Forsyth North - Ozark South 161 kV Voltage Conversion	12/1/2025	30	5/12/2027	NTC-C

* FRA project

[53] Project added to the final portfolio after the final consolidated portfolio was aggregated

Description	Need Date	Lead Time (months)	Projected In-Service Date	NTC/ NTC-C[52]
Patent Gate - Pioneer 345 kV Ckt 1 New Line	4/1/2025	48	11/12/2028	NTC-C
Phantom - Crossroads - Potter 765 kV Ckt 1 New Line	1/1/2025	60	11/12/2029	NTC-C
Pioneer - Sanderson 115 kV Ckt 1 New Line	1/1/2028	42	5/12/2028	NTC
Ren - Williston 115 kV Rebuild*	5/12/2028	30	5/12/2028	NTC
Roadrunner 345/115 kV Ckt 2 Transformer	6/1/2025	24	11/12/2026	NTC
Roadrunner 345/115 kV Ckt 3 Transformer	1/1/2025	24	11/12/2026	NTC
S1260 161 kV Breaker Replacement	6/1/2025	18	5/12/2026	
S3458 - S3740 345 kV Ckt 2 New Line	1/1/2025	48	11/12/2028	NTC-C
Sioux Falls South Dakota Area 115 kV System Reconfiguration	6/1/2025	30	5/12/2027	NTC-C
Spencer - Wisdom 69 kV Rebuild*	12/1/2025	30	5/12/2027	NTC
Spring Brook - Twelve Mile 345 kV Ckt 1 New Line	4/1/2032	48	4/1/2032	NTC-C
Sub 1209 - Sub 1250 161 kV Rebuild	6/1/2028	30	6/1/2028	NTC-C
Sub 1209 - Sub 1358 161 kV Rebuild	6/1/2028	30	6/1/2028	NTC
Sub 1250 - Sub 1358 161 kV Rebuild	6/1/2028	30	6/1/2028	NTC
Tallgrass - Weaver 138 kV Rebuild	1/1/2025	30	5/12/2027	NTC
Tinker 138 kV Two Breaker Replacements	6/1/2025	18	5/12/2026	NTC
Tulsa North 345/138 kV Ckt 2 Transformer	1/1/2025	24	11/12/2026	NTC
W Banks 345/115 kV Transformer	1/1/2032	60	1/1/2032	NTC-C
Wisdom 161/69 kV Transformer	12/1/2025	24	11/12/2026	

Table 8.1: 2024 ITP NTC Recommendations

DK

9 GLOSSARY

Acronym	Name
ABB	ABB Group licenses the PROMOD enterprise software SPP uses for economic simulations
APC	Adjusted production cost = Production Cost $ + Purchases $-Sales $
ARR	Auction Revenue Rights
ATC	Available transfer capacity
BAA	Balancing Authority Area
BAU	Business as usual
B/C	Benefit-to-Cost Ratio
BES	Bulk-Electric System
CLR	Cost per loading relief
CT	Combustion turbine
CVR	Cost per voltage relief
DPNS	Delivery Point Network Study
DPP	Detailed Project Proposal
E&C	Engineering and construction cost
ERCOT	Electric Reliability Council of Texas (ERCOT)
EHV	Extra-high voltage
ESWG	Economic Studies Working Group
FCITC	First contingency incremental transfer capacity
FERC	Federal Energy Regulatory Commission
FTLO	For the loss of
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GOF	Generator outlet facilities
GW	Gigawatt
GWh	Gigawatt hour
HV	High voltage
IFTS	Interruption of firm transmission service
IRP	Integrated resource plan
IS	Integrated System, which includes the Western Area Power Administration's Upper Great Plains Region (Western-UGP), Basin Electric Power Cooperative, and the Heartland Consumers Power District
ITP	Integrated Transmission Planning

Acronym	Name
ITP Manual	Integrated Transmission Planning Manual
kV	Kilovolt
LMP	Locational Marginal Price = the market-clearing price for energy at a given Price Node equivalent to the marginal cost of serving demand at the Price Node, while meeting SPP Operating Reserve requirements
MISO	Midcontinent Independent System Operator
MTEP19	2019 MISO Transmission Expansion Plan
MTEP20	2020 MISO Transmission Expansion Plan
MTEP	MISO Transmission Expansion Plan
MDAG	Model Development Advisory Group
MMWG	Multi-regional Modeling Working Group
MOPC	Markets and Operations Policy Committee
MW	Megawatt
NERC	North American Electric Reliability Corporation
NITSA	Network Integration Transmission Service Agreement
NTC	Notifications to Construct
NREL	National Renewable Energy Laboratory
NCLL	Non-consequential load loss
PPA	Power Purchase Agreement
PST	Phase-shifting transformer
PU	Per unit
PV	Present value
RCAR	Regional Cost Allocation Review
RPS	Renewable portfolio standards
SASK	Saskatchewan Power
SCRD	Security Constrained Redispatch
SPC	Strategic Planning Committee
SPP OATT	SPP Open Access Transmission Tariff
TO	Transmission Owner
TSR	Transmission Service Request
TVA	Tennessee Valley Authority
TWG	Transmission Working Group
US EIA	United States Energy Information Administration
VSL	Voltage stability limit
ZPC	Zonal Planning Criteria

Table 9.1: Glossary

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA**

IN THE MATTER OF THE PETITION OF GEVO NET-ZERO 1, LLC TO HAVE KINGSBURY ELECTRIC COOPERATIVE, INC. ASSIGNED AS ITS ELECTRIC PROVIDER IN THE SERVICE AREA OF OTTER TAIL POWER COMPANY **AND** **IN THE MATTER OF THE PETITION OF DAKOTA RENEWABLE HYDROGEN, LLC TO HAVE KINGSBURY ELECTRIC COOPERATIVE, INC. ASSIGNED AS ITS ELECTRIC PROVIDER IN THE SERVICE AREA OF OTTER TAIL POWER COMPANY**	**STAFF'S SECOND SET OF DATA REQUESTS TO EAST RIVER ELECTRIC POWER COOPERATIVE INC.** **DOCKETS** **EL24-024 & EL24-025**

East River Electric Cooperative Inc.'s (East River) submits the following answers and responses to Staff's Second Set of Data Requests to East River Electric Power Cooperative Inc. (East River) in the dockets identified above:

2-1) Referring to East River's response to Otter Tail's data request 110(a), East River states:

"Without waiving said objections, costs attributable directly to the new load will be recovered from NZ1 / DRH at cost. Some of the transmission investment will be includable in SPP and the return on investment for those assets is specified in the East River Annual Transmission Revenue Requirement (ATRR) template filed with SPP and FERC, a public document. The portion of transmission that is not directly attributable to the load or that is not includable in SPP will be recovered through East River and KEC rates at cost."

a) Please quantify the costs attributable directly to the new load.

Answered by Mark Hoffman, East River Electric Power Cooperative, Inc.'s Chief Operations Officer:

Objection for the reasons the question is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waving said objection, [Trade Secret Begins] XXXXXXX [Trad Secret Ends]

b) Please quantify the transmission investment that will be includable in SPP.

Answered by Mark Hoffman:

Objection for the reasons the question is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

[Trade Secret Begins] XXXXXXXXX [Trad Secret Ends]

c) Please quantify the portion of the transmission that is not directly attributable to the load or that is not includable in SPP.

Answered by Mark Hoffman:

Objection for the reasons the question is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

[Trade Secret Begins] XXXXXXXXX [Trad Secret Ends]

2-2) Referring to East River's response to Otter Tail's data request 110(d), please provide a copy SPP's 2024 Integrated Transmission Plan (2024 ITP) and any associated documents that identify East River's proposed facilities and cost estimates which were included in the 2024 ITP. If a copy of the documents requested in this data request were produced in response to a previous data request, simply identify what data request response the documents have already been produced for.

Answered by Mark Hoffman:

Submitted with EL24-024 East River's Answers to Staff's DR1 to East River.

2-3) Referring to East River's response to Otter Tail's data request 110(d), please provide a copy East River's load connection transmission system study referenced in the response. If a copy of the document requested in this data request were produced in response to a previous data request, simply identify what data request response the documents have already been produced for.

Answered by Mark Hoffman:

Submitted with EL24-024 East River's Answers to Staff's DR1 to East River.

2-4) Referring to East River's response to Otter Tail's data request 111(a), East River states:

"SPP sets the transmission rates for the area and will determine how the East River ATRR for the upgrades is allocated between the zonal and regional transmission rates under the SPP Tariff. The allocation of the ATRR between the zonal and regional transmission rates will have a significant difference on rate impacts within the zone. Until SPP decides how to allocate the upgrades between the regional and zonal transmission rates, East River is unable to determine the exact SPP transmission rate impact."

a) Why does SPP need to decide the regional and zonal allocation for East River's proposed transmission upgrades? Does SPP's Tariff not clearly identify the cost allocation? Please explain.

Answered by Mark Hoffman:

Objection for the reasons the question is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waiving said objection, the SPP Tariff defines the cost allocation for facilities, and network upgrades at 115-kV will typically be allocated one third to the regional rate and two thirds to the zonal rates. However, our understanding is that SPP will perform a benefits test to ensure the facilities provide a regional benefit (i.e., support the bulk transmission system) to determine whether the costs should be allocated regionally.

b) When will SPP decide how to allocate the upgrades between regional and zonal transmission rates?

Answered by Mark Hoffman:

Objection for the reasons the question is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waiving said objection, Unknown. They may have already performed the benefits test as part of the ITP rate impact assessment, but East River has not been notified of their determination. We expect to be notified when we receive the Notification to Construct.

2-5) Referring to East River's response to Otter Tail's data request 111(a), East River states:

"For a high-level estimate of a possible rate impacts, the East River upgrades would increase East River's ATRR by approximately $6 million. That ATRR would likely be split with one third ($2 million) allocated to the SPP regional transmission rate and two thirds ($4 million) allocated to the zonal transmission rate (UMZ pricing zone). The revenue requirement for load in the UMZ would increase approximately $4.2 million."

a) Please provide workpapers, assumptions, and calculations used to quantify the ATRR impact provided above. If the information requested in this data request was provided in response to a previous data request, simply identify what data request response the information has already been provided for.

Answered by Mark Hoffman:

Objection for the reasons the question is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waiving said objection, because the ATRR will be based on facilities included in the Notification to Construct and on actual costs, a simple calculation was used to estimate the ATRR. The current ATRR to SPP Rate Base ratio was used as the basis for the ATRR estimate. That ratio for the 2023 True-Up ATRR was 14.62% (i.e., $29,719,690/$203,276,204). Applying that ratio to the SPP Rate Base, including the planned upgrades for the Kingsbury County area, provides an incremental increase in the ATRR of about $5.8 million.

$203,276,204 (2023 Rate Base)

*+$24,174,850 ($29,845,000 substation cost*0.81 substation allocator)*

*+$15,165,360 ($54,162,000 line cost *0.28-line allocator)*

$242,616,014 Estimated SPP Rate Base

**.01462 ATRR/Rate Base estimator*

$35,471,308 Estimated ATRR

-$29,719,690 2023 ATRR

$5,751,617 ATRR from Kingsbury County upgrades

**0.6666 assumed zonal allocation*

$3,834,411 ATRR impact to the zonal rate (rounded to $4 million)

The load of the UMZ is about 10 percent of the SPP footprint, so the regional component of the ATRR would add another $191,720 to the revenue requirement of load in the UMZ (rounded to $200,000).

b) If Otter Tail disagrees with the inclusion of certain facilities in East River's ATRR, can Otter Tail challenge the inclusion of those facilities at SPP and/or FERC? Please explain.

Answered by Mark Hoffman:

Objection for the reasons the question is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waiving said objection, Yes. The SPP ITP assessment is an open, public process with multiple opportunities for stakeholder input, feedback and formal challenge.

2-6) Referring to East River's response to Otter Tail's data request 111(a), East River states:

"The increased transmission revenue from NZ1 and the other new load in the area would be approximately $4.4 million. In summary, it appears the NZ1 Project and other new load will not adversely impact the rates to other customers."

a) Please identify the "other new load in the area" referenced in this statement. For each load identified, include the expected peak demand, load factor, and coincidence factor at the time of East River's system peak.

Answered by Mark Hoffman:

Objection for the reasons the question is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waiving said objection, in addition to the NZ1 load, additional dairy load and possibly digester loads are being considered in Kingsbury County. New dairy loads are expected to be in the 8.5 to 10 MW range with new digester loads up to 7.5 MW. The most certain dairy loads are in western Kingsbury County with an additional dairy expected in southeast Kingsbury County. Because these are loads that are not currently operating, we assume the loads will be similar to other dairy loads (high load factors) on the East River system.

b) Please provide workpapers, assumptions, and calculations used to quantify the increased transmission revenue from NZ1 and the other new load in the area. If the information requested in this data request was provided in response to a previous data request, simply identify what data request response the information has already been provided for.

Answered by Mark Hoffman:

Objection for the reasons the question is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waiving said objection, the transmission revenue from the new load was determined by multiplying the expected peaks of the new load which includes NZ1 45 MW, DRH 20 MW, and an additional 15 MW of new load as described in 2-6a by the current zonal rate transmission rate.

*(45 MW+20 MW+15 MW) * 1000 * $4.592677/kW-mo) *12 = $4,408,970.*

Daniel J. Brown, Attorney for East River, hereby objects to certain requests, as shown above.

Dated this 22nd day October, 2024.

East River Electric Power Cooperative, Inc.

By: /s/Daniel J. Brown

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF DAKOTA RENEWABLE HYDROGEN, LLC TO HAVE KINGSBURY ELECTRIC COOPERATIVE, INC. ASSIGNED AS ITS ELECTRIC PROVIDER IN THE SERVICE AREA OF OTTER TAIL POWER COMPANY	* * * * * * * * *	**EAST RIVER ELECTRIC POWERS COOPERATIVE'S ANSWERS TO STAFF'S FIRST SET OF DATA REQUESTS TO EAST RIVER ELECTRIC POWER COOPERATIVE INC.** **EL24-025**

East River Electric Power Cooperative, Inc. ("East River") submits the following answers and responses to Staff's First Set of Data Requests to East River:

1-1) Please provide a copy of all data requests East River received from any party and East River's responses to the data requests. This should be considered a continuing request.

Ok.

1-2) Please identify Dakota Renewable Hydrogen, LLC's (DRH) contracted minimum demand that Kingsbury Electric Cooperative (KEC), East River, and Basin Electric Cooperative (Basin) will serve. Provide a copy of any document that legally binds DRH to meet that minimum demand service requirement if such document is different than the Electric Service Agreement provided as Exhibit 3 to DRH's Petition. If the document is the Electric Service Agreement provided as Exhibit 3, please identify where the minimum demand is specified or explain how the Electric Service Agreement meets the minimum demand requirement in SDCL 49-34A-56.

Answered by Mark Hoffman, East River Electric Power Cooperative, Inc.'s Chief Operations Officer:

Objection for the reason the question of "identify where the minimum demand is specified or explain how the Electric Service Agreement meets the minimum demand requirement in SDCL 49-34A-56" is a legal question for the Commission determine.

Without waving said objection the document that binds DRH is the Electric Service Agreement ("ESA") entered into between DRH and KEC. It is our understanding that a redacted and confidential version of the executed ESA will be filed by DRH. The ESA requires KEC to supply DRH's electric demand not to exceed 20 MW which satisfies the "contracted minimum demand". Furthermore, it is our understanding DRH signed a membership agreement whereby DRH represented that it is a new customer who requires a contract minimum demand of two thousand kilowatts or more and agreed to file a *petition with the South Dakota Public Utility Commission ("the Commission") requesting the Commission to assign the Cooperative as the supplier of electrical service to Applicant pursuant to SDCL 49-34A-56.*

Notwithstanding satisfaction of the "contracted minimum demand" requirement by the ESA, East River consents to the following provision being included in the ESA:

> *Minimum Demand. Notwithstanding the Customer's requirements for kW demand or use of kWh energy, the demand for billing purposes hereunder shall be not less than 2,000 kW for any billing period.*

KEC and DRH have agreed in principle to provision.

1-3) In its Petition, DRH states that it "expects to have a retail load of approximately 20-25 MW with a 90% load factor" and that DRH in combination with Gevo Net-Zero 1 (NZ1) "will have a coincidence factor of 95%" at the time of the East River/KEC peak.

a) How much firm capacity is Basin and East River planning for to reliably supply NZ1?

Answered by Mark Hoffman:

The entire load. Basin is not a party to this proceeding. This answer and any other question regarding Basin is based on East River's information and belief.

b) What is Basin's current capacity position and reserve margin?

Answered by Mark Hoffman:

According to the 2024 SPP Resource Adequacy Report Basin has a total capacity of 4,216 MW, a net Peak Demand of 3,482.4 MW, a resource adequacy requirement of 4,004.7 MW and an excess capacity of 211.3 MW resulting in a LRE planning reserve margin of 21.1%. See page 17 of the report. A hyperlink to the report is provided below.

https://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf

c) What effect will KEC's provision of service to DRH have on Basin's capacity position and reserve margin?

Answered by Mark Hoffman:

It will decrease by the coincident demand of DRH.

d) How will Basin fulfill NZ1's demand and energy requirements?

Answered by Mark Hoffman:

Basin generation and/or market purchases.

e) Will Basin need to procure or construct additional capacity to cover the NZ1 demand?

Answered by Mark Hoffman:

Not to our knowledge.

f) If additional capacity needs to be procured or constructed, will DRH pay the incremental cost of that capacity or a system rate after rolling those costs in with existing rate base? Please explain.

Answered by Mark Hoffman:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence. The legislature has not delegated the Commission with authority to regulate the electric rates of electric cooperatives.

Without waving said objection, capacity charges are included in Basin Electric's rates for demand and energy.

1-4) Provide CAIDI, SAIDI, and SAIFI reliability index data for the portion of East River's system that would serve DRH's load. Also provide a report of outages that would have affected DRH over the last three years.

Answered by Mark Hoffman:

The table below reflects the reliability index data for the East River transmission system. East River does not calculate these based on a certain area or region but rather our entire system. The numbers in the table reflect a 3-year running number so the 2023 numbers include data from Jan 1, 2021, to Dec 31, 2023.

YEAR	***SAIDI***	***CAIDI***	***SAIFI***
2021	*51.04*	*44.79*	*0.56*
2022	*25.87*	*48.28*	*0.54*
2023	*23.16*	*56.49*	*0.41*

East River does not have reports of outages for this location and/or the contemplated transmission configuration that would have affected NZ1 in the last three years.

1-5) Refer to Exhibits 5-1 through 5-4 of DRH's Petition and DRH's response to Staff data request 1-2(b).

a) Provide a list of the transmission facilities East River would move forward with and construct if KEC does not serve DRH's load.

Answered by Mark Hoffman:

[Trade Secret Data Begins]

[Trade Secret Data Ends]

c) Identify the timing of East River's proposed transmission buildout that would still occur without the DRH load addition as identified in subpart a).

Answered by Mark Hoffman:

Timing would not change.

d) Would the timing of the transmission build out be different if KEC serves the DRH load? Please explain.

Answered by Mark Hoffman:

No.

e) Provide justification for East River's proposed transmission retirements. The response should include the age and current condition of the 69 kV lines that are proposed to be retired.

Answered by Mark Hoffman:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waving said objection, Here is a list of line sections that will be replaced with the project:

Line Section	***Age***	***Miles***	***Conductor***	***Structure Type***
Yale to Willow Lake Tap	*1963*	*13.5*	*4/0 ACSR*	*TH*
Willow Lake Tap	*1963*	*9.4*	*4/0 ACSR*	*TSP*
Willow Lake Tap to DeSmet Tap	*1963*	*12*	*4/0 ACSR*	*TSP*
Lake Preston to DeSmet Tie	*1964*	*13.5*	*4/0 ACSR*	*TSP*
Lake Preston Tap	*1986*	*13.5*	*336 ACSR*	*TSZ*
Oldham Tap	*1967*	*3.6*	*1/0 ACSR*	*TSP*
Madison North Tap	*1985*	*26*	*336 ACSR*	*TSZ*

For the TSP structure type, East River has an ongoing initiative to remove this structure type from our system due to reliability concerns. This type of assembly has caused breaker operations due to the failure of the post top insulators. The material on the insulators is breaking down and causing phase-to-ground faults via insulator flashovers. The poles in the TSZ and TH structure types in this area of the system are not adequate to support the conductor upgrades required to serve the proposed new loads in the Kingsbury County and surrounding area, requiring a line rebuild. The new general *structure type will be a TP-Y1-F/G 115. This is our current standard structure type and approved by the Rural Utility Service for use.*

The conductor will be required to be upgraded per the SPP 2024 ITP study and East River's load connection transmission study to 795 ACSR.

In addition, East River plans to relocate the line sections to be built along section line roads rather than cross country along the quarter line. This is a design standard East River strives to maintain for less impact during construction and maintenance and speed of response during outage conditions.

f) If KEC does not serve the DRH and NZ1 load, would East River's transmission upgrade plan still be constructed at 115 kV rather than 69 kV? Please explain why or why not.

Answered by Mark Hoffman:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waving said objection, Yes, 115 kV system voltage would be utilized to serve the other loads in the area. Due to load growth, in addition to DRH and NZ1, a 115 kV system needs to be developed to provide adequate reliable service to Kingsbury Electric and adjacent East River member systems.

g) Will East River's transmission upgrade plan be cost shared across the SPP system? If yes, please provide the estimated cost that will be shared and how that amount will be cost shared across the SPP system.

Answered by Mark Hoffman:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

*The current 2024 ITP Final Project List shows the transmission upgrades identified in the Petition. This information will be used to approximate the increase in East River's Annual Transmission Revenue Requirement (ATRR) associated with the upgrades. **[Trade Secret Data Begins]** xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxx **[Trade Secret Data Ends]** SPP sets the transmission rates for the area and will determine how the East River ATRR for the upgrades is allocated between the zonal and regional transmission rates under the SPP Tariff. The allocation of the ATRR between the zonal and regional transmission rates will have a significant difference on rate impacts within the zone. Until SPP decides how to allocate the upgrades between the regional and zonal transmission rates we can't determine the exact SPP transmission rate impact.*

The SPP Tariff defines the cost allocation for facilities, and network upgrades at 115-kV will typically be allocated one third to the regional rate and two thirds to the zonal rates. However, our understanding is that SPP will perform a benefits test to ensure the facilities provide a regional benefit (i.e., support the bulk transmission system) to determine whether the costs should be allocated regionally.

We do not know when SPP will decide upon regional and zonal transmission rates. They may have already performed the benefits test as part of the ITP rate impact assessment, but East River has not been notified of their determination. We expect to be notified when we receive the Notification to Construct.

1-6) In its Petition to Intervene and Comments, Otter Tail states: "Otter Tail's load in the SPP zone pays SPP tariff charges meaning that Otter Tail customers must help to pay for this potentially excessive buildout through pancaked rates." Otter Tail's Petition to Intervene and Comments further states "[r]equiring Otter Tail's customers to bear these costs, is contrary to the public policy that underpins South Dakota's exclusive territory statutes."

Does East River dispute Otter Tail's claim that its customers must help pay for a potentially excessive buildout? If yes, please explain why and provide support as to why Otter Tail's customers won't help pay for a potentially excessive buildout.

Answered by Mark Hoffman:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence. The statutory factors for Commission consideration do not include or permit any consideration of effects, if any, on the electric provider who is losing territory.

Without waving said objection, Yes. We dispute this claim that this is an extensive buildout. This planned upgrade replaces existing line sections that were planned by East River, to be upgraded for age/condition and load growth. This plan does not overbuild or provide any unnecessary duplication of facilities. The upgrades were proposed to SPP in a FERC-approved regional transmission planning process and were selected by SPP as the best alternative among the options they evaluated. The proposed upgrades provide support for the DRH and NZ1 load, other new loads in Kingsbury County, and mitigates low voltage issues for contingencies in the Brookings area. It is our understanding SPP would not approve an upgrade that was considered to be "excessive."

In addition to the NZ1 load, additional dairy load and possibly digester loads are being considered in Kingsbury County. New dairy loads are expected to be in the 8.5 to 10 MW range with new digester loads up to 7.5 MW. The most certain dairy loads are in western Kingsbury County with an additional dairy expected in southeast Kingsbury County.

Because these are loads that are not currently operating, we assume the loads will be similar to other dairy loads on the East River system (high load factors).

The upgrades in the Kingsbury County area are included in the final portfolio of projects recommended by SPP in the 2024 ITP. The portfolio of projects recommended for the Upper Missouri Zone (UMZ) shows significant benefit to cost ratios. In fact, the SPP rate impact analysis for the UMZ showed the average retail rate payer could potentially see a reduction of $68.85 to $75.69 in their monthly bill (i.e., expected benefit for the average retail ratepayer based on consumption of about 1,000 kilowatt hours per month in 2033 based on 2024 dollars, discounting at a 2.0% inflation rate). Further in South Dakota the rate impact analysis is projected to have a reduction of $68.78 to $75.61. This is based on the Rate Impact section of the 2024 ITP Report on pages 189-191, marked Exhibit 2 attached hereto.

1-7) Does East River, Basin, or SPP need to perform any studies on the proposed large load addition to East River's transmission system? If yes, please identify what studies have been completed, or will need to be completed, and the timeline for those studies.

Answered by Mark Hoffman:

Yes. East River completed a load connection transmission system study which was completed on November 1, 2023 marked as Exhibit 1 attached hereto. ***[Exhibit 1 is confidential trade secret data].*** *The load was included in SPP's 2024 Integrated Transmission Planning (ITP) assessment. SPP identified the needs resulting from the loads and solicited upgrades from stakeholders to mitigate the needs. East River submitted its proposed upgrades which SPP evaluated against other options but ultimately selected the East River proposed upgrades as the best solution. See the draft copy of the SPP study as submitted to the SPP Markets and Operations Policy Committee (MOPC) marked Exhibit 2. This is the version as posted on October 7, 2024. The study report and associated system upgrades are being reviewed by stakeholders and will be on the October meeting agenda of the SPP Board of Directors for their review and approval.*

1-8) Has SPP, Basin, or East River conducted any studies to determine if the DRH large load addition has an impact on SPP transmission congestion costs or LMPs? If yes, please summarize the results of the studies and provide a copy of the studies. If no, identify the studies that will be completed, if any, to assess the large load addition's impact on the transmission system.

Answered by Mark Hoffman:

The evaluation of congestion costs requires the use of special software that East River and Basin do not own. Transmission system congestion is addressed through the market economic analyses performed by SPP during the ITP assessments. The study report and associated system upgrades are being reviewed by stakeholders and will be on the

October meeting agenda of the SPP board of directors for their review and approval. See 1-6.

1-9) Has SPP, Basin, or East River conducted any studies to determine if the DRH large load addition has an impact on flowgates used, or would be used, in market to market coordination under the MISO/SPP Joint Operating Agreement? If the answer is yes, please provide a summary of the study results and provide a copy of the study. If the answer is no, identify the studies that will be completed, if any, to assess the impact the large load addition would have on market to market coordination.

Answered by Mark Hoffman:

SPP, in their NERC defined roles as Planning Coordinator and Reliability Coordinator for the SPP region, performs the system capability assessments and calculations, monitors and establishes flowgates, and performs congestion management. SPP performs the system studies and flowgate assessments on a periodic basis. SPP is also responsible for market-market coordination between SPP and MISO.

East River and Basin do not study impact on flowgates.

1-10) On page 10 of DRH's Petition, it is stated that "the Commission can be assured that the rates KEC will charge DRH are sufficient to recover its costs associated with serving the load."

a) Please provide any data East River has in its position that could be used at hearing to support the statement above.

Answered by Scott Shewey, East River Chief Financial Officer:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence. The legislature has not delegated the Commission with authority to regulate the electric rates of electric cooperatives.

Without waving said objection, NZ1 and DRH intend to purchase power from KEC via a large load rate. The large load rate recognizes the competitive nature of large end use loads while recovering power supply and investment costs associated with these loads. The rate is set at power supply cost plus other system costs, which recovers maintenance, administrative expenses, and other system-wide costs. The large load rate is subject to periodic review by the KEC Board of Directors and can be modified to reflect the cost. The members of KEC elect those that represent them and manage their system. Thus, those customers have a voice in their service and its oversight.

b) What effect, if any, will KEC serving DRH have on KEC's existing customers' rates, East River's existing customers' rates, and Basin's existing customers' rates?

Answered by Scott Shewey:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waving said objection, East River and KEC rates are designed to recover costs directly associated with the load and system-wide shared costs. Adding a load of this size will decrease the system cost recovery on other rate classes.

c) Will the margin on DRH's sales offset any additional costs that existing customers may incur due the large load addition? Please provide any data and calculations supporting the response given.

Answered by Scott Shewey:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waving said objection, See answer to 1-10.b above. Rate recovery above cost, or margins, collected by cooperatives are used to supplement short-term capital needs and are returned to members over time.

1-11) Will DRH pay for its share of usage on East River's transmission buildout in Exhibit 5 that isn't covered under the CIAC agreement? More specifically, please provide the forecasted transmission costs associated with DRH's load and explain how those costs will be recovered from DRH.

Answered by Scott Shewey:

Objection for the reasons that it is overly broad, vague, ambiguous, burdensome and is not reasonably calculated to lead to the discovery of admissible evidence.

Without waving said objection, yes, DRH will pay for its share of the transmission buildout which is included in the rate recovery of system-wide costs. The cost is recovered on both the demand and energy charges.

1-12) Referring to the "East River Kingsbury County Substation – Oneline" diagram in Exhibit 5-4 of DRH's Petition, please identify the meter that DRH's demand and energy will be metered at for billing.

Answered by Mark Hoffman:

Meters 3, 4 and 5 on the diagram, subject to final design of the substation and facility.

1-13) Has East River made any investment to date in anticipation of KEC serving the DRH load? If yes, please identify those investments and the costs East River has incurred.

Answered by Mark Hoffman:

Yes, we have costs assigned to the project including labor, design, land acquisition, and have ordered long lead time equipment.

1-14) Does East River have experience with reliably serving large loads similar to the size of DRH and NZ1? If yes, please summarize East River's experience with large loads. If no, please explain how East River is prepared to provide the operations and maintenance support for East River's facilities to reliably serve the DRH and NZ1 loads.

Answered by Mark Hoffman:

East River through its members serve nine ethanol plants, a sugar beet plant, and 17 other large loads. East River members also have an additional three large loads that have ESAs and are under development.

Daniel J. Brown, Attorney for East River, hereby objects to certain requests, as shown above.

Dated this 18th day October, 2024.

East River Electric Power Cooperative, Inc.

By: /s/Daniel J. Brown

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